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 REPLY COMMENTS ON

SB 32 STAFF PROPOSAL

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SB 32 STAFF PROPOSAL

The Clean Coalition respectfully submits these reply comments on the SB 32 staff proposal pursuant to the Administrative Law Judge's Ruling dated October 13, 2011.

The Clean Coalition is a California-based advocacy group, part of Natural Capitalism Solutions, a non-profit entity based in Colorado. The Clean Coalition advocates primarily for policies and programs that enable the "wholesale distributed generation" market segment, which is generation that connects to the distribution grid for local use. The Clean Coalition is active in proceedings in many regulatory venues, including the Commission, Air Resources Board, and the Energy Commission in California; the Federal Energy Regulatory Commission; and in other state and local jurisdictions across the country.

Preamble

The diverse opening comments on the Staff Proposal are not only indicative of widely divergent opinions on applicable law, but also revealed systemic misinterpretation of the Staff Proposal and the core reasoning underlying the Proposal's main provisions.

Before providing detailed response to the opening comments of other Parties, the Clean Coalition offers the following concepts and conclusions of law to interpret the foundation underlying the Staff Proposal and frame the treatment of Parties' input when drafting the decision implementing SB32.

Commission scope of authority and statutory directive

- 399.20 instructs the Commission to develop a methodology to determine the "market price" on which the FIT contract payments are based. The key point of law is that the Commission is given authority to define "market price" within the context and constraints of the market as defined by the statute: 750 MW of renewable energy projects each of which is no larger than 3 MW

- The Commission specifically is not required to adhere to previous assumptions or methodologies for how a "market price" is determined and California law does not explicitly define the term "market price".
- Because FIT contract payments are explicitly an administratively-determined payment for wholesale sale of electricity, the rate must also conform to PURPA with the parameters as clarified by FERC.
- While the latest FERC guidance provides general parameters for determining avoided cost, there are no directives on the specific methodology and the state Commission is given broad authority to define the applicable avoided cost within the parameters of state mandated procurement obligations
- Because 399.20 imposes an obligation on utilities to procure 750 MW of renewable energy in projects no larger than 3 MW, the Commission may determine a distinct avoided cost for this "market segment" that is independent of any other avoided cost determinations made for other procurement obligations.
- Thus, in designing the FIT payments for 399.20, the Commission may and will establish new methodologies and determinations for market price and avoided cost.

Market Price

- Several Parties claim, erroneously, that a market price can only be determined/discovered through a competitive bidding process where the competitive attribute of the bid is the sale price.
  - Such solicitations / reverse auctions are structured such that sellers offer a price and the buyer decides which price to accept. The price at which the buyer purchases the desired capacity is the market price. However, such

solicitations are by no means the only possible or valid mechanism for determining market price.

- A standard offer with adjusting prices is an equally valid mechanism. In this structure, the buyer offers a price that the sellers decide whether to accept. The price at which the desired quantity is sold is an equally valid market price.
- Because 399.20 explicitly requires a standard offer construct with an administratively set price, the Staff Proposal represents an appropriate mechanism for determining a market price.
- To achieve the optimal outcome in terms of appropriate costs, the policy design objectives are to set the starting price and price adjustments in such a way as to reach the market price deterministically, quickly and transparently.
- Thus, the exact methodology for determining the starting price is relatively unimportant as long as the result is not blatantly too high or too low. The methodology for determining the starting base price does not itself need to be justified to a "market price" standard, because the adjustment mechanisms provide market price discovery.

PURPA avoided cost

- The applicable avoided cost for procurement under 399.20 is the total of all the costs incurred by the utility to procure the marginal unit of electricity in a renewable energy project up to 3 MW in size where the avoided cost is further differentiated by the generation profiles defined in the statute.
- Because no other procurement programs have specifically determined avoided cost for this class of procurement, the methodology used to determine the FIT payments in 399.20 becomes the avoided cost determination. With the additional requirement of "ratepayer indifference" mandated in 399.20, it is ensured that the FIT rate closely reflects current market conditions. No separate hearings/proceedings/rulings are necessary in order determine avoided cost for the purposes of 399.20.

- Avoided cost does not equal the market price that the sellers are willing to accept for the generated energy.
- 399.20 instructs the Commission to determine the value of other avoided costs and FERC directives explicitly authorize the addition of locational and environmental benefits in the calculation of avoided cost.
- The "customer indifference" provision of 399.20 requires that sellers be compensated for the avoided costs.

Primary Comments Summary

Pricing

TURN

- The Clean Coalition agrees with TURN that the established Market Price Referent is a more appropriate base price for SB 32 than the RAM clearing price, but as we wrote in opening comments on the staff proposal we can also accept using the RAM clearing price as the base price
- We strongly disagree, however, with TURN's suggestion that SB 32 projects should, if RAM pricing is used in SB 32, be considered a subset of the RAM program capacity, and thus count against that 1,000 MW program. The RAM pricing is the starting point for avoided cost, but not the actual avoided cost, and there is no precedent for tying the avoided cost calculation to actual avoidance of specific procurement.
- We disagree with TURN's objections to including a transmission cost adder to normalize the RAM clearing price for SB 32. TURN seems to misunderstand the purpose of the transmission cost adder in normalizing the RAM clearing price.
- We also disagree with TURN's statement: "If locational adders are going to be applied, the Commission must guarantee that the savings associated with deferred capital investments will flow through to ratepayers." Neither federal law nor FERC precedent require any guarantee by the Commission of ratepayer

savings. Rather, the Commission must make its best effort to calculate the accurate avoided cost. The staff proposal generally strikes the correct balance between ensuring that ratepayers are not overpaying or underpaying for SB 32 projects.

- TURN also states: "An automatic price adjustment due to program subscription levels – whether based on a percentage change or an absolute $/MWh change – cannot correlate with actual market price changes." As explained in the Preamble of these comments, the automatic price adjustment mechanism is the primary means to discover the market price within the market segment of this program.
- TURN also recommends that only one RAM clearing price be set for each utility (for the category with the most contracts). This recommendation is antithetical to SB 32 and FERC precedent in that it would ignore the key differences between the three categories explicitly enumerated by SB 32: 1) peaking as available; 2) non-peaking as available; 3) baseload.

DRA

- DRA states that it continues to support its Net Surplus Compensation pricing proposal from its August 26, 2011, comments (DRA Opening Comments, p. 1). The Clean Coalition previously addressed why this proposal is entirely inappropriate for SB 32 pricing, under the Commission's own recent guidance with respect to the existing AB 1969 feed-in tariff. In other words, DRA is seeking to re-litigate issues that have very recently been resolved by the Commission.
- DRA objects to E3's locational adder proposal but does not rebut E3's analysis on its merits in any way. This is not sufficient for sound policymaking. Rather, if DRA disagrees with E3's calculation of the locational adder, and thus the calculated ratepayer benefit from SB 32 projects, it should address the merits.

PG&E

- PG&E objects to the staff proposal of providing a locational adder for non-peaking resources. PG&E is misinterpreting the relevant SB 32 language and non-peaking facilities should, under the terms of SB 32, also receive a locational adder.

- PG&E argues that a single statewide RAM clearing price should be used as the SB 32 base price. The Commission should reject this recommendation because renewable resource profiles vary markedly between IOU service territories.
- PG&E also argues that "the Commission should expressly provide the IOUs a procedural mechanism to challenge the FIT pricing before being required to execute FIT contracts, similar to the advice letter process adopted for the RAM Program." This concern is unfounded, however, because RAM contracts are already limited with respect to reasonableness by the very advice letter process PG&E mentions.
- PG&E discusses a number of objections to E3's proposed avoided transmission cost and locational adder. PG&E misunderstands that the reason an avoided transmission cost is included is because the RAM clearing price won't otherwise include the ratepayer transmission cost (if the RAM contract at issue is interconnected to transmission instead of distribution).
- PG&E raises a concern that with no limits on how many SB 32 projects may be located in each hot spot, more projects than are necessary for that hot spot may be located there, resulting in higher cumulative interconnection costs along with the locational adder paid to those developers for up to 20 years. The Clean Coalition argues that this very likely would not happen under our modified proposal to provide a graduated locational adder to all SB 32 projects, depending on location. We suggest in these reply comments an additional means for avoiding the issue PG&E raises: each utility should provide a cumulative MW limit for each hot spot, beyond which that hot spot ceases to be a hot spot.

SCE

- SCE's method for determining the starting price in their MP FiT proposal should be rejected for exactly the same reason that DRA's proposal should be rejected: it is contrary to recent on-point Commission precedent in D.11-06-016. The Commission has in that decision very recently rejected short-term pricing as inappropriate for setting long-term contract pricing. The Clean Coalition could support many features of SCE's MP FiT proposal if the starting price were changed to reflect a more appropriate market price for SB 32 projects.
- SCE also objects to the staff proposed methodology, arguing that prices will be too high. To the contrary, SB 32's ratepayer indifference provision requires, as we have noted previously, that ratepayers not only do not overpay but also that they do not underpay for value received. In ignoring locational benefits, the MPR has never captured full ratepayer value and thus is not a relevant comparison point for ratepayer indifference.
- SCE argues, with respect to calculating avoided costs under recent FERC precedent, that "The Clarification Order makes clear that a state must consider all resources available to meet the particular portfolio standard." SCE is mistaken, however, in that FERC does not limit its ruling to renewable portfolio standard laws. Rather, FERC stated (FERC Clarification Order, Para. 27, emphasis added) that "just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration."
- SB 32 is an "obligation imposed by the state" that requires utilities to procure at least 750 MW of 3 MW and below renewable energy projects. Accordingly, the staff proposal to consider RAM contracts normalized for the 3 MW and below market is entirely in keeping with this recent FERC precedent. The Commission need not consider the broader RPS program, let alone non-renewable procurement, as SCE also argues.
- SCE also raises concerns about the transmission cost component of the staff's

avoided cost calculation, arguing that no evidence is presented to justify this as an avoided cost. SCE misses the point that the transmission component is included, as the staff proposal states, in order to normalize the RAM clearing price contract for distribution-interconnected SB 32 projects.

- SCE argues against the Clean Coalition's pricing proposal on the basis that it is an administratively-set price rather than a market-based price, *inter alia*. As argued in the Preamble, the Clean Coalition's proposal is another form of market-based price and SCE provides no precedent for defining what is and is not a "market price".
- SCE also seeks further details with respect to the Clean Coalition pricing proposal, including whether program capacity will be allocated on a first-come first-served basis, lottery or some other mechanism. This is a fair criticism and we address this question below with a proposal for a prioritized queue.

Daisy chaining

- The Clean Coalition agrees with TURN's and DRA's recommendation that protection should be included against "daisy chaining," that is, breaking a larger project into smaller projects to qualify for the SB 32 FIT. We also agree that a good means for preventing daisy chaining is to prevent projects on adjacent properties to a developer's first project from obtaining SB 32 projects. We provide alternative contract language to address this issue below.

TOD

- PG&E and SCE argue that TOD values for SB 32 projects should reflect differences between energy-only and deliverable projects. The IOU argument lacks merit and should be rejected.

Program cap limit

- PG&E argues again that its procurement obligation under SB 32 should be suspended if its 33% RPS obligation is met. The Clean Coalition has previously supplied its objection to this suggestion and we reiterate it below.
- The Clean Coalition has previously argued that the Commission may under its inherent authority expand the size of the SB 32 program. The staff proposal agrees with our conclusion and we are pleased to read that SDG&E also agrees that the Commission has this authority.

Transitioning from AB 1969 to SB 32

- PG&E recommends that its AB 1969 waitlist not be automatically transferred to the new SB 32 program when this becomes available. Rather, PG&E argues that these waitlisted projects should receive no priority in the SB 32 program and should have to apply like any other applicant. This would be an unfair outcome and we recommend, to the contrary, that any waitlisted projects in a utility AB 1969 queue receive priority for SB 32 in the situation where the capacity available in the initial tranche is immediately oversubscribed.

Contracts

- PG&E argues: “There is no basis for using form contracts for 1-3 MW projects under the RAM Program that are different than form contracts for 1-3 MW projects in the FIT Program.” To the contrary, there is a very good reason for streamlining the PPA contract for SB 32 projects: the SB 32 program is designed for smaller projects than the RAM program and, as a feed-in tariff program, was explicitly created for expedited project development. By providing a much simpler contract, this objective may be achieved.
- PG&E states: “Since the Staff Proposal effectively differentiates between FIT projects under 1 MW and 1-3 MW FIT projects, it is reasonable to develop separate form contracts.” To the contrary again, even if there are differences in the final SB 32 adopted program between 1 MW and below projects and those

from 1-3 MW, a single standard contract template could be modified to accommodate any extra requirements for 1-3 MW projects. This would be far simpler and more consistent than having two separate contracts.

- PG&E proposes a number of specific contract additions. The Clean Coalition can accept proposed changes 1-7 and 11-15 but opposes proposed changes 8-10 (cost allocation, forecasting, etc., and energy-only TOD changes).
- SCE also objects to requiring PG&E's 1 MW and below PPA: "Fairness and practicality dictate that each IOU be able to use a contract it developed to meet its needs." The Clean Coalition feels that SCE's concerns are countervailed by fairness to developers and the intent of SB 32 in terms of keeping the program as simple as possible.
- Moreover, the additions that SCE calls for ("economic curtailment, seller's Resource Adequacy ("RA") obligations, and provisions regarding Standard Capacity Product") are not required by SB 32 and should not be added.

Net metering

- PG&E states that projects participating in net metering should be ineligible for SB 32. There is nothing in the net metering law or SB 32 that supports this assertion. To the contrary, staff has suggested that the "excess sales" option should be retained for SB 32 and, as such, it makes far more sense to allow an SB 32 project to participate in NEM and SB 32 for up to the first MW of the project (whether separately metered or not).

Deliverability

- PG&E's opening comments mirror SCE's previous arguments with respect to deliverability and section 399.20(i). PG&E and SCE argue that this section requires SB 32 projects to achieve full capacity deliverability and to sell resource adequacy to the utility. To the contrary, 399.20(i) only requires that <u>if</u> a project is able to sell resource adequacy it must sell it to the utility. There is an implied "if" in this section and it should be read accordingly.

"Strategically located" projects

- SCE argues that it should be able to reject projects that are not "strategically located" if they are not in the "preferred" zones of SCE's new interconnection map. The Commission should reject SCE's recommendation. Rather, as the Clean Coalition has argued in previous comments, the interconnection study process itself should be considered fulfillment of this component of SB 32.
- Alternatively, the Clean Coalition would support "Option 2" in the staff proposal, which would allow projects to be considered strategically located if they do not exceed 100% of the minimum load of the relevant substation.

I. Comments

a. Pricing

i. TURN

The Clean Coalition agrees with TURN (TURN Opening Comments, pp. 1-2) that the established Market Price Referent is a more appropriate base price for SB 32 than the RAM clearing price, but as we wrote in opening comments on the staff proposal we can also accept using the RAM clearing price as the base price

We strongly disagree, however, with TURN's suggestion that SB 32 projects should, if RAM pricing is used in SB 32, be a subset of the RAM's 1,000 MW. TURN's rationale fails because the Legislature has mandated that utilities procure 750 MW of 3 MW and below feed-in tariff projects, which means that costs for 3 MW and below projects are the appropriate avoided cost. Furthermore, in the determination of avoided cost for a marginal unit of procurement, there is no legal basis for requiring that a specific unit of procurement is actually avoided.

We also disagree with TURN's objections (p. 3) to including a transmission cost adder to normalize the RAM clearing price for SB 32. TURN seems to miss the point of staff's suggestion: that the actual price paid by ratepayers for transmission-interconnected RAM projects would not be captured in the SB 32 avoided cost calculation unless the transmission adder is included.

We also disagree with TURN's statement (p. 7): "If locational adders are going to be applied, the Commission must guarantee that the savings associated with deferred capital investments will flow through to ratepayers." Neither federal law nor FERC precedent requires any guarantee by the Commission of ratepayer savings. The staff proposal correctly captures applicant precedent with respect to avoided costs and FERC has made it clear that it will be highly deferential to states in setting avoided costs under PURPA. The Commission has gone above and beyond its obligations by commissioning the detailed report on avoided costs from E3 – setting an example to the nation of how to capture the full benefits of distributed generation to ratepayers.

As we stated in our opening comments, SB 32 requires that ratepayers be indifferent to SB 32 projects and this means not only indifferent in terms of not paying any more for SB 32 projects, but also in not receiving uncompensated benefits from SB 32 projects. The staff proposal strikes the correct balance between ensuring that ratepayers are not overpaying or underpaying for SB 32 projects.

TURN also states (p. 8): "An automatic price adjustment due to program subscription levels – whether based on a percentage change or an absolute $/MWh change – cannot correlate with actual market price changes." This statement erroneously implies that there is an "actual market price" to which the SB 32 program must seek to "correlate". As explained in the Preamble of these comments, the pricing methodology implemented in SB 32 is setting the market price for this market segment and the automatic price adjustment is a key component of the price discovery.

TURN also recommends (p. 11) that only one RAM clearing price be set for each utility (for the category with the most contracts). This recommendation is antithetical to SB 32 and FERC precedent in that it would ignore the key differences between the three categories explicitly enumerated by SB 32: 1) peaking as available; 2) non-peaking as available; 3) baseload. Prices may be quite different for each of these categories and if the utilities were to procure only peaking as available projects in RAM, as may be the case, then ratepayers would in fact be paying more than justified under TURN's recommendation.

ii. DRA

DRA states that it continues to support its Net Surplus Compensation pricing proposal from its August 26, 2011, comments (DRA Opening Comments, p. 1). The Clean Coalition previously addressed why this proposal is entirely inappropriate for SB 32 pricing, under the Commission's own recent guidance with respect to the existing AB 1969 feed-in tariff. In other words, DRA is seeking to re-litigate issues that have very recently been resolved by the Commission.

The Commission clearly distinguishes in D.11-06-016 long-term contracted power under programs like SB 32 (and AB 1969) and net surplus power under AB 920 (pp. 32-33, emphasis added):

> [W]e find the AB 1969 program is distinguishable from NSC because AB 1969 involves contracted power, while NSC involves payment for incidental, non-contracted power production.
>
> Second, we reject the proposal to use the MPR to set the NSC rate because we agree with the utilities and TURN that it is not appropriate to pay net exports which can be occasional, intermittent, and unpredictable, using a cost methodology that assumes a long-term projection of costs and includes a value for capacity. As SDG&E notes, NEM customers are not under a long-term contract to provide surplus generation.

DRA recommends in its opening comments that one of two primary objectives of the Commission in implementing SB 32 should be to ensure ratepayer indifference (p. 2). We agree. But as we have discussed above and previously in this proceeding, ratepayer indifference means both that ratepayers do not overpay for power under SB 32 but that ratepayers do not obtain uncompensated benefits from SB 32 projects. Accordingly, DRA contradicts itself by urging an inappropriate pricing mechanism while promoting ratepayer indifference because using DLAP pricing for SB 32 projects would obviously undercompensate SB 32 projects, as the Commission made clear in D.06-06-016.

DRA also states (p. 6):

> [A]s evidenced by the Energy and Environmental Economics, Inc. (E3) presentation on September 26, 2011, the use of a location adder has the potential to create excessive pricing under certain circumstances. Specifically, the E3 presentation demonstrated that in certain areas the hot spot locational adder payment for peaking as available can be as high as 0.0775¢/kWh which equates to $77/MWh. This locational adder is an additional payment on top of the base contract price derived from the RAM auction and seems excessive for the amount of transmission and distribution deferrals an individual project will likely contribute.

DRA does not rebut E3's analysis on its merits in any way. Rather, DRA seems to be stating only that it feels intuitively that the proposed pricing is too high. This is not sufficient for sound policymaking. Rather, if DRA disagrees with E3's calculation of the locational adder, and thus the calculated ratepayer benefit from SB 32 projects, it should address the merits.

iii. PG&E

PG&E states (p. 3): "Paying a non-peaking as-available resource a locational adder would be contrary to the clear language of Section 399.20(e) which requires that the resource 'offset the peak demand on the distribution circuit.'" PG&E is misinterpreting this language and non-peaking facilities should, under the terms of SB 32, also receive a locational adder. Section 399.20(e) means only that SB 32 projects should offset peak lead, which includes non-peaking resources because non-peaking resources, such as wind power, can offset peak load at various times and some coastal locations in California have a similar production profile as solar power.

For PG&E's interpretation of section 399.20(e) to be valid, this section would need to include the word "maximize" or something synonymous: "The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to [maximize the] offset [of] peak demand on the distribution circuit." But this is not in the law as written and SB 32 projects do not need to maximize peak offsets. Instead, SB 32 projects need only contribute in some manner to offsetting peak demand. Importantly, E3's proposal already takes into account the differences in offsetting peak demand by recommending a different locational adder calculation for peaking versus non-peaking resources.

PG&E argues that a single statewide RAM clearing price should be used as the SB 32 base price (p. 5). The Commission should reject this recommendation because renewable resource profiles vary markedly between IOU service territories, such that providing a single RAM base price for SB 32 would probably not present a base price appropriate for each service territory.

PG&E also argues (pp. 6-7) that "the Commission should expressly provide the IOUs a procedural mechanism to challenge the FIT pricing before being required to execute FIT contracts, similar to the advice letter process adopted for the RAM Program." This concern is unfounded, however, because RAM contracts are already limited with respect to reasonableness by the very advice letter process PG&E mentions. As such, any RAM clearing price used for SB 32 pricing will have already been deemed to be reasonable by the relevant IOU and the Commission, and the adjustments and adders to the base price will already be deemed reasonable in the approval of the decision implementing SB 32. No additional protection is required for SB 32 pricing, particularly if the Commission adopts a volumetric price adjustment mechanism like the Clean Coalition has recommended.

PG&E discusses a number of objections to E3's proposed avoided transmission cost and locational adder (pp. 7-8). PG&E misunderstands that the reason an avoided transmission cost is included is because the RAM clearing price won't otherwise include the ratepayer transmission cost (if the RAM contract at issue is interconnected to transmission instead of distribution). The RAM clearing price only includes the cost of generation, requiring that an avoided transmission component be included also.

PG&E also objects to what it claims is a duplicative inclusion of a transmission component in the locational adder. However, as Attachment D of the ALJ Ruling makes clear, E3 included a sub-transmission component in the locational adder, not a transmission component. Accordingly, PG&E's recommendation that the avoided transmission component be eliminated lacks merit.

As we argued in our opening comments, E3's calculations still fail to capture the full value to ratepayers because they don't include the avoided cost of new transmission upgrades and maintenance that won't be captured in either the avoided transmission component from the RAM contract or the sub-transmission component of the locational adder.

PG&E raises a concern about a potential perverse outcome from the proposed E3 locational adder, arguing that by providing the adder in hot spots only, more projects will be incentivized to locate in those hot spots. And with no limits on how many SB 32 projects may be located in each hot spot, more projects than are necessary for that hot spot may be located there, resulting in higher interconnection costs along with the locational adder being paid to those developers for up to 20 years (p. 20). The Clean Coalition agrees that this may happen under the staff proposal, but it very likely would not happen under our modified proposal to provide a graduated locational adder to all SB 32 projects, depending on location. As we discussed in our opening comments, the locational adder should be maximized in the hot spots designated in the staff proposal, but two other graduate locational adder payments should be made available for two other tiers, based on the calculated and averaged avoided costs on those circuits.

We suggest in these reply comments an additional means for avoiding the issue PG&E raises: each utility should provide a cumulative MW limit for each hot spot, beyond which that hot spot ceases to be a hot spot. This addition will ensure both predictability for developers and avoid overpaying for locational benefits. Together, our proposals would not only avoid a far-too-binary locational adder payment, but would also avoid the problem PG&E raises.

iv. SCE

SCE's method for determining the starting price in their MP FiT proposal should be rejected for exactly the same reason that DRA's proposal should be rejected: it is contrary to recent on-point Commission precedent from D.11-06-016. The Commission has in this decision very recently rejected DLAP-based pricing for long-term contracts.

As has been suggested by multiple parties, the MPR is a reasonable starting price, but we can also accept staff's proposal to use the RAM clearing price with appropriate normalization as the starting price.

SCE also states that QF pricing in the 1980s was "too high and led to the closing of the program due to oversubscription." (fn 16). The program did not end because prices were too high. Rather, the Commission has stated that it had an "embarrassment of riches" with respect to new QF renewables and it suspended the program because it received more offers than the grid could at that time handle. In fact, over 10 GW of renewables on California's grid today are still QFs from that era, demonstrating in the first successful feed-in tariff of its kind how feed-in tariffs could lead to rapid and cost-effective renewables.

SCE also objects to the staff proposed methodology, arguing that prices will be too high: "It would be inappropriate and inconsistent with the principle of preserving ratepayer indifference to adopt the Staff pricing proposal, particularly when such high pricing would divert resources away from more cost-effective sources of renewable energy." To the contrary, SB 32's ratepayer indifference provision requires, as we have noted previously, that ratepayers not only don't overpay but also that they don't underpay for value received. E3's proposal calculates the actual ratepayer value from SB 32 projects, as is required by SB 32. In ignoring locational benefits, the MPR has never captured full ratepayer value and thus is not a relevant comparison point for ratepayer indifference.

SCE argues, with respect to calculating avoided costs under recent FERC precedent, that "The Clarification Order makes clear that a state must consider all resources available to meet the particular portfolio standard." (P. 12.) SCE is mistaken, however, in that FERC does not limit its ruling to renewable portfolio standard laws. Rather, FERC stated (FERC Clarification Order, Para. 27, emphasis added) that "just as a state may take into account the cost of the next marginal unit of generation, so as well the state may take into account <u>obligations imposed by the state</u> that, for example, utilities purchase energy from particular sources of energy or for a long duration."

SB 32 is an "obligation imposed by the state" that requires utilities to procure at least 750 MW of 3 MW (about 550 MW for IOUs) and below renewable energy projects. Accordingly, the staff proposal to consider RAM contracts normalized for the 3 MW and below market is entirely in keeping with this recent FERC precedent. The Commission need not consider the broader RPS program, let alone non-renewable procurement, as SCE also argues.

SCE also raises concerns (p. 14) about the transmission cost component of the staff's avoided cost calculation, arguing that no evidence is presented to justify this as an avoided cost. SCE misses the point that the transmission component is included, as the staff proposal states, in order to normalize the RAM clearing price contract for distribution-interconnected SB 32 projects. As discussed, FERC precedent allows a state to consider the obligation imposed by the state to buy certain renewable energy products in setting the appropriate avoided cost.

SCE argues against the Clean Coalition's pricing proposal (p. A-3) on the basis that it is an administratively-set price rather than a market-based price, *inter alia*. As argued in the Preamble, the Clean Coalition's proposal is another form of market-based price and SCE provides no precedent for defining what is and is not a "market price".

SCE also seeks further details with respect to our pricing proposal, including whether program capacity will be allocated on a first-come first-served basis, lottery or some other mechanism (p. A-3). The Clean Coalition recognizes that first-come, first-served methods for allocating program capacity can suffer from unfairness in a heavily oversubscribed situation. It is contrary to the intent of the SB 32 program for viable projects with a high certainty of near-term deployment to be denied a contract due to missing the "cutoff" by a few minutes, or even a day.

Other FiT programs implemented in the United States that began with a first-come, first-served policy have experienced such issues and subsequently switched to a lottery system (Gainesville, FL and Oregon). The Clean Coalition believes that such a lottery system adds unnecessary risk to the program almost to the same degree that an auction system presents significant added risk to developers. Instead, the Clean Coalition proposes that the Commission design a prioritized ranking system for capacity allocation specifically in the case where the entire available capacity within a utility's tranche is subscribed within the first day that the tranche is made available.

For all projects that apply within the first day and satisfy the viability criteria, the

Commission assigns queue positions in the program according to objective criteria relevant to when a project will come online. Projects that are due to come online more quickly should be given higher priority. Suggested criteria include:

- Progress through the interconnection study process
- Whether the project was on an AB1969 waitlist with the utility

b. Daisy chaining

The Clean Coalition agrees with TURN's (TURN Opening Comments, p. 9) and DRA's (DRA Opening Comments, p. 3) recommendation that protection should be included against "daisy chaining," that is, breaking a larger project into smaller projects to qualify for the SB 32 FIT (p. 9).[1] TURN states:

> TURN recommends that the Commission add a clause in Section 4.3 of the proposed contract ("Seller Representation") that requires the seller to represent that the project represents the only project being developed by the seller any a single or contiguous piece of property.

We recommend, however, that the actual contract language be modified to read: "Seller represents that the project is not part of a larger project on the same property or an adjacent property that will seek any more than one SB 32 contract, unless the SB 32 contract capacity sought does not exceed three megawatts, in which case the developer may obtain more than one SB 32 contract, up to three megawatts total for all SB 32 contracts at that site. Sellers may seek more than one SB 32 contract and more than three megawatts of contract capacity for any projects that are not located on the same or an adjacent parcel, subject to seller concentration limits."

c. TOD

[1] PG&E shares this concern, but does not propose a solution (PG&E Opening Comments, p. 29).

PG&E (p. 10) and SCE argue that TOD values for SB 32 projects should reflect differences between energy-only and deliverable projects. This argument lacks merit because there has been no consideration in the RPS proceeding of differentiating TOD payments based on energy-only or deliverable projects. Moreover, the draft 2011 MPR resolution includes no difference in payments in this regard. Accordingly, the IOU argument lacks merit and should be rejected.

d. Program cap limit

PG&E argues again that its procurement obligation under SB 32 should be suspended if its 33% RPS obligation is met (p. 26). The Clean Coalition has previously supplied its response to this suggestion and we reiterate it here: SB 32 is a stand-alone law that, while related to SB 2 (1x) (the new RPS law), imposes independent procurement requirements on utilities. As such, even if a utility were to meet its RPS obligations in any given year, its obligation to procure its share of the SB 32 program would not be suspended.

The Clean Coalition has previously argued that the Commission may under its inherent authority expand the size of the SB 32 program. The staff proposal agrees with our conclusion and we are pleased to read that SDG&E also agrees that the Commission has this authority (SDG&E Opening Comments, p. 14).

e. Transitioning from AB 1969 to SB 32

PG&E recommends that its AB 1969 waitlist not be automatically transferred to the new SB 32 program when this becomes available (p. 26). Rather, PG&E argues that these waitlisted projects should receive no priority in the SB 32 program and should have to apply like any other applicant. This would be an unfair outcome and we recommend, to the contrary, that any waitlisted projects in a utility AB 1969 queue receive priority for SB 32, in the situation where the capacity available in the initial tranche is immediately oversubscribed. Each waitlisted developer should have a chance to indicate its interest within a reasonable time before the first SB 32 application window opens.

f. Contracts

PG&E makes a number of arguments against adopting PG&E's 1 MW and smaller PPA for all SB 32 projects. PG&E argues (pp. 28-29): "There is no basis for using form contracts for 1-3 MW projects under the RAM Program that are different than form contracts for 1-3 MW projects in the FIT Program." To the contrary, there is a very good reason for streamlining the PPA contract for SB 32 projects: the SB 32 program is designed for smaller projects than the RAM program and, as a feed-in tariff program, was explicitly created for expedited project development. By providing a much simpler contract, this objective may be achieved.

PG&E states (p. 29): "Since the Staff Proposal effectively differentiates between FIT projects under 1 MW and 1-3 MW FIT projects, it is reasonable to develop separate form contracts." To the contrary again, even if there are differences in the final SB 32 adopted program between 1 MW and below projects and those from 1-3 MW, a single contract could be modified to accommodate any extra requirements for 1-3 MW projects. This would be far simpler and more consistent than having two separate contracts.

PG&E proposes a number of specific contract additions, starting on p. 31. The Clean Coalition can accept proposed changes 1-7 and 11-15 but opposes proposed changes 8-10 (cost allocation, forecasting, etc., and energy-only TOD changes). Briefly, we don't agree that cost allocation language needs to be in this simplified contract. We also don't feel that forecasting requirements should apply to these smaller-size projects, and as discussed above, we don't agree that TOD payments should be adjusted for energy-only projects.

SCE also objects to requiring PG&E's 1 MW and below PPA (p. 17): "Fairness and practicality dictate that each IOU be able to use a contract it developed to meet its needs." The Clean Coalition feels that SCE's concerns are countervailed by fairness to developers and the intent of SB 32, in terms of keeping the program as simple as possible. By having just one contract for all IOUs, the program will be vastly simplified and developers will save significant time and funds in terms of not having to navigate the terms of multiple complex contracts.

Moreover, the additions that SCE calls for ("economic curtailment, seller's Resource Adequacy ("RA") obligations, and provisions regarding Standard Capacity Product", p. 18)) are not required by SB 32 and should not be added.

g. Net metering

PG&E also states that projects participating in net metering should be ineligible for SB 32 (p. 39). There is nothing in the net metering law or SB 32 that supports this assertion. To the contrary, staff has suggested that the "excess sales" option should be retained for SB 32 and, as such, it makes far more sense to allow an SB 32 project to participate in NEM and SB 32 for up to the first MW of the project (whether separately metered or not).

h. Deliverability

PG&E's opening comments mirror SCE's previous arguments with respect to deliverability and section 399.20(i). PG&E and SCE argue that this section requires SB 32 projects to achieve full capacity deliverability and to sell resource adequacy to the utility. This is not, however, what section 399.20(i) states. Rather, the section states only that an SB 32 project must count toward the utility's resource adequacy requirements. It does <u>not</u> state that a project must achieve full capacity deliverability and thus the ability to sell resource adequacy credits. It only requires that <u>if</u> a project is able to sell resource adequacy it must sell it to the utility. There is an implied "if" in this section and it should be read accordingly.

PG&E also states (p. 35): "What the Commission cannot do is require customers to pay an embedded RA value price and not count the FIT projects toward the IOU's RA requirements." To the contrary, there is no embedded RA value in staff's proposed price methodology, so the issue PG&E raises is not an issue.

SCE raises the same point yet again (p. 19, p. 21), arguing that section 399.20 requires that developers achieve full capacity deliverability and sell resource adequacy to the utility. As just discussed, this is not the case as section 399.20(i) only requires developers to sell resource adequacy to the utility if they decide to obtain such.

i. "Strategically located" projects

SCE argues that it should be able to reject projects that are not "strategically located" if they are not in the "preferred" zones of SCE's new interconnection map (p. A-6). Many parties have expressed concerns about exactly this issue in various interconnection reform discussions, including the Clean Coalition.[2] These parties have stated that some other language (instead of "preferred" and "not preferred") should be used in SCE's interconnection map so as to avoid a chilling effect for interconnection of projects that are not in SCE's "preferred" zones.

The Commission should reject SCE's recommendation on this issue. Rather, as the Clean Coalition has argued in previous comments, the interconnection study process itself should be considered fulfillment of this component of SB 32. In other words, no additional authority should be conferred on the utilities under this component of SB 32.

[2] We cannot name the parties because of the confidential nature of these settlement discussions.

Alternatively, the Clean Coalition would support "Option 2" in the staff proposal, which would allow projects to be considered strategically located if they do not exceed 100% of the minimum load of the relevant substation.

Respectfully submitted,

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November 14, 2011

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 14th day of November, 2011, at Santa Barbara, California.

Tam Hunt

Clean Coalition