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 08-08-009 (Filed August 21, 2008)

CLEAN COALITION OPENING COMMENTS ON PROPOSED DECISION RE SB 32 IMPLEMENTATION

Tam Hunt
Attorney for:
Clean Coalition
16 Palm Ct
Menlo Park, CA 94025
(805) 705 1352

April 9, 2012

CLEAN COALITION OPENING COMMENTS ON PROPOSED DECISION RE SB 32 IMPLEMENTATION

The Clean Coalition respectfully submits these opening comments on SB 32 implementation, pursuant to Rule 14.3 of the California Public Utilities Commission's Rules of Practice and Procedure.

The Clean Coalition is a California-based advocacy group, part of Natural Capitalism Solutions, which is based in Colorado. The Clean Coalition advocates primarily for vigorous feed-in tariffs and "wholesale distributed generation," which is generation that connects primarily to distribution lines close to demand centers. Clean Coalition staff are active in proceedings at the Commission, Air Resources Board, Energy Commission, the California Legislature, Congress, the Federal Energy Regulatory Commission, and in various local governments around California.

Our key points may be summarized succinctly:

- The PD deviates from SB 32 in many significant ways, and errs too much on the side of extreme price hawkishness. This will very likely result in PPAs accepted at unrealistic prices in a "race to unviability," which will delay project deployment, reduce program effectiveness, and may well foster market gaming, consolidation and inefficiencies, ultimately resulting in higher costs for ratepayers
- The Commission should create a program that ensures a viable long-term market and that is eventually accessible to a broad section of the public for projects much smaller than 3 MW – similar to the German model, which has relied primarily on smaller projects to reach their remarkable 23,000 MW of solar capacity and 29,000 MW of wind power capacity
- The Re-MAT allocation schedule and price adjustment triggers should be modified to support effective market price discovery and more timely deployment

- The Commission should use its inherent authority to at least double the SB 32 program size, to 1,000 MW, as it did with the AB 1969 program and in creating the RAM and CSI programs (all under the Commission's inherent authority)
- A program size doubling will allow a significant expansion of the product buckets, which will allow the Re-MAT pricing mechanism to work far more effectively. This will allow a far more effective program, utilizing much of the large technical potential for distributed solar that the recent E3 report for the Commission calculated
- The starting price should be a normalized RAM price, adjusted for the smaller SB 32 program size
- The starting price should also include a 10% locational adder in "hot spots," similar to the pricing adopted by the Commission with respect to the AB 1613 CHP feed-in tariff
- A price floor should be set, at the normalized RAM clearing price, in order to provide the necessary market certainty to "accelerate the market" as SB 32 requires, and to avoid unrealistic pricing trends that will result in excessive project failure rates.
- "Strategically located" should be defined in a clear and predictable manner. Projects should be considered "strategically located" if they comprise less than the minimum coincident load, in the aggregate, on the substation at issue
- Similarly, projects should be deemed deliverable, for resource adequacy eligibility, if they comprise less than the minimum coincident load on the substation

I. Overview

Governor Brown has set a goal of 12,000 MW of distributed generation by 2020. SB 32 is the single most promising mechanism for achieving this ambitious goal – <u>if the program is implemented effectively and the size expanded significantly</u>. The Proposed Decision ("PD"), however, fails to expand the program size from what is an extremely modest <u>15</u>

megawatt increase over the current program size, and fails to recognize that much of the existing program is already allocated, as discussed further below.

More generally, the Clean Coalition is frustrated that this program has not only taken years longer than it should have to be implemented, but has been steadily whittled down from its original intent as an MPR-based feed-in tariff. It's time for California to regain the lead in renewable energy policy and stop fiddling around the edges in a way that further erodes our ability to transform our energy system away from fossil fuels.

The PD violates the intent of SB 32 with its proposed pricing mechanism. With respect to pricing, the PD fails to recognize the tradeoff between project risk and price hawkishness. This is the case because it will create a "race to unviability" due to its heavy pressure on downward prices. This heavy pressure will very likely result in a high level of contract failure, which may not only cause the program to be ineffective but may well foster market gaming, market consolidation and market inefficiencies, that will ultimately result in higher prices for ratepayers as fewer applicants participate and existing projects are delayed or scrapped. Contract failure may result ultimately in higher prices for projects that do eventually come online.

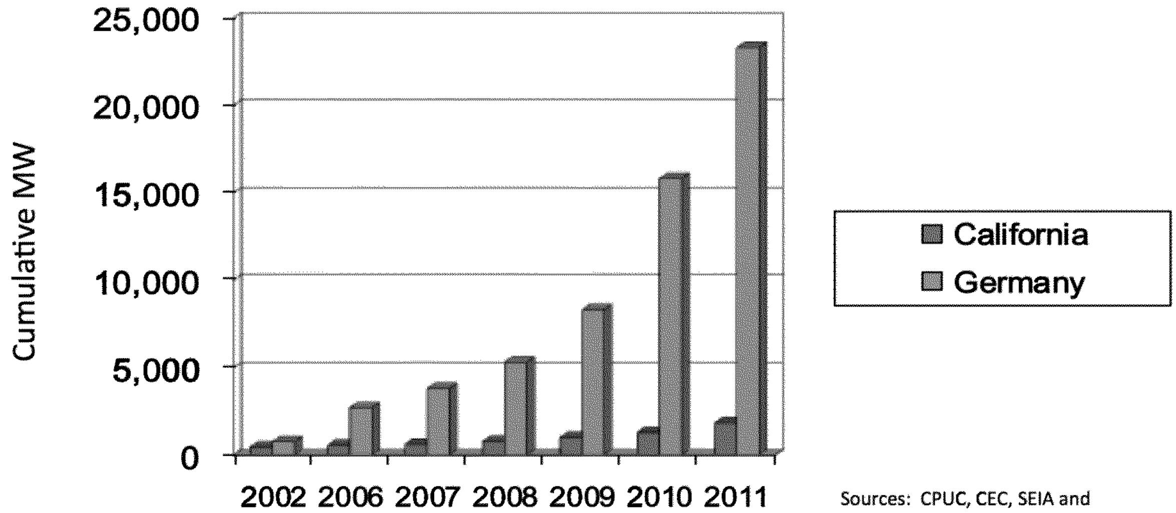
As the 2010 UCLA report for Los Angeles Business Council makes clear (p. 47), feed-in tariffs can be created with very low pricing that may "skim the bottom" of the renewables market for the lowest-priced projects. But this approach will not discover the market price necessary to develop a substantial level of wholesale distributed generation, as the Governor's goal and other state goals envision.

European markets have demonstrated that increased market participation and program scale has consistently led to experienced-based cost reductions that are passed on to ratepayers. These policies have resulted in far lower installed costs than in California despite similar commodity equipment prices. Conversely, unregulated short-term price wars and contract manipulation for consolidation of market share historically depresses market growth, experience-based efficiencies and new entrant innovations. Effective long-term results are dependent upon adequately-scaled, stable and predictable demand and price signals. Instability in both aspects have previously resulted in boom and bust cycles leading to inefficiencies in both cost and market development over time.

If we are to meet the Governor's 12,000 MW goal – and go beyond this goal after 2020 – California must open up its power market to the public far more than it has done so in the last decade. This "broad open market model" has been pursued in highly successful markets like Germany, in which solar, wind and biomass power now provide over 20% of the nation's electricity (which is the world's third largest economy). Germany achieved this incredible transformation in just 15 years, rising from almost no renewable power in 1995. This transformation has also been achieved by implementing power purchase policies (feed-in tariffs) that opened up the market to everyone with roofspace for solar or an open field for wind. Germany has now installed over 15 times California's solar capacity (including the California Solar Initiative, RPS, and other programs), with 70% weaker solar resources, and over nine times the installed wind power capacity!

Moreover, Germany's installed cost of solar is far lower than ours, due in large part to the certainty and effectiveness of their feed-in tariff program (which includes regular price degression, resulting in the substantial price declines we've seen in recent years). Germany's political leadership is now proposing major changes to their highly effective FIT program, but these changes are a result of the resounding success of their program, not failure. Germany brought over 7,000 MW of solar online in both 2010 and 2011, far exceeding expectations. By comparison, California brought 300 MW of solar online in 2010 and 542 MW in 2011.

Figure 1. *Comparing Germany and California solar capacity.*

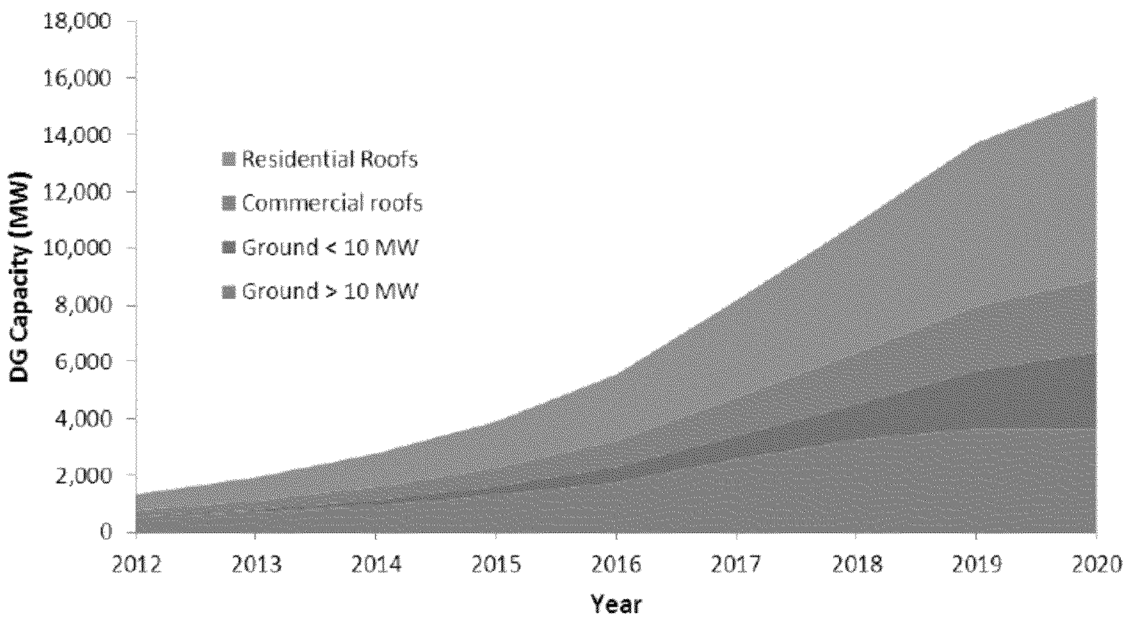


Sources: CPUC, CEC, SEIA and German equivalents.

California can emulate this success – and must emulate this success if we hope to meet our short and long-term renewable energy and climate mitigation goals – but not if policymakers continue on the path we've been on for the last ten years. Our RPS program is finally showing signs of life, after nine years of near stagnation. The Renewable Auction Mechanism (RAM) program, intended for 3-20 megawatt renewable energy projects, is, however, entirely untested because it is a new program and no projects are online yet. Other programs, such as the utility PV programs, designed for 1-20 megawatt PV projects, have some promise but are far too small, even when all programs are combined, to achieve the Governor's goal – or come anywhere close to what Germany has achieved.

The good news is that E3 has recently completed a report for the Commission that details the huge potential for distributed PV, finding a potential of 15,000 megawatts on distribution lines around the state that can be interconnected without upgrades being triggered by exceeding peak load limits. Figure 2 summarizes this report's findings. What is needed now is a policy mechanism to make this huge potential reality – and expanding SB 32, with a viable pricing mechanism, is clearly the most promising route.

Figure 2. *E3 calculated distributed PV potential in CA.*



II. Discussion

A. The PD violates the intent of SB 32 in creating a bidding process

The Commission is attempting to change SB 32, which was clearly intended to be a feed-in tariff, into a quasi-auction or tender program. This directly contradicts the legislative intent behind SB 32.

The PD states (p. 53, emphasis added):

> The market-based pricing methodology adopted today allows customers to realize the benefits of changing market conditions that result in potentially lower costs. In addition, it allows generators to set the market price through the <u>bidding process</u>, which theoretically will ensure the price is neither too high nor too low but, instead, will be reasonable to cover the generator's costs and encourage participation in the market.

SB 32 did not create a "bidding process," it created a program tied to the Market Price Referent, which is a fixed price. SB 2 1X eliminated only the reference to Public Utilities Code section 399.15 but did not change the language in SB 32 otherwise. As such, the intent of SB 32 was clear at the time of its enactment and this intent did not change with the passage of SB 2 1X.

The Clean Coalition has advocated a fixed-price tariff with volumetric degression in previous comments. A fixed-price with volumetric degression matches the clear intent of SB 32 but also mirrors the highly successful FIT programs around the world. We can, however, accept the PD's proposed price mechanism <u>with some significant changes</u>.

We describe below how we believe the PD could be modified, with just a few important tweaks, to comply with SB 32 and to create an effective FIT with volumetric degression.

B. Policy guidelines

The PD's enumeration and prioritization of policy guidelines (p. 18) is contrary to SB 32 and to state policy regarding renewables. There is no point in minimizing costs if the program fails. Moreover, SB 32 requires ratepayer indifference, which means not only that ratepayers should not be undercharged but also that ratepayers not receive uncompensated value from SB 32 projects.

The Clean Coalition recommends the following guidelines and our comments are informed by these guidelines: 1) SB 32 should create an effective and cost-effective FIT that results in successful on-time deployment (18 months) and avoids excessive project failure; 2) an effective FIT must provide reasonable pricing that doesn't encourage a race to unviability and thus high rates of contract failure; 3) this new program should form the basis for a much larger program, which will require either Commission action under its inherent authority or new legislation to expand the program size; 4) this new program should also from the basis for an expanded program that can work for projects much smaller than 3 MW, akin to the German model, as the bill's author has stated publicly to be her intent.

C. Program size should be doubled

We note that the PD's implementation of SB 32 results, under its own terms, in a very small increase in program size, from 478.4 MW to 493.6 MW – just 15 MW. <u>We also note that much of the available capacity has already been awarded in some manner under the existing AB 1969 program</u>. PG&E's general customer queue for AB 1969 is fully allocated and SCE's queue was filled up around the middle of 2011 (though only 75 MW of projects in the queue have signed PPAs with SCE).[1] SDG&E's website lists only 20.5 MW of unsubscribed capacity. In sum, it seems that all but the approximately 100 MW still available in PG&E's water and wastewater treatment plant capacity, and 20 MW available in SDG&E territory, has been subscribed in some manner.

<u>This means that a grand total of about 135 MW may be available to new market entrants under SB 32's investor-owned utility component.</u>

We note also that the PD is mistaken when it states (p. 69) that it expands AB 1969 from "250 MW to 750 MW." To the contrary, as stated above, the PD barely increases the IOU program size from 478.4 MW to 493.6 MW and actually decreases the SCE allocation, when compared to the existing program. Other parts of the decision recognize this, but p. 69, where program size is discussed, suggests something different.

The Clean Coalition previously argued that the Commission should, under its inherent authority, expand the program size substantially, going beyond SB 32's language. The PD ignores the Commission's inherent authority and states that expanding the program size beyond 750 MW "cannot be reached" (p. 69), without further elaboration.

SB 32 does not, however, prevent the Commission from increasing the program size under its inherent authority. Nothing in the statute states that its suggested 750 MW cap cannot be expanded by the Commission. (P.U. Code section 399.20(f))

[1] Some of SCE's queue may well disappear if they don't receive Fast Track of System
32 is implemented, making additional capacity available for SB 32. However, it is not clea
projects in the SCE queue have a legal right to remain in the queue and obtain a PPA un
pricing, in which case this capacity will be taken away from SB 32, or will be forced
32 program goes live.

The Commission has already done exactly what we recommend here when it implemented AB 1969. D.07-07-027 almost doubled (p. 41) the statutorily-prescribed program size from 250 MW to 478.4 MW (250 MW for water and wastewater agencies and 228.4 MW for other customers). We seek a similar determination here, recognizing that the CREST program has already consumed much of the 493.6 MW proposed program size for the IOUs, and we strongly urge the Commission to reconsider this key issue in the PD.

We note that the Commission has also exercised its inherent authority in creating the 1,000 MW RAM program (D.10-12-048) and the 3,000 MW CSI program (D.06-01-024, which was passed three months before SB 1 became law, codifying much that was in the decision). We are asking that the Commission take a similar approach with respect to SB 32 and use its inherent authority to expand the program to the point where it will make a real difference in meeting state goals.

D. Pricing concerns

1. Product bucket sizes for pricing changes should be expanded significantly

The PD's monthly price adjustment mechanism (p. 46, *et seq.*) is excessively sensitive relative to project size and as such does not provide for adequate participation or sample size to reasonably determine market price. Under the proposed Re-MAT, a downward price adjustment will be triggered even if one or two contracts are accepted at the offered price in each utility's applicable product category ("bucket"). This will very likely continue the exact same "race to unviability" that we have seen in California's existing solicitation and auction programs, because developers will be incentivized to obtain an SB 32 contract at prices below what are actually feasible or risk losing the opportunity to obtain a PPA at all. This mechanism will, accordingly, either keep SB 32 prices at the same level, or lower, the following month. California will, as a consequence, have even more "vaporware" contracts but very few actual projects coming online.

This race to unviability will be strongly exacerbated by the extremely small program size that the PD creates, as discussed above.

In addition, the PD's PPA offer rate (one or two a month per bucket per utility) is also far too slow a pace for project development under this program, given the intent of SB 32 to act as an RPS alternative for projects 3 MW and less and "in a manner that accelerates" this market (section 399.29(e)). This incremental schedule ensures that allocation will not be completed for at least another year beyond the initial implementation of legislation adopted nearly three years ago.

We recommend instead that at least six projects or 18 megawatts (with exceptions for SDG&E due to smaller bucket sizes), whichever is larger, be the price degression trigger. This will ensure not only that degression sensitivity is more reasonable and predictable, but also ensure that more projects are awarded PPAs and proceed without undue delay (rather than one or two PPAs per month per product category per utility, the approach recommended in the PD). If the market response is insufficient to meet this capacity, no price degression should occur.

For price increases, we recommend that a price increase take place when projects equivalent to less than half of the 18 MW bucket accept a PPA in a one-month period.

If PPAs are accepted that amount to between nine and 18 MW (meeting 50-99% of demand), in each one-month window, this is a strong indication of the market's lower price limit and the price should, under our proposal, remain constant.

2. The PD does not comply with SB 32's intent to set a stable price

SB 32, as enacted, required Market Price Referent pricing, and this is not disputed by the Commission or parties. SB 2 1x modified section 399.20(d) by "removing the cross reference to now repealed 399.15," the code section that prescribed the methodology for the Market Price Referent, as the PD states (p. 15). The rest of SB 32's language was unchanged by SB 2 1x and it is clear that the Legislature did not change the intent behind SB 32 when it passed SB 2 1x. Rather, the omission of the reference to section 399.15 was simply to harmonize SB 32 with the omission of that section from the code.

Accordingly, the clear intent of the Legislature was to enact a feed-in tariff at the Market Price Referent and, per section 399.20(e), "in a manner that accelerates the deployment of renewable energy resources." The PD, to the contrary, sets a starting price below the 2011 MPR and includes a mechanism that all but guarantees that the starting price will drop even further. This is clearly contrary to the intent of SB 32.

Despite the original and clear intent of SB 32, the Clean Coalition feels that a <u>starting price comprised of a normalized RAM clearing price, plus a locational adder for projects located in "hot spots," is compliant with SB 32</u>. We flesh out these recommendations in the following sections.

3. The PD's starting price is too low to be viable for solar projects

The PD's starting price of 8.923 c/kWh is too low for solar projects in the SB 32 size range to be viable, even with extremely aggressive pricing. We've modeled a 3 MW solar project, ground-mounted, with single-axis tracking, and $1/watt panels, a 25% net Time of Delivery boost (which adjusts the PPA price to 11.16 c/kWh), and a total system price of $2.79/watt dc.[2] Even at this very aggressive pricing (no projects have yet been built at this pricing level), the IRR on this project is only about 6.8 percent and Net Present Value is <u>negative</u> $119,000 (with a discount rate of only 5% nominal).

This is clearly not a good investment and no developers <u>hoping to obtain financing</u> will accept a PPA at this price.

Here is the summary from NREL's System Advisor Model (SAM), under the above parameters:

---

[2] To demonstrate that this pricing is extremely aggressive, consider that the recently released SEIA *Solar Market Insight* report shows that pricing for all utility-scale solar projects in the entire country, which includes m[...] that are far cheaper to construct than California projects, as well as projects far larger than 3 MW, was $[...] dc in the 4th quarter of 2011 (p. 41, Figure 2), http://www.seia.org/cs/research/solarinsight.

Metric	Base
Net Annual Energy	6,385,334 kW
PPA price	11.16 ¢/kWh
LCOE Nominal	11.16 ¢/kWh
LCOE Real	9.46 ¢/kWh
After-tax IRR	6.78 %
Pre-tax min DSCR	17976931348
After-tax NPV	$ -119,448.05
PPA price escalation	0.00 %
Debt Fraction	0.00 %
DC-to-AC Capacity Factor	24.3 %
First year kWhac/kWdc	2,129
System Performance Factor	0.75
Total Land Area	23.82 acres

4. The Commission should normalize the RAM clearing price for 3 MW projects

In order to provide viable pricing for solar and other renewables, and to comply with SB 32, the Commission should, at the least, provide a normalized RAM clearing price as the starting price for SB 32 projects.

The PD's proposed pricing structure, starting at 8.923 c/kWh (or lower, due to negotiations prior to finalization of RAM contracts), results in SB 32 pricing significantly <u>below</u> the current Market Price Referent (the proxy cost for power from a new 500 MW natural gas plant with some minimal environmental adders) for a 20-year contract ($0.09376 for projects coming online in 2013 and $0.09755 for 2014 projects). Given the intent of SB 32 and the analysis in the PD itself, this would be a perverse result.

The PD itself acknowledges that the RAM program is "not the same" as SB 32 (p. 40):

> The market segments covered by RAM and § 399.20, however, are not the same. RAM covers renewable projects sized up to 20 MW. The § 399.20 FiT Program covers renewable projects sized up to 3 MW. … Nevertheless,

> while not identical, the RAM Program presents the closest comparison and, as such, we find it reasonable to define Re-MAT, which includes the market adjustment mechanism, as an avoided cost, as required under federal law.

We strongly disagree that RAM pricing should, without adders or normalization for size, be the basis for the SB 32 starting price. This is the case because, as we have argued to the Commission before, there are zero RAM projects constructed, and none will be completed for a year or more. It makes no sense to base market pricing for SB 32, without additional adders, on a completely untested program. Also, SB 32 requires ratepayer indifference, which means not only that ratepayers mustn't be made to pay more for SB 32 projects, but also that developers must be compensated for benefits ratepayers receive. If ratepayers receive benefits such as local capacity or avoided distribution line upgrades due to SB 32 projects, they are not indifferent to this new program unless projects are compensated for these benefits.

The recent E3 report commissioned by the CPUC ("Technical Potential for Local Distributed Photovoltaics in California"), on the technical potential for local solar PV, PV costs data for various size segments, based on confidential information (p. 47). Even though the pricing data is well out of date (it's from 2010), due to dramatic price reductions in the last two years, demonstrated in SEIA's *Solar Market Insight* report, the E3 report still provides an appropriate basis for normalizing the RAM price for SB 32, by looking to the ratios between size categories. The average ground-mounted 10-20 MW projects price in the E3 report is $6,219 and for 1-3 MW it's $7,138. This results in an appropriate normalization factor of 14.8% for the SB 32 starting price.

As such, the 8.923 c/kWh suggested SB 32 starting price should be normalized upwards 14.8% to $0.1025. With a 25% net Time of Delivery boost (raising the PPA price to 12.8 c/kWh), this results in the following economics for a 3 MW solar ground-mounted project, under the same assumptions as above:

Metric	Base
Net Annual Energy	6,385,334 kW
PPA price	12.80 ¢/kWh
LCOE Nominal	12.80 ¢/kWh
LCOE Real	10.84 ¢/kWh
After-tax IRR	8.57 %
Pre-tax min DSCR	17976931348
After-tax NPV	$ 569,046.14
PPA price escalation	0.00 %
Debt Fraction	0.00 %
DC-to-AC Capacity Factor	24.3 %
First year kWhac/kWdc	2,129
System Performance Factor	0.75
Total Land Area	23.82 acres

5. A locational adder should be included in the starting price

The PPA price should also include a locational adder, as the staff proposal recommended. We recommend, however, a different methodology than the staff proposal. The staff proposal recommended a locational adder for projects located in areas that would lead to avoided distribution grid upgrades, but the PD rejected this recommendation in favor of the adjustable market price concept (Re-MAT). The PD states that additional work is required to include a locational adder (p. 38). However, considering the fact that the locational adder would, for many projects, be a very substantial part of the PPA price under the staff proposal, and considering the economics we've shown above for projects at the pricing suggested in the PD, it is far more preferable that the Commission conduct any additional work on the locational adder, that it feels is required, <u>before</u> adopting a final decision.

However, there is a middle-ground solution that can avoid additional delays while also including, as SB 32 requires, a locational adder. The Clean Coalition feels that the Re-MAT is a viable pricing mechanism, in line with SB 32's directives, <u>if it also includes a</u>

locational adder in the starting price, which will then adjust based on the PD's ratcheting mechanisms. SB 32 requires (section 399.20(e)) that "avoided transmission and distribution improvements" be included in the PPA price. SB 32 also requires ratepayer indifference, which means not only that customers can't be charged more than the status quo for SB 32 projects, but also that developers must be compensated for the value received from SB 32 projects – including locational benefits.

E3 quantified the locational benefits provided by wholesale DG and the starting price should ideally include the value calculated by E3. However, given the pushback by some parties on the E3 analysis, and given the Commission's current hesitation on this issue, we feel that the 10% locational adder provided to CHP projects under AB 1613 (D.11-04-033), should be adopted in the present case. Rather than a 10% adder based on local resource adequacy requirements, however, as was the case in D.11-04-033, we recommend a 10% adder be provided for projects located in the hot spots identified by E3.

In sum, we recommend that a 10% locational adder be included in the starting price for projects located in the "hot spots" identified by E3. If we add the 10% locational adder to the starting price, plus the normalization factor discussed above, we obtain a total starting price of 11.275 c/kWh (adjusted to 14.10 c/kWh based on TOD), but only for projects located in hot spots. This price results in the following economics, which we feel is suitable to "accelerate the deployment of renewable energy resources," as is required by section 399.29)(e), while also respecting ratepayer indifference:

Metric	Base
Net Annual Energy	6,385,334 kWl
PPA price	14.10 ¢/kWh
LCOE Nominal	14.10 ¢/kWh
LCOE Real	11.94 ¢/kWh
After-tax IRR	9.90 %
Pre-tax min DSCR	17976931348
After-tax NPV	$ 1,114,585.8
PPA price escalation	0.00 %
Debt Fraction	0.00 %
DC-to-AC Capacity Factor	24.3 %
First year kWhac/kWdc	2,129
System Performance Factor	0.75
Total Land Area	23.82 acres

A 9.9% IRR is a reasonable return and will accelerate the distributed generation market in line with SB 32's directive.

E. A 25-year contract option should be added

We recommend that the Commission add a 25-year contract term, providing additional value to ratepayers and developers. This has historically been an option for renewable energy projects and we see no reason that the Commission shouldn't include it as an option for SB 32 projects.

F. Price floor

To avoid the "race to unviability" and risking program failure as well as project failure, the PD should also include a price floor. A price floor will provide longer-term market certainty that a project can be developed and obtain viable pricing. Certainty is the key feature of successful markets, no matter what type of market is at issue. A price floor provides clear signals to the market to invest and participate, ensuring sufficient attraction of new applicants in the queue to avoid triggering price increases. By avoiding unviable pricing, as would be the case under the PD's pricing mechanism, ratepayers will very likely save money through an effective program instead of one that leads to many projects failing from a race to unviability.

The price floor should be the normalized RAM clearing price that adjusts prices from the 20 MW maximum size for RAM projects to the 3 MW maximum size for SB 32, as discussed above. A price floor will provide the market certainty required for this program to be effective and cost-effective. A normalized RAM price floor is fully compliant with the wide latitude provided under federal law for states to set avoided costs.

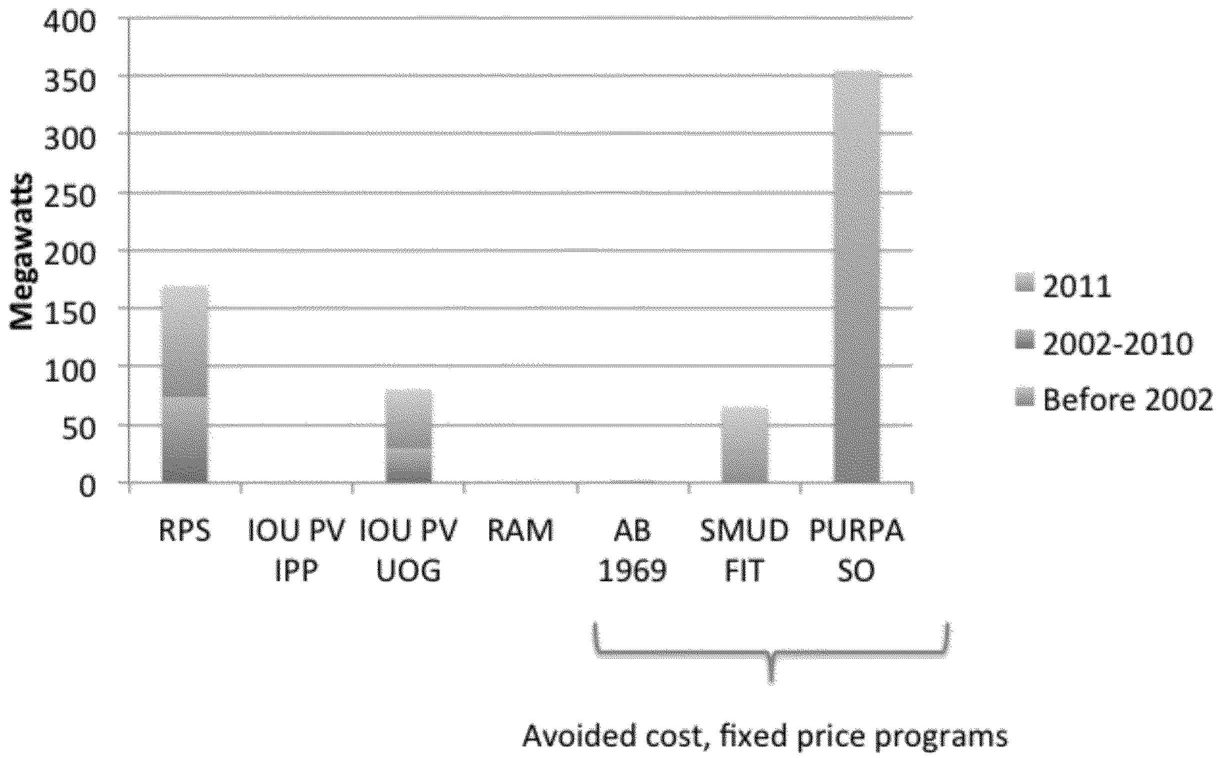
It is telling (see Figure 3) that the most effective program so far for wholesale distributed PV appears to be the UOG portion of the utilities' PV programs – which were pre-approved for reasonableness at a specific cost per kilowatt hour, at almost three times the price suggested for the SB 32 starting price in the PD (about 24 c/kWh for PG&E and 26 c/kWh for SCE). We don't have detailed pricing information yet for completed projects under the IOU PV programs, and actual prices are surely much lower than these pre-approved costs, but the point remains that these programs have been effective in large part because the IOUs were granted cost recovery up to these pre-approved pricing levels.

It is also telling that by far the most successful program for solar in the last thirty years was the PURPA Standard Offer feed-in tariff (the world's first feed-in tariff) program, with avoided cost pricing, which resulted in 354 MW of concentrating solar facilities being constructed in the 1980s and early 1990s, as well as the large majority of wind power capacity, geothermal and biopower that is still online today in California.[3]

---

[3] This article provides more of PURPA's history in California: http://www.renewableenergyworld.com/rea/news/article/2010/06/an-embarrassment-of-riches.

Figure 3. *Comparing various California programs for solar (Source: various).*



We seek a similarly effective pricing mechanism for SB 32, while respecting the ratepayer indifference requirement, and the PD does not provide this. The price floor we have suggested, while still far below the pre-approved cost for the UOG PV programs, would provide sufficient market certainty for SB 32 to be effective and cost-effective.

G. "Strategically located" must be re-defined

The PD's definition of "strategically located" (p. 62) requires that SB 32 projects interconnect on the distribution grid and "must be sited near load, meaning not in an area with such low load that interconnection of the proposed generation would require utilization of the transmission system and new transmission infrastructure." This latter requirement is a fatal flaw in the PD. It is overly vague in the discretion it provides to utilities to deny projects, because some utilities, SCE in particular, are concluding that almost all distribution level projects have transmission grid impacts. Under the PD's definition of "strategically located," most of SCE territory would be ineligible for SB 32 contracts. Similarly, some utilities (PG&E, in particular) are increasingly requiring developers to pay for safety upgrades on the transmission grid, like direct transfer trips, which would, under the PD's definition of "strategically located," result in these projects becoming ineligible.

The test for "strategically located" should be a bright-line test, instead of being vague and left to utility discretion. The Clean Coalition strongly recommends that "strategically located" be defined to mean that SB 32 projects must interconnect to the distribution grid <u>and</u> must comprise, in the aggregate with any other projects, 100% or less of the minimum <u>coincident</u> substation load (for solar, this means 10 AM to 3 PM). This is also our recommended test for a project being deemed deliverable, for resource adequacy purposes, as discussed in the next section.

Moreover, the PD's suggestion that "strategically located" be interpreted to mean that the project must not rely on "the transmission system or new transmission infrastructure" contradicts the PD's recommendations on deliverability. That is, if an SB 32 project seeks deliverability in order to qualify for the higher TOD rates, it will, by definition, be relying on transmission because deliverability requires transmission access and often requires transmission upgrades.

Last, the PD's suggestion that developers may use the IOU Interconnection Maps to "locate sites that have a low likelihood of transmission impacts" is not possible. The IOU maps have no data that will help developers determine potential transmission impacts, based on the way that, for example, SCE, is determining transmission impacts. This issue is a substantial obstacle to SCE's CREST queue at this time and the PD's suggestions on interpreting "strategically located" do nothing to resolve this problem.

H. SB 32 projects that are below the minimum substation load should be deemed deliverable

The Clean Coalition agrees with the PD that "full commercial deliverability status should not be a condition precedent for any generator seeking a contract…" (P. 51). The PD does, however, require applicants to seek deliverability in order to receive TOD pricing, and we disagree with this aspect of the PD.

The difference in TOD payments is likely to be substantial, if the PPA already submitted by the IOUs is indicative. The joint IOU proposed PPA submitted in this docket on Feb. 15 shows, for example, about half the on-peak TOD factor, for SCE, for energy only projects. This could amount to as much as a 1-1.5 c/kWh difference in PPA pricing, which has a very substantial impact on the economics of 3 MW projects.

Moreover, applying for deliverability will increase the cost of project development significantly for SB 32 projects, and these costs are passed on to ratepayers in the required PPA rate.

CAISO and the Commission are currently working on a system of allocated deliverability that would provide deliverability to some projects at no cost. However, we recommend that the Commission deem SB 32 projects deliverable, for Resource Adequacy purposes (an area that is is under Commission jurisdiction), if a project meets the criteria for "strategically located," that is, it comprises 100% minimum load or less, in the aggregate with other projects, on the substation at issue. .

It is extremely burdensome to require SB 32 projects to have to go through a two-year deliverability study and additional time for transmission upgrades, plus a $10,000 deliverability study application fee, plus a $20,000 per MW security posting, in order to obtain what has been the historically standard TOD pricing under SB 32. These fees are all additional to the already-substantial fees the PD would require for the SB 32 application, and existing interconnection fees, not to mention land control fees and other development fees.

I. The project size cap should be in AC

The Commission should clarify if the nameplate capacity referred to on page 58 is AC or DC. We recommend AC because this is the amount of power actually sent to the grid.

J. Daisy chaining and aggregation to reach the 3 MW size limit

The Clean Coalition supports the PD's suggestion that projects on the same property or contiguous to another SB 32 property should be disallowed from obtaining a PPA. However, we are very concerned by the PD's additional language (p. 59): "This provision shall also give utilities the authority to deny a tariff request pursuant to § 399.20(n) if the project appears to be part of a larger overall installation by the same company or consortium in the same general location." This authority is far too broad and undefined. It opens up utility discretion to deny a contract without sufficient guidance from the Commission. We feel that disallowing projects on the same or contiguous properties is sufficient to prevent daisy chaining.

The PD does allow contesting utility determinations under "standard complaint procedures," but history has shown these procedures to be inadequate and we have no faith that they are up to the task here.

We also recommend that the PD be revised to allow for aggregation of projects that are less than 3 MW in order to reach 3 MW, whether or not those projects are on contiguous parcels. This will allow entities that have different parcels under control already, but not sufficient with each property to reach 3 MW, to do so through aggregation.

K. Project viability criteria should be modified

To avoid speculation, developers should have to post a $20/kW security deposit six months after obtaining a PPA. When combined with other project viability criteria, the program will have numerous protections ensuring that only serious developers may obtain PPAs.

Also, viability criteria should be modified to allow for developers who don't construct and operate projects – what is known as a "flip model," which is increasingly common. These entities develop an asset by permitting, interconnecting and obtaining a PPA for a project before selling the project. The viability criteria should allow developers in this category to qualify under the experience criterion, regardless of whether they have actually seen a project through construction.

The PD's use of the term "bid" should be removed because SB 32 created a feed-in tariff, not an auction system.

L. Transitioning the AB 1969 queue to SB 32

The PD fails to describe how existing AB 1969 queued projects will be treated under the new SB 32 program. We recommend that any projects in the AB 1969 queue be allowed to seek an SB 32 contract if they haven't already signed an AB 1969 contract. For example, SCE's CREST queue is filled but only about 70 MW have signed PPAs at this time. Developers who have not yet signed a PPA should be able to transition to the SB 32 queue if they meet the required criteria for SB 32. This transition should preserve the queue positions held under the AB 1969 program.

III. Errata

- P. 6: remove "of" between "address some" and "interconnection issues" in last paragraph
- P. 33: missing "to" between "can work" and "stimulate market demand" in second to last paragraph
- P. 44: "either" and "or too high" at the end of the first paragraph should be removed because it doesn't make sense that the price would be "too high" if no contracts were entered into
- P. 45: add "at" between "after" and "least" at the start of the last paragraph
- P. 45: remove "for" between "contract" and "at" at the end of the last paragraph
- P. 54: add "a" between "must be read" and "consistent" in the second to last paragraph
- P. 59: add "in" between "forth" and "the Commission's" at the end of the second to last paragraph
- P. 62: "criteria" should be "criterion"
- P. 70: "additional cap of 250 MW" in the middle of the page should be "additional cap of 750 MW"
- P. 70: "Joint Solar" should be "Joint Solar Parties". The same error occurs twice on p. 79.
- P. 99: "this" on the first line should be "the".

Respectfully submitted,

TAM HUNT

Attorney for:
Clean Coalition
2 Palo Alto Square
3000 El Camino Real, Suite 500
Palo Alto, CA 94306
(805) 705-1352

Dated: April 9, 2012