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)

CLEAN COALITION OPENING COMMENTS ON ALJ RULING

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ALJ RULING

The Clean Coalition respectfully submits these comments on the Administrative Law Judge's Ruling dated June 27, 2011.

The Clean Coalition is a California-based policy organization, part of Natural Capitalism Solutions, a non-profit entity based in Colorado. The Clean Coalition focuses on policies that deliver cost-effective and timely clean energy, including within the underserved "wholesale distributed generation" (WDG) market segment, which is comprised of wholesale generation projects interconnected to the distribution grid. WDG is a particular focus given the combination of cost-effective energy and economic benefits that it delivers, while at the same time avoiding all of the challenges associated with transmission build-outs. The Clean Coalition is active in proceedings at the California Public Utilities Commission, California Air Resources Board, California Energy Commission, the California Legislature, US Congress, the Federal Energy Regulatory Commission, and in various local governments around California.

Our main points are as follows:

- We recommend a three-phased approach to implementing SB 32: 1) an immediate advice letter approach to expand project size to 3 MW before end of 2011, with pricing to remain at 2009 MPR plus Time of Delivery; 2) an interim decision implementing the other aspects of SB 32 identified in the ALJ Ruling, with pricing at 2009 MPR plus TOD plus a simple Locational Benefits proxy; 3) a final decision implementing remaining aspects of SB 32 and modifying the Locational Benefits calculation to provide more accurate compensation.
- Two key benefits for renewable energy projects have hard deadlines by year's end: the 100 percent bonus depreciation allowance and the section 1603 federal cash grant program (in lieu of tax credits). These programs don't expire until the end of 2012 but projects have to have a certain amount of work done by end of 2011, or money invested under "safe harbor" provisions, neither of which is likely to happen without a PPA in place.
- These tax benefits are so substantial for developers that the Commission should ensure that key aspects of the new SB 32 program are in place in time to allow developers to utilize these major benefits. Time is of the essence, so

we recommend an advice letter approach to increase the project size cap to 3 MW before the end of 2011, with pricing to remain at the 2009 Market Price Referent plus Time of Delivery. The Commission does not have to issue any decision to implement key provisions of SB 32; rather, the Commission should, in order to capture the substantial tax benefits just mentioned, simply order the utilities to include key provisions of SB 32 as part of the advice letters they're already required to file in August in this proceeding.

- The Commission should then issue an interim decision implementing the aspects of SB 32 identified in the ALJ Ruling, with pricing at 2009 MPR plus TOD plus a simple proxy for Locational Benefits (Transmission Access Charges only), as soon as possible – hopefully before the end of 2011. 2009 MPR plus TOD plus Locational Benefits allows time-dependent and location-dependent benefits to be recognized in a manner that leaves ratepayers economically indifferent.
- Pricing from the start of 2012 forward should also include utility-specific volumetric degression, as in the CSI program. We recommend a new pricing term be used for SB 32: "Volumetric Market Price" or VMP, to move away from the MPR terminology and reflect the key volumetric degression feature of our recommended pricing formula.
- The third phase of SB 32 implementation, which will take place in 2012, should implement the remaining aspects of SB 32 and refine the Locational Benefits pricing formula to more accurately reflect the actual Locational Benefits for each project, rather than the simple proxy we recommend as the starting point.
- The Commission should impose a COD requirement of 18 months from contract completion, with one six month extension allowed for regulatory delays or other events outside the control of the developer.
- We recommend also, as described in our March 7, 2011, Opening Brief, that the Commission use its inherent authority to expand the SB 32 project size to 5 MW in the third phase. Just as the Commission significantly modified the AB 1969 program by doubling its capacity from 250 MW to 500 MW and extending eligibility to any utility customer, rather than only water and waste water agencies, the Commission should use its authority in this case to create a more robust feed-in tariff program. The key rationale for doing so is the expansion of Fast Track eligibility to 5 MW by PG&E and CAISO.
- Deliverability issues should be deferred until the third phase of this proceeding because there is no law requiring full capacity deliverability,

including SB 32, which only requires that any resource adequacy credit resulting from SB 32 projects counts toward utility resource adequacy requirements – not that full capacity deliverability is required.

- The Clean Coalition does not support any variation of auction pricing for SB 32, which calls clearly for a set price. Rather, we strongly recommend that the Commission set a baseline price at 2009 MPR plus TOD plus Locational Benefits and then gauge the market reaction. If market response is robust, prices should degress under a set formula. If market response is weak, the Commission should reconsider its pricing formula.
- The Clean Coalition also opposes any pricing formula that attempts to rely on signed PPAs from similar programs in California, rather than operational projects. It is well known that competition for PPAs is fierce and that auction programs promote a "race to the bottom." This results in many signed PPAs that are unfinanceable. If the Commission looks to other projects for pricing guidance, it must look to operational projects only.
- Interconnection issues should be deferred until the third phase of this proceeding because the Rule 21 Working Group is convening concurrently but won't be finished with its process until early 2012, at the earliest.
- SB 32 creates a new 750 MW program so the Commission should clarify how projects in the AB 1969 application queue (applied but not yet in receipt of a PPA) should be managed. We recommend that projects that don't yet have a signed PPA with an investor-owned utility should be given priority over new applicants under SB 32 but should also have to submit a development deposit of $10,000 per megawatt to maintain their queue position. This option should only be made available when the new SB 32 program becomes "live."
- The Commission should clarify, and require utilities to clarify in their advice letter filings in 2011, that SB 32 projects are not precluded by a CSI or SGIP project on the same property or owned by the same customer, with suitable explanation of the variations presented by SB 32's full sales or excess sales options.

I. General Comments

The Clean Coalition again commends the Commission for recognizing the importance of unleashing the wholesale distributed generation ("WDG") market as an essential component in California's pursuit of economically and environmentally sustainable energy supplies for the State of California, and of achieving the Renewables Portfolio Standard (RPS) mandates and greenhouse gas reduction goals on schedule.

The urgency of developing the WDG market was increased by a January, 2011, Ninth Circuit decision striking down federal transmission corridors, including in California, based on its view that the federal government had failed to adequately consult with the states.[1] This decision very likely has added years of delay in building a number of new transmission lines required to meet California's 33% RPS by 2020 under the widespread assumption that central station renewables will comprise the lion's share of this mandate.

Additionally, in late February an environmental group (CARE) and a number of Native American tribes filed a federal lawsuit challenging more than 3,000 MW of concentrating solar and solar PV projects to be sited on federal lands in California.[2] The Clean Coalition has no opinion on the merits of these recent events, but they cast significant doubt on the mega-project approach to achieving California's RPS. WDG can meet much of the RPS mandate in an expedited and cost-effective manner <u>if the Commission provides the necessary market certainty to jumpstart this market to scale</u>.

A. The Commission should pursue a three-phase process for implementing SB 32

Time is of the essence in this proceeding and we appreciate the ALJ Ruling's recognition of this urgency (p. 4): "I intend to establish a schedule that provides for full implementation, if possible, or partial implementation by the end of 2011. Parties should comment on this goal." The Ruling also states that the staff goal is to have a Proposed Decision issued by the end of the year, which is incompatible with the statement just quoted because it will take many months after a PD is issued before "full implementation" is achieved. This is the case because comments must be filed on the PD (opening and reply), a Final Decision voted on by the Commission, advice letters

[1] http://tdworld.com/overhead_transmission/transmission-corridors-overturned-0211/.
[2] latimes.com/news/local/la-me-solar-suit-20110224,0,539145.story.

issued by the utilities, comments filed on the advice letters, and then a final resolution issued by the Commission approving the advice letters. This process will take 6-9 months, resulting in full implementation around the middle of 2012 at the earliest.

It is our view that partial implementation is, however, possible by the end of 2011 – and is also highly desirable because of substantial federal tax benefits with hard deadlines at the end of the year and because of the lengthy delays already experienced with respect to implementing SB 32.

It is the necessarily lengthy decision-based process proposed in the ALJ Ruling that prompted our strong recommendation that the Commission instead implement key aspects of SB 32 (primarily the increase to 3 MW per project) in advice letters that the utilities are already scheduled to file in this proceeding. This advice letter approach would dramatically increase the pace of implementation of key aspects of this new program. We understand that pricing will be controversial, which is why we recommend below that pricing remain at 2009 MPR plus TOD for this rapid implementation advice letter approach.

B. SB 32 creates a new 750 MW program and AB 1969 projects should not necessarily count against the new program limit

SB 32 creates a new 750 MW program and the Clean Coalition asks the Commission to clarify how AB 1969 projects will be treated with respect to SB 32. The AB 1969 programs have been operational for some time now, albeit ineffective in their goals (as discussed above). We recommend that AB 1969 projects in the utility application queue that want to transition to an SB 32 PPA be allowed to do so, and be allowed to maintain their application queue and interconnection queue position (if they have also applied for interconnection). However, a new interconnection study will obviously be required if the applicant has applied for a single 1.5 MW project and is seeking to interconnect a larger project under SB 32. Moreover, applicants should be required to submit a deposit – we recommend $10,000 per megawatt – in order to maintain their application queue position.

The application queue position is important because it's likely that even the new 750 MW program (with about 550 MW comprising the IOU portion) will be fully subscribed relatively quickly, judging by the great interest in recent auction programs in California. It is not fair to penalize AB 1969 applicants who have been waiting for a signed PPA due to delays by the IOU (if this is the case), which is why we recommend allowing applicants who have not received a signed PPA to be able to maintain their queue position under the new SB 32 program.

We also recommend that the Commission not count signed AB 1969 PPAs or operational projects, completed before SB 32 is implemented, against the 750 MW of the new SB 32 program. Section 399.20(f) states:

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

SB 32 modified section 399.20, which was codified originally by AB 1969. By modifying section 399.20 the Legislature created a new program, to take effect when the Commission implements SB 32. The AB 1969 program has been operational since the Commission implemented that law and will remain in effect until the Commission implements its successor, SB 32. Accordingly, the Commission should clarify that SB 32 creates a new 750 MW program and also clarify how AB 1969 projects (in queue, with a signed PPA, or operational) will be managed with respect to the new SB 32 program.

C. The Commission should order the utilities to clarify how AB 1969 and SB 32 projects interact with property owners who have CSI or SGIP projects on the same site

The Commission should clarify, and require utilities to clarify in their advice letter filings in 2011, that SB 32 projects are not precluded by a CSI or SGIP project on the same property or owned by the same customer, with discussion of the variations presented by the full sales or excess sales options available under AB 1969 (and presumably to be offered under SB 32 also).

D.07-07-027, which implemented AB 1969, states: "We approve proposed tariffs/standard contracts which make clear that participants may not simultaneously obtain benefits from both this tariff and the SGIP, net metering programs, California Solar Initiative, or other similar programs."

Some parties have interpreted this language to mean that any party seeking an AB 1969 contract who has an existing CSI or SGIP project on-site is ineligible to sell power from a different project on the same site under AB 1969. It seems clear, however, that this is not the intent of the Commission's language. Rather, the intent seems to be that an applicant may not for the same project receive CSI, SGIP or net metering incentives and also sell power under AB 1969.

We request that the Commission require the utilities to include in their August advice letter filings a clarification that this prohibition is project-specific and not applicant-specific.

D. Developers should have 18 months from contract completion for COD, with one six-month extension

As in the new RAM program, we recommend that the Commission provide 18 months from contract completion for COD, with one possible six-month extension for regulatory delays or other factors outside of the developer's control.

E. The Commission should expand the SB 32 program to 5 MW per project in its final phase, using its inherent authority

We recommend also, as described in our March 7, 2011, Opening Brief, that the Commission use its inherent authority to expand the SB 32 project size to 5 MW in the third phase of SB 32 implementation. Just as the Commission significantly modified the AB 1969 program by doubling its capacity from 250 MW to 500 MW and extending eligibility to any utility customer, rather than only water and waste water agencies, the Commission should use its authority in this case to create a more robust feed-in tariff program. The key rationale for doing so is the expansion of Fast Track eligibility to 5 MW by PG&E and CAISO.

We flesh out our recommendations below and also respond to the Commission's questions in the ALJ Ruling.

II. Commission Questions

The Commission asks a number of questions in the ALJ Ruling, which we address in turn below.

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.

2) Explain whether the price for electricity purchased under § 399.20(d), as amended by SB 2 1X, must or should be based on the MPR as currently calculated.

3) Explain whether the price for electricity purchased under § 399.20(d) must or should be based on the MPR as currently calculated with the addition of new adders, as suggested by parties in the March 2011 briefs.

4) Explain the benefits and the drawbacks of continuing to use the MPR as the basis of the price for the program under § 399.20 given the statutory changes.

We address questions 1-4 jointly and describe our preferred pricing mechanisms below. We recommend a three-phased approach for implementing SB 32: 1) the Commission should immediately order the utilities to include in their advice letters expansion of project size eligibility to 3 MW while keeping pricing at the 2009 Market Price Referent plus Time of Delivery; 2) the Commission should then proceed with an interim order that includes volumetric pricing degression and a simple proxy for Locational Benefits in an expanded pricing formula, with a Proposed Decision issued before the end of 2011; 3) as soon as possible in 2012, the Commission should implement the remaining aspects of SB 32 in another decision, with pricing at 2009 MPR plus TOD plus a more refined approach to Locational Benefits.

1) Advice Letter approach with Market Price Referent plus Time of Delivery

Given the urgent need to have a functional SB 32 program before the end of 2011, in order to take advantage of significant federal tax benefits (section 1603 cash grant[3] and 100 percent bonus depreciation[4]), the Clean Coalition recommends that the Commission[5] immediately order the utilities to include in their advice letters (already required in this proceeding) expansion of project size eligibility to 3 MW.

Attachment A includes a short statement supported by a number of solar developers who agree with the Clean Coalition that the 3 MW size limit expansion should be achieved in 2011.

This is our preferred approach for immediate partial implementation of SB 32, which should allow a functional and effective SB 32 program to be created before the end of 2011, providing sufficient time for developers to complete PPAs under the new program and proceed with sufficient development work (either actual construction or committing funds) to qualify for the substantial federal tax benefits. Both of these federal programs expire at the end of 2012 but require significant development work or financial investment to be completed by Jan. 1, 2012.

Without this immediate advice letter approach, it will be literally impossible to create a functional program by the end of 2011. This is the case because, as mentioned, any order-based approach will require a PD, opening and reply comments, a final decision, advice letter filings, comments and a final resolution approving the advice letters. This cannot be completed before the end of 2011.

We also recommend, as mentioned, that the August advice letter filings include a clarification that AB 1969 and SB 32 projects aren't precluded by a CSI, SGIP or net-metered project on the same site as the new AB 1969 or SB 32 project. Rather, this preclusion is project-specific, not applicant-specific.

We describe below our further recommendations for an interim decision that should be pursued either after the advice letters are issued <u>or</u> will pertain if the Commission decides not to pursue the immediate advice letter approach for interim implementation.

2) Interim decision with MPR plus TOD plus Locational Benefits pricing

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[3] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US53F.

[4] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06F&re=1&ee=1. This short article clarifies recent IRS guidance stating that projects must be placed in service before Jan. 1, 2012, which means that at least 10% of the project cost must be expended by that time, which is unlikely to happen without a signed PPA: http://www.nawindpower.com/e107_plugins/content/content.php?content.8046.

[5] CEERT's March 7, 2011, Opening Brief on SB 32 Implementation recommended a similar approach.

SB 32 is intended to spur market growth in the wholesale DG sector for projects 3 MW and smaller. Projects of this size can be developed relatively quickly, sometimes taking advantage of faster and less costly interconnection procedures as well as less time-consuming permitting procedures in some circumstances.

AB 1969, the predecessor to SB 32, required MPR plus TOD pricing and failed to recognize "locational benefits," while targeting project sizes that were rarely economically viable at that price level – as is made clear by the handful of new projects that have come online under AB 1969 in its three year existence.

It appears that in the last year, however, judging by much stronger interest in the AB 1969 programs, pricing has become, or is becoming, sufficient even for the 1.5 MW size limit. SCE's program has over 200 MW in its queue; PG&E does not seem to provide public information for its application queue (only completed PPAs). It is important to recognize, however, that SCE's queue represents only applications for PPAs, not signed PPAs. We have some anecdotal evidence that applicants may be applying for SCE's CREST program more for the interconnection benefits than for the PPA.

Regardless, SCE's program has serious flaws in its PPA, and this is the likely cause of the very low number of signed PPAs. SCE is working to resolve its PPA issues at this time and we expect a new contract to be submitted to the Commission in August (which is the vehicle by which we hope to see the 3 MW expansion of project size take place in 2011).

Even with increased interest in the AB 1969 programs in the last year, there are still literally only a handful of new projects that have come online in the entire state (SCE's website shows just two completed projects and PG&E's show's only one new project online, as well as a few existing projects with new PPAs under AB 1969) – and AB 1969 has been operative for 2.5 years now. Clearly, the AB 1969 feed-in tariff program has failed in its original intent.

SB 32 seeks to address the failure of AB 1969 to produce actual "steel in the ground" by allowing projects up to 3 MW and allowing pricing that includes locational benefits as well as TOD. As we described in our opening brief[6] to the Commission early this year, SB 32 requires the Commission to "consider" locational benefits but leaves the decision to boost the PPA price due to locational benefits optional.[7]

[6] http://docs.cpuc.ca.gov/cyberdocs/WebQuickstart.asp?DOC_ID=E39978.

[7] We stated in our March 7, 2011, opening brief: "Section 399.20(e) also requires the Commission to consider "locational benefits" in setting prices and specifies that the Commission "may" provide

The interim decision should include a locational benefits pricing adder

The Clean Coalition recommends including in the interim decision MPR plus TOD pricing with volumetric degression and locational benefits (LBs). We describe our degression recommendations below. With respect to locational benefits, we see a number of possibilities. Our preferred method for calculating locational benefits is to recognize, at the least, that all distribution-interconnected projects save ratepayers money. That is, distribution-interconnected projects avoid transmission-related costs that are paid by ratepayers for transmission-interconnected projects. These charges are known as Transmission Access Charges (TAC).

We recommend a simple proxy for Locational Benefits in the interim decision and a more refined formula to be adopted in the final phase in 2012. CAISO charges all utilities TACs for high voltage and low voltage transmission lines ("low voltage" does not mean distribution lines in this context). We propose using the average TAC for each utility as a simple proxy for Locational Benefits, which represents the long-term savings for ratepayers from avoiding new transmission line construction for larger projects (renewable or non-renewable). We are <u>not</u> suggesting that using TACs is a completely accurate calculation of Locational Benefits. Rather, we are suggesting that the average TAC should be used as a simple proxy for expedited implementation, with a more refined formula for Locational Benefits to be developed in the final phase of SB 32 implementation (which we describe below).

The average TAC for all three IOUs is 1.1 c/kWh in 2011. We recommend that this TAC be levelized over the life of the SB 32 contract, resulting in, <u>for illustration purposes only</u>, about 1.5 c/kWh[8] added to the PPA price. Accordingly, again as an illustration only, our recommended pricing formula for the interim decision is 2009 MPR plus TOD plus 1.5 c/kWh for TACs as a proxy for Locational Benefits.

We also recommend a refinement to the 2009 MPR price. Rather than using the entire COD table, we recommend using only a single year from the 2009 MPR resolution, reflecting the expected COD for new SB 32 projects. Providing developers a higher PPA

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payment for locational benefits. There are, accordingly, four price components that the Commission should consider: the Market Price Referent (mandatory), Time of Delivery payments (voluntary), "all current and anticipated environmental compliance costs" (mandatory), and locational benefits (mandatory consideration, optional inclusion). The Clean Coalition urges the Commission to include all four cost components in the SB 32 payment."

[8] Assuming 3% inflation over twenty years results in a levelized value of 1.547 c/kWh.

price for completion of projects further out in time, as the current MPR table does, provides a disincentive for early construction. The Clean Coalition is anxious to see projects constructed as quickly as possible so we recommend that SB 32 pricing, while appealing in name to the 2009 MPR resolution, should in fact use either the 2013 or 2014 COD date only from the resolution, reflecting our recommendation that developers be provided 18-24 months from contract completion for construction (if projects obtain contracts in late 2011 or early 2012, they should come online in 2013 or 2014).

If we apply this formula to the existing 2009 MPR resolution 2013 and 2014 COD years, we achieve the pricing in Table 1. It is our view that this is itself a rational and defensible pricing formula and also one that achieves pricing sufficient to support all types of renewables up to 3 MW, when Time of Delivery is added.

Table 1. *Projected SB 32 pricing based on 2009 MPR plus 1.5 c/kWh locational benefits.*

	Without TOD				With 25% TOD			
	10-Year	15-Year	20-Year	25-Year	10-Year	15-Year	20-Year	25-Year
2013	0.110	0.117	0.124	0.127	0.138	0.147	0.155	0.159
2014	0.114	0.121	0.128	0.131	0.142	0.151	0.160	0.164

The following discussion provides more detail on the TAC calculation. The total cost of providing transmission service, including the return, is referred to as the utility's retail transmission revenue requirement (TRR). The collective revenue requirement for all of the utilities that participate in the CAISO is the basis for the TAC, which is ultimately charged to ratepayers.

TACs are paid to the CAISO by load serving entities (LSEs) who then pass those charges on to ratepayers via transmission charges on retail bills. There are separate TACs for interconnection on High Voltage (HV) and Low Voltage (LV).

HV TACs are "postage stamp" charges, which means the charge is the same no matter who ultimately owns the transmission facilities. All that matters is total HV TRR and total load. Therefore[9]:

[9] http://www.caiso.com/2afe/2afec4f1394e0.pdf.

HV TAC for all LSEs in 2011 = Filed Annual TRR / Filed Annual Gross Load = $6.5672/MWh = 0.65672 cents / kWh

Note also that any HV voltage transmission upgrades made in the CAISO area by any IOU will drive up Filed Annual TRR and, therefore, HV TACs for everybody. Alameda Municipal Power, for example, expects this number to increase steadily.[10]

If a project connects within the CAISO control area at low voltage (LV) interconnection, the developer will have to pay additional LV TACs. These charges are specific to each IOU territory and are also provided at the CAISO link above in footnote 8. Alameda Municipal Power, for example, interconnects at 115 KV (considered low voltage) in PG&E territory, requiring an additional payment of an LV TAC of 0.48487 cents to CAISO. (See bottom right of middle box at top of page 2 of CAISO document.)

Therefore, Alameda's total TAC charge paid to CAISO = 0.65672 + 0.48487 = 1.14 cents / kWh.

This payment is made to CAISO and CAISO distributes the TACs appropriately to the HV and LV transmission owners. Ratepayers are ultimately responsible for these payments and avoiding these payments translates directly into ratepayer savings in comparison to non-WDG projects.

LV TACs for the three large IOUs are: PG&E, 0.48 c/kWh, SCE, 0.05 c/kWh, SDG&E, 0.83 c/kWh. Averaging these three results in the 1.1 c/kWh HV TAC + LV TAC figure we used for illustration purposes in Table 1.

We find more support for our proposal from the state's municipal utilities. For example, Palo Alto Utilities recently estimated 2.2¢/kWh savings in transmission and distribution losses and fees through the procurement of wholesale DG.[11] The total value includes the savings from avoided transmission fees (1.6¢), and reduced transmission (0.2¢) and distribution losses (0.4¢). There is an additional value (0.7¢) of "local capacity" purchases that are avoided by distributed PV related to its generation profile near the point of demand.

Some parties have argued in R.08-08-009 that SB 32 does not authorize compensation for LBs. The recitals for SB 32, however, make it clear that the Legislature did indeed

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[10] Private communication with the Clean Coalition.

[11] Table 2, 'Overview of Parameters to Consider Regarding Implementing Feed-in-Tariffs for Solar Photovoltaic Systems in Palo Alto," Memorandum from Palo Alto Utilities Department for Utilities Advisory Commission, Feb. 2, 2011 Meeting.

intend for the law to authorize compensation for locational benefits. SB 32, as chaptered, states (Section I(e)):

> A tariff for electricity generated by renewable technologies should recognize the environmental attributes of the renewable technology, the characteristics that contribute to peak electricity demand reduction, reduced transmission congestion, avoided transmission and distribution improvements, and in a manner that accelerates the deployment of renewable energy resources.

3) ***The final phase of SB 32 implementation should include a more refined calculation of Locational Benefits***

In seeking to establish a market price for generation under SB 32, it is important to note that the actual market price for any given product is not a single number, but a price curve reflecting supply and demand. Demand is based on the value of the product to the buyer and is defined by the price offered. The market collectively responds by providing as much supply as is economically viable at the offered price. If the price offered is too low, there will be little if any supply; a higher price will produce a higher supply. "Market price" is, therefore, entirely dependent on the quantity of supply desired. If California desires a specific quantity of generation within a given timeframe, the Commission should offer a price that is sufficient to attract the desired response. The difficulty, of course, is that it is impossible to know in advance exactly how the market will respond to any particular price.

It is also crucial to recognize that previous market responses to auction programs like the solar PV programs or the RPS program offer little guidance for optimal SB 32 pricing because so few actual projects in the relevant size range have been built under these programs. Auction programs can sometimes produce lower prices for ratepayers, but they also promote a "race to the bottom" that encourages developers to propose unrealistic prices. These unrealistic prices often result in PPAs for projects that never get built because the price is too low. We have anecdotal evidence that numerous California PPAs are available for purchase on the secondary market today because the original awardee is unable to build the project at the PPA price. Thus, it is highly important for the Commission to determine SB 32 pricing, if a market data approach is utilized, based on actual projects built, and not based on PPAs awarded.

The Clean Coalition recommends that "price discovery" for the 3 MW and smaller market may best be pursued by initially offering the established pricing of the 2009

MPR plus TOD plus LBs. We were encouraged by PG&E's briefing in R.08-08-009 expressing support for MPR plus TOD pricing, lending further support to our recommendation now. We have enough evidence to suggest that this pricing will lead to a good market response, while not offering developers an unwarranted windfall by providing a higher price than necessary to spur new projects. The market response should result in an established price degression (described further below), similar to what has been used in robust feed-in tariff markets like Germany. In Germany, FIT rates have steadily degressed as market prices have diminished, and yet the market response has remained robust.

Again, the key benefit of MPR plus TOD plus LB pricing for SB 32 projects is that ratepayers are not being asked to pay unreasonable prices for renewables because this pricing formula leaves ratepayers economically indifferent.

Pricing at 2009 MPR plus TOD plus LBs will establish the baseline market response for the new SB 32 program. The very limited response under AB 1969, in terms of just a handful of operational projects over its almost three-year lifespan, demonstrates that pricing has been insufficient. The Clean Coalition feels that the increased SB 32 project size, our recommending pricing formula, and recent decreases in component and some installation costs for many renewable energy technologies, will probably result in a substantially larger market response than under AB 1969.

We recommend also that the Commission adopt the term "Volumetric Market Price" (VMP) for our proposed formula in order to move away from the MPR terminology (which is no longer applicable by law to SB 32) and to directly reflect the volumetric degression feature of our recommendations, which will ensure that ratepayers are not paying too high a price for SB 32 projects.

If the market response under the initial SB 32 pricing is poor (for example, less than 100 MW of new PPAs signed in the first year), the Commission should reconsider its pricing formula. If the market response is good, pricing should degress under an established formula. Successful renewables programs that have achieved rapid growth and prompted declining market prices have used volumetric price degression to protect against developer windfalls and to protect ratepayers. The long term pricing of SB 32 should employ this approach, setting incremental capacity targets and associated pricing reductions. The faster the capacity targets are met by the market, the faster the price declines; in this way the price is market driven and adjusted automatically to maintain the level of supply response desired for the program.

The Clean Coalition recommends the following degression schedule (Table 2) for the VMP, which provides for complete predictability for the entire IOU portion of the 750 MW SB 32 program, while also ensuring that ratepayers benefit greatly from reduced pricing for fully half of the program.

It is crucial that degression occur as in the CSI program: specific to each utility. This is the case because without such utility-specific degression it is very likely that solar in SCE territory would consume much of the program (judging by extant interest in other similar programs). This is not fair to the other utility ratepayers, so each utility's pricing should degress under its own schedule.

Table 2. *Clean Coalition recommended SB 32 VMP degression schedule.*

Tranche	VMP Pricing
First half of each IOU's share	2009 MPR plus TOD
Third quarter of each IOU's share	Minus 5% from 2009 MPR
Fourth quarter of each IOU's share	Minus 10% from 2009 MPR

Locational Marginal Pricing and RECs for rooftop PV

It is likely that the SB 32 program will be dominated by projects at or close to 3 MW unless additional pricing options are included to support smaller projects. Our analysis suggests that ratepayer value is not greatly different for projects as small as 100 kW and up to 5 MW (Table 3, estimates for PPA Rate, which is the base rate independent of TOD, and T&D costs are derived from various public sources), so there is a good rationale to not disincentivize rooftop PV with SB 32's pricing formulas.

Table 3. *Clean Coalition analysis of ratepayer cost for various size renewable projects.*

	Distribution Grid					T-Grid
PV Project size and type	**100kW roof**	**500kW roof**	**1 MW roof**	**1 MW ground**	**5 MW ground**	**50 MW ground**
Required PPA Rate	**15¢**	**14¢**	**13¢**	**12¢**	**11¢**	**10¢**
T&D costs	**0¢**	**0-1¢**	**1¢**	**1¢**	**1-2¢**	**2-4¢**
Ratepayer cost per kWh	**15¢**	**14-15¢**	**14¢**	**13¢**	**12-13¢**	**12-14¢**

Locational Marginal Pricing (LMP) and Renewable Energy Certificates (RECs) are potential tools available to the Commission to support SB 32 projects. LMP offers a means for providing a more accurate calculation of Locational Benefits (rather than the simple proxy we recommend for interim pricing). We do not recommend using RECs for all SB 32 projects because we don't think they'll be needed and they add another layer of complexity to the program. Rather, we recommend RECs as a possible tool for providing additional price support for roof-based PV. We recommend that the Commission tackle these additional pricing considerations in the final decision in this proceeding – the third tier of our three-tiered approach for implementation.

"Rooftop RECs" could be included in the final decision as a way to support rooftop PV. The Commission could, under this approach, poll developers in this proceeding for the additional price support required to make rooftop PV projects viable under SB 32 – recognizing, again, that ratepayers are indifferent to such pricing boosts because of the savings from transmission and distribution upgrades. Because rooftop PV can't utilize single-axis tracking at this point in time, annual production is typically about 20-25% less than for an equivalent ground-mounted tracking system. However, tracking systems add some costs to a system and rooftop systems can avoid CEQA (California Environmental Quality Act) review entirely, which is not always the case for ground-mounted systems, so it is likely that a rooftop REC that provides about a 10% boost over the otherwise-applicable SB 32 price would be sufficient to support the rooftop market. We are not at this point necessarily recommending this figure; rather, the Commission should survey developers and other stakeholders in this proceeding to arrive at the correct figure.

LMP is another tool that could be used, either as a more direct rationale for a rooftop PV price adder or as a more refined approach for Locational Benefits applicable to all SB 32 projects. The LMP approach is, however, more complex and time-consuming to implement than the Rooftop REC approach. The rationale for LMP is that the closer power production is to load, the less line losses and congestion losses occur and the less distribution upgrades are required. If, for example, a 100 kW PV system was installed on a warehouse as an SB 32 project, power would probably be consumed on-site most of the time, requiring almost no grid investments for the project to be interconnected and integrated.

A possible LMP approach in this proceeding would be to have the utilities identify average congestion and line losses throughout their service territory, and then identify all areas that are average or higher. In these areas alone, the LMP boost would apply for rooftop PV. Again, it is likely that only a 10% boost over the otherwise-applicable SB 32 price would be sufficient to support projects as small as 100 kW.

A key benefit of our pricing approach is that pricing for SB 32 projects will, under our recommendations, start out low and go higher over time, and then fall again as volumetric degression sets in, resulting in a bell curve for pricing. This is a beneficial price signal because it will test the market's appetite for various low-to-high pricing regimes and protect ratepayers by starting low, then degress over time as market interest increases. This approach will not only provide a lower price initially, it will also provide additional time for the Commission and stakeholders to work through the issues relating to pricing without unnecessarily delaying program implementation.

5) Under the current RPS program rules each annual RPS Solicitation triggers an update to the MPR values. Consistent with CPUC decisions, Energy Division staff will calculate a 2011 MPR for the 2011 RPS Solicitation. Due to the statutory changes in SB 2 1X, it is not clear whether the Commission will continue to calculate an MPR to establish an RPS cost limitation. Parties should explain whether a new trigger for an MPR update is necessary and/or a schedule for how the MPR should be updated going forward.

The Clean Coalition, as stated above, believes that SB 32 pricing should be based on the 2009 MPR resolution as the baseline pricing. There is no statutory requirement, with the passage of SB 2 1X, for SB 32 pricing to be tied to the MPR moving forward. We have proposed, however, that it be initially tied to the 2009 MPR because of reasons stated above (establishing a baseline for price discovery). **We believe that the <u>2011</u> MPR resolution need not have, and should not have, any bearing on SB 32 pricing**.

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.*

While the Clean Coalition believes there is ample room for the Commission to craft technology-specific or product-specific pricing options, we do not at this time recommend such an approach. Simplicity is a virtue and we recommend a single pricing formula that recognizes time-dependent value (TOD) and location-dependent value (locational benefits) automatically. Thus, a single pricing formula applies to all SB 32 projects under our recommendations, at each phase in this proceeding, but it is flexible enough to provide the right kind of incentives to the market – while also providing maximal ratepayer value.

The "market price of electricity" is conditional upon the associated attributes or characteristics (if any) defined for the electricity that is to be provided by the market. If the buyer requires generation from a specific technology, or generation that meets other defined standards, the seller will provide electricity with those attributes. The price required to attract that supply will be dependent on the required attributes or characteristics.

SB 32 only requires that the energy be generated by facilities with a capacity no larger than 3 MW, and that they meet RPS standards. The ratepayer value of various generation products and locations may advantage some technologies over others, but neither categorically limits not requires the technology options with which the market may respond, thus allowing an open and level playing field for innovation.
If the Commission determines that some portion of the procurement should be reserved for a particular electrical product or generator characteristic, including sizes other than 3 MW, the market will reflect the necessary price specific to these requirements.

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.

The Clean Coalition does not see the need for the development of new MPR proxy plants or subsets of such proxies and believe that such development would unnecessarily delay the proceeding and create a potentially ongoing burden for staff. Under our recommended market based approach, no MPR proxy is required, alleviating the necessity for establishing and implementing new MPR methodology.

The Clean Coalition believes there is merit in support for specific generation markets beyond that required under SB 32, however this will be substantially and cost effectively addressed through the application of location and time of delivery price adjustments, and the need for specificity beyond this was not addressed in the enabling legislation.

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.

We have recommended above that the 2009 MPR be the baseline for price discovery, but moving forward the Commission should base any pricing changes on the SB 32 market response. If the market response is robust, we have suggested triggers for price degression. If the market response is not robust, we recommend that the Commission reconvene this proceeding and craft an alternative pricing structure. (We are, however, fairly confident that the market response will be robust if pricing is set at MPR plus TOD plus Locational Benefits). Thus, the SB 32 pricing will, under our recommendations, not be tied to any particular technology (though we recognize that solar PV will very likely be the predominant technology under SB 32, based on recent market response to other programs).

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.

As stated above, the Clean Coalition does <u>not</u> support an auction approach to pricing under SB 32 and we believe this would clearly violate SB 32. The AB 1969 program, the predecessor to SB 32, was a feed-in tariff program, which by definition includes a set price. SB 32 modified section 399.20, which was added to the code by AB 1969. AB 1969's section 399.20 stated: "(d) The tariff shall provide for payment for every kilowatthour of renewable energy output produced at an electric generation facility at the market price as determined by the commission pursuant to Section 399.15 for a period of 10, 15, or 20 years, as authorized by the commission."

This language is almost identical to the new section 399.20(d)(1), which simply lacks the reference to section 399.15:

> The tariff shall provide for payment for every kilowatt hour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to ~~Section 399.15~~ *paragraph (2)* and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.

Accordingly, it seems clear that the Legislature had no intent to change the AB 1969 program into a non-FIT program and the Clean Coalition strongly opposes any such change.

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.

The Clean Coalition strongly opposes using RPS program solicitation to determine market price because very few projects three MW and below have won RPS contracts and even fewer have come online – which is the true criterion for establishing the necessary market price. Simply put, there is no record in the RPS program to provide adequate data for pricing in the SB 32 program.

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

We have provided our pricing recommendations above.

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.

If the Commission rejects our pricing recommendations described above, we strongly recommend that it use instead only pricing data from operational projects. As discussed, there are many executed PPAs at prices that apparently are insufficient to spur financing or construction. Any data used by the Commission to support a pricing approach different from the one we have outlined should come only from operational projects.

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.

We have proposed either a volumetric degression formula for pricing or, if market response is very weak after the first year of the program, based on initial pricing, a reconsideration of the initial pricing formula.

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.

With respect to SB 32's customer indifference requirement (section 399.20(d)(3)), the MPR plus TOD plus locational benefits formula we've recommended will, by definition, leave ratepayers indifferent because these costs will be borne by all ratepayers independent of the existence of any SB 32 projects. The key concept behind SB 32's pricing is that it will leave ratepayers indifferent because it captures the value to ratepayers from these projects. In other words, SB 32 creates a "value-based" feed-in tariff, which is by definition ratepayer indifferent.

MPR is essentially an avoided cost – the cost ratepayers would have paid if not for renewable energy projects priced at MPR. TOD is ratepayer indifferent because it is a time-dependent valuation that applies to all power projects in California. And locational benefits are ratepayer indifferent because they only capture, by definition, costs or savings that would otherwise have been incurred by ratepayers.

FERC has made clear in recent decisions[12] that states have authority to set "multi-tiered" FIT rates under PURPA's avoided cost methodology, if state law requires that utilities procure renewables under, for example, a Renewable Portfolio Standard, and if projects are registered as Qualifying Facilities (which is not a particularly onerous requirement). Our recommended pricing formula will not, however, result in a multi-tiered FIT. Rather, it will create a single FIT that applies to all types of projects. As such, there is even less room for disagreement over federal precedent in this area because the Commission will be setting just one base rate for all SB 32 technologies, with pricing varying by production profile and location of projects due to TOD and locational benefits adders, respectively.

[12] Particularly *FERC Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 (October 21, 2010) and FERC Order Denying Rehearing, 134 FERC ¶ 61,044 (January 20, 2011).*

For pricing in 2012, after the 2011 MPR resolution is released, our recommended pricing formula departs from a traditional calculation of ratepayer indifference – but will very likely still leave ratepayers indifferent to the SB 32 program. This is the case because ratepayer indifference, under recent FERC guidance, needs to be defined based on the avoided costs relevant to the projects at issue. If a state has an RPS, FERC has stated that the avoided costs may be calculated based on the market costs of renewables instead of the default option such as a natural gas power plant. By extension, if a state passes a law calling for 750 MW of distributed generation, as California has done with SB 32, any avoided cost calculation should refer only to 3 MW and below renewable energy projects. Under the volumetric degression formula we have suggested, moreover, ratepayers are protected against windfall profits for developers because the price drops as market interest increases.

15) Please indicate how [your ratepayer indifference] positions have changed, if at all.

The Clean Coalition's position on ratepayer indifference has not changed from our previous briefings in R.08-08-009.

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

The Clean Coalition generally supports the bifurcated approach recommended by staff, with the additional advice letter approach described above to expand the project size cap to 3 MW. The items we have identified as needing immediate attention are: 1) expansion of total program size; 2) expansion of project size eligibility (preferably in immediate advice letter filings or in the interim order); 3) elimination of the customer requirement; 4) contract termination clause modifications (which is happening concurrently to this proceeding for SCE); 5) clarification that AB 1969 and SB 32 projects aren't precluded by an applicant having a CSI or SGIP project on the same property.

We are also anxious to see Rule 21 reforms completed and a reassertion of state jurisdiction over WDG interconnection. However, the Rule 21 Working Group is working on a parallel track on these issues and won't be done until early 2012 at the absolute earliest date. It is, thus, reasonable for this proceeding to wait until the Rule 21 Working Group makes additional progress before it determines the appropriate schedule for addressing interconnection issues in this proceeding. Thus, we agree that interconnection issues should be addressed in Phase II of this track of R.11-05-005.

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.

It appears that the cite to section 399.20(b)(2) is a mistake. The Clean Coalition fully supports requiring the utilities to submit tariff changes and revised contract language in August and we have been working with SCE in reforming their CREST program PPA.

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?

We recommend that proportionate shares be calculated based on average GWh share of the state-wide total.

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

The Clean Coalition agrees that these tariffs should be consolidated.

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

The Clean Coalition agrees that the retail customer requirement should be eliminated before the end of 2011. This should be a simple matter, requiring only that filed advice letters and *pro forma* PPAs reflect this change – as SCE has already proposed in its CREST PPA reform.

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.
21) Parties are asked to comment on this recommendation.

The Clean Coalition agrees that this provision should be addressed in 2012.

SB 32 added subsection (m) to § 399.20. SB 2 1X did not modify subsection (m). Subsection (m) requires that, within 10 days of receipt of a request for a tariff pursuant to this section…the electrical corporation that receives the request shall post (1) a copy of the request on its internet web site and, in addition, (2) the name of city where facility is located. Subsection (m) specifically states that information in the request that is proprietary and confidential, including, but not limited to, address information beyond the name of the city shall be redacted.
This ruling proposes to implement this provision by end of 2011.
22) Parties are asked to comment on this recommendation.

The Clean Coalition agrees that this relatively simple requirement should be implemented by end of 2011. These posting requirements are not crucial to the functioning of the SB 32 program, but because it should be relatively easy to implement, we agree it should be completed in Phase I. We otherwise have no quarrels with the language of SB 32 in this instance.

23) Identify any issues [relevant to POUs and SB 32] 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.

The Clean Coalition recognizes that IOUs must calculate their proportionate share of the statewide total and we recommend that it be calculated proportionately to each IOU's consumption of electricity (GWh) as a share of the state-wide total. We don't see any other issues over which the Commission has jurisdiction that impact POU implementation.

24) Parties are asked to comment on [the tariff request denial] recommendation. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.

The Clean Coalition agrees that this aspect should be addressed in 2012. We don't anticipate that tariff request denials will be an issue in this program, because of its relatively high profile – and particularly not in its early implementation. However, if for some reason it does become an issue there will be time to address the problem in 2012.

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

The Clean Coalition feels that the existing CREST termination language needs to be fixed as soon as possible and we believe that SCE's new pro forma will fix this issue. We also want to ensure that the old language is not somehow carried over into the new SB 32 pro forma.

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

The Clean Coalition agrees that this provision should be addressed in 2012 but feels strongly that it should be addressed and resolved early in 2012, prior to the start of the March 2012 cluster window for WDAT and CAISO interconnection. In the interim, however, we recommend that developers should be able to choose to use Rule 21 or WDAT (there are some situations where WDAT might be superior).

27) Parties are asked to comment on this recommendation [for adjustments for small electric utilities].

The Clean Coalition has no comment at this time.

This ruling proposes not to implement this provision [re revoking any other incentives] by end of 2011. This issue will be addressed at the beginning of 2012.
28) Parties are asked to comment on this recommendation.

The Clean Coalition agrees that this provision should be addressed in 2012.

Respectfully submitted,

TAM HUNT

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Dated: July 21, 2011

Attachment A

The listed parties agree with the following statement with respect to the need for an expedited implementation of SB 32 in 2011:

We agree with the Clean Coalition that the federal tax benefits identified (section 1603 cash grant program and 100% bonus depreciation) weigh heavily in favor of partial SB 32 implementation in 2011. If the Commission is able to expand project size eligibility to 3 MW, up from the current 1.5 MW, we and many other companies would pursue a PPA under the SB 32 program and do our best to achieve the project milestones required to qualify for these programs. In particular, both of these programs have hard project deadlines of January 1, 2012, and having a definite PPA opportunity under the new SB 32 program, before the end of 2011, would help us substantially in meeting these deadlines.

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Title: Director of Business Development

Company: BAP Power Corporation dba Cenergy Power

Name: Marcus da Cunha

Title: Vice President of Development

Company: EcoPlexus, Inc.

Name: Peter Weich

Title: President

Company: Absolutely Solar Inc.

Name: Al Rosen

Title: Director

Company: Absolutely Solar Inc.

Name: John Barnes

Title: President

Company: Solar Land Partners

VERIFICATION

I am an attorney for the Clean Coalition and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing pleading are true.

I declare under penalty of perjury that the foregoing is true and correct. Executed this 21st day of July, 2011, at Santa Barbara, California.

Tam Hunt

Clean Coalition

CERTIFICATE OF SERVICE

I hereby certify that I have served by electronic service a copy of the foregoing CLEAN COALITION OPENING COMMENTS ON ORDER INSTITUTING RULEMAKING on all known interested parties of record in R.11-05-005 included on the service list appended to the original document filed with this Commission. Service by first class U.S. mail has also been provided to those who have not provided an email address.

Dated at Santa Barbara, California, this 21st day of July, 2011.

____

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