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)

COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON SECOND ASSIGNED COMMISSIONER'S RULING ISSUING PROCUREMENT REFORM PROPOSALS

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I. INTRODUCTION

Pursuant to the *Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals and Establishing a Schedule for Comments on Proposals* ("ACR") issued in this proceeding on October 5, 2012, and Administrative Law Judge ("ALJ") Simon's email directive on November 5, 2012, extending the comment due date, the California Wind Energy Association ("CalWEA") respectfully submits these comments on the Renewables Portfolio Standard ("RPS") procurement reform proposals presented in the ACR.

CalWEA has reviewed the ACR and provides comments below on certain proposals described in the ACR and related questions posed in the ACR.

II. COMMENTS ON ACR PROPOSALS

A. Standards of Review for IOUs' Shortlists

The ACR proposes that the investor-owned utilities ("IOU") should submit their RPS solicitation shortlists via a Tier 3 Advice Letter ("AL"), and the shortlists would be reviewed for consistency with the IOU's procurement plan, determination by the independent evaluator ("IE") that the shortlist was fairly selected, assessment of the viability of the shortlisted projects relative to all bids, and consistency with the IOU's procurement expenditure limitation (once adopted by the Commission). The IOU would not be able to contract with bids on the shortlist until the Commission approves the shortlist.[1]

1. Provide comments on the strengths and weaknesses of increasing the level of review of IOUs' shortlists. If an alternative review process or review standards are proposed, include justification for the proposal.

Requiring a Tier 3 AL to seek approval of IOU shortlists will introduce unnecessary delay into the RPS procurement process. A Tier 3 AL process would take a minimum of three months (likely more given the volume of data to be reviewed). Decision 12-11-016 (approving the 2012 RPS Procurement Plans) adopted a requirement that RPS power purchase agreements ("PPA") must be executed within 12 months after shortlist submittal. Thus, at least 25% of the time available for parties to negotiate PPAs would be lost to the shortlist review process. Moreover, there is no guarantee that this up-front effort would add any expedition to subsequent review of executed PPAs. As described in the ACR's PPA standard of review proposals, the Commission will still need to compare an executed PPA to updated solicitation data points, notwithstanding the prior review of the shortlist. Given the extra time required for the review required by this proposal, CalWEA recommends retaining the existing Tier 2 Advice Letter process for review of the IOUs' shortlists.

B. Establish Date Certain for Request for Commission Approval of Contracts

The ACR proposes that RPS PPAs must be signed within one year after the Commission's approval of the shortlist, and the IOU must file the executed PPA for CPUC Approval within one month after execution of the contract.[2]

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[1] ACR at 9-10.

2. **Discuss the strengths and weaknesses of the proposal to set a time requirement for requesting Commission approval of an RPS contract. What impact will it have on the market, ratepayer, and regulator? If an alternative time requirement is proposed, include a justification for the proposal.**

CalWEA supports the requirement for IOUs to submit PPAs for Commission approval within 30 days after execution of the PPA. While this proposal is helpful, CalWEA submits that it is only half a solution. As the ACR notes, the analysis used to justify execution of a particular PPA can become stale if there is a long lag time between execution and Commission review. However, this lag can result from an IOU delay in submitting the PPA, which the ACR addresses, or as a result of Commission delay in reviewing the PPA after it is submitted, which the ACR does not address. The harm resulting from the delay is the same in either circumstance. Thus, CalWEA supports the proposal to require submission of the PPA within 30 days after its execution, but further encourages the Commission to commit to expedited review of the PPAs that are submitted for its review.

C. Expedited Review of RPS Purchase and Sales Contracts

The ACR proposes that RPS PPAs for the purchase or sale of RPS energy with a delivery term of less than five years can be filed for approval via Tier 1 AL if certain conditions are met. The ACR further proposes that RPS PPAs (excluding bilateral PPAs) with a delivery term of more than five years can be filed via Tier 2 AL if certain other conditions are met, including satisfaction of minimum viability screens.[3]

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[2] ACR at 10.
[3] ACR at 11-16.

3. The above proposal defines expedited review prerequisites differently for contracts <5 years and those ≥5 years in term length. Comment on the appropriateness of the 5 year term length distinction. If an alternative is proposed, include a justification for the proposal.

CalWEA has no comment on the 5-year term length distinction.

4. The above proposal allows for contracts that meet all of the prerequisites to be submitted with Tier 1 and Tier 2 Advice Letters for contracts <5 years in term length and contracts ≥5 years in term length, respectively. Comment on the appropriateness of the designated Advice Letter Tier. If an alternative is proposed, include a justification for the proposal.

None of the RPS contracts should be eligible for submission via Tier 1 AL, which is effective pending disposition. Even short-term RPS contracts require an analysis of pricing, consistency with prior Commission decisions, and other criteria. These requirements are much more complex than the typical subject matter of a Tier 1 AL, such as a 'non-substantive editorial change to the text of a tariff."[4] Given the complexity, approval of the IOU's contract should not be permitted without prior review. Thus, expedited review should occur only via a Tier 2 AL irrespective of the duration of the delivery term.

5. The above proposals do not apply to sales contracts five years or greater in term length. Is there a market need to extend an expedited approval process to sales contracts five years or greater in term length?

There should not be a market need for expedited review of sales contracts in excess of five years. The ACR proposes that the IOU's purchase contracts will be generally subject to review for their fit with the IOU's RPS net short.[5] As a result, the IOUs are not expected to significantly overprocure RPS energy on a long-term basis. Rather, RPS sales should be necessary only to optimize RPS portfolio value in the short-term, within a compliance period. If

[4] General Order 96-B, Energy Industry Rule 5.1.

[5] Given the numerous assumptions that are made to calculate the RPS net short, and the reality that the 33% requirements is a floor, not a cap, CalWEA encourages the Commission to take a long-term view of what constitutes consistency with an IOU's RPS net short. *See* response to number 8 below.

an IOU has sufficient excess RPS supply to contemplate a long-term RPS sale, this circumstance warrants the more rigorous Commission review afforded by a Tier 3 AL.

6. The above proposal requires contracts using the expedited review process to be selected from competitive solicitations but it also allows bilateral contracts <5 years in term length if they are of equivalent or better net market value than offers from a prior solicitation for similar products. Would a solicitation for short-term transactions be robust enough to adequately benchmark short-term bilateral transaction if the contract is negotiated bilaterally?

All relevant information should be considered when price-benchmarking short-term contracts. This includes the results of recent solicitations for similar products, as well as recent benchmarks provided by bids for long-term contracts that are capable of supplying the same need as the proposed short-term product (which may include long-term bids from existing projects available in the near-term).

7. The above proposal extends the expedited approval process to contracts greater than five years in term length. Because long-term contracts are primarily for generation from facilities that are not yet operating, viability screens are proposed as prerequisites to reduce RPS portfolio risk for the IOUs and ratepayers. Comment on the strengths and weaknesses of the proposed viability screens.

CalWEA offers no comment on the proposed viability screens.

D. Improve RPS Power Purchase Agreement Standards of Review – Contracts from Solicitations

The ACR proposes a standard of review ("SOR") for contracts resulting from an RPS solicitation with projects utilizing commercially proven technology and for which expedited treatment is not available or is not requested.[6]

[6] ACR at 19-20.

8. The above proposal requires contracts to be consistent with an IOU's net short approved in the most recent Procurement Plan. Propose how this criterion could be applied to an individual contract.

The Commission should take a long-term view of the IOU's net short in determining whether an individual PPA is consistent with the IOU's RPS net short for purposes of the proposed SORs. As an initial step, the Commission should take the expected annual energy deliveries under the PPA and apply the development failure assumption used by that IOU to develop its RPS net short to derive the risk-adjusted expected annual deliveries. Then, the Commission should add the risk-adjusted expected annual deliveries from such PPA to the IOU's RPS portfolio, beginning with the first full year in which the PPA requires energy deliveries from the project. To the extent that the IOU's RPS portfolio shows surplus generation in any of the earlier years due to addition of energy from the PPA under review, those excess deliveries should be assumed to be carried forward to the full extent possible under the Commission's banking rules. So long as there is sufficient need in the IOU's portfolio for the risk-adjusted expected annual deliveries under the PPA (after applying banking), then the PPA should automatically be deemed to be consistent with the IOU's RPS net short.

The Commission should also consider any PPA that results in total expected procurement within a reasonable margin above the calculated net short to be consistent with the IOU's RPS net short for purposes of the proposed SOR. Numerous assumptions go into the calculation of the RPS net short, and variation of one or more of those assumptions could change the purely mathematical assessment of RPS net short. Moreover, the 33% of retail sales used to calculate the RPS net short is a floor, not a cap.[7] Therefore, there should be no rigid cut-off point based on

[7] Cal. Pub. Res. Code § 25740 ("It is the intent of the Legislature in establishing this program, to increase the amount of electricity generated from eligible renewable energy resources per year, so that it equals *at least* 33 percent of total retail sales of electricity in California per year by December 31, 2020." (emphasis added)).

the calculated RPS net short. Rather, proposed projects with ratepayer benefits should satisfy the "consistent with the RPS net short" component of the proposed SOR if they are within a reasonable margin of the calculated RPS net short.

9. Are the proposed cohorts to be used to evaluate the reasonableness of a contract's price, net market value, and viability appropriate? If not, provide an alternative proposal and justification for the alternatives.

Yes, the proposed cohorts are appropriate. The reference to the shortlisted bids represent the other opportunities available to the IOU at the time a given project was selected for negotiation of a PPA, and the reference to all PPAs executed within the prior 12 months provides a mechanism to evaluate the PPA against the pricing and viability associated with other projects providing binding pricing commitments backed by at-risk credit support. However, because executed PPAs represent binding pricing commitments, the Commission should give greater consideration to these data points.

In addition, the proposal should be revised to clarify that the proposed cohorts are assessed on an IOU-specific basis, such that a given PPA is compared to pricing and viability associated with bids received, and contracts executed, by the same IOU that is a party to such PPA. IOU-specific cohorts should be used because each IOU uses its own *pro forma* PPA, and its own time-of-delivery ("TOD") factors, which can lead to differences in pricing between the IOUs. Also, the proposal should be clarified to reflect that the Commission can exercise discretion in evaluating the data comprising the benchmarks, including consideration of any pricing trends revealed by such data.

E. Improve RPS Power Purchase Agreement Standards of Review – Bilateral Contracts

The ACR proposes a separate SOR for contracts resulting from bilateral negotiations, which consists of the same components as the SOR for contracts resulting from a solicitation plus a requirement that the project meet specified minimum development milestones.[8]

10. Are there additional reasons for executing bilateral power purchase agreements outside of the solicitation process other than those stated above (e.g. fleeting opportunity, very high viability, near-term commercial operation date, etc.)? If yes, provide the additional reasons and the justifications for bilateral contacts outside of a solicitation.

While this may fall within the concepts of fleeting opportunity and near-term commercial operation date, CalWEA reminds the Commission that the current proposal for a federal production tax credit ("PTC") extension would extend the PTC only for projects that commence construction prior to the end of 2013.[9] Thus, the rules for bilateral contracting should be sufficiently flexible to allow the IOUs to execute PPAs outside the solicitation process when necessary to ensure that IOU ratepayers will reap the benefits of projects eligible for favorable federal policies, such as renewable energy tax credits. Equally important is ensuring a streamlined contract submission and review process, as described in response to number 2 above. While requiring submission of the PPA within 30 days after its execution is a good start, the Commission must also commit to expedited review of that PPA to ensure that PPA approval is timely enough for the project to obtain the benefit of favorable federal policies.

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[8] ACR at 21-24.

[9] A proposal to extend the PTC for projects that start construction in 2013 won bipartisan support from the Senate Finance Committee on August 2, 2012, as part of an overall "tax extenders" package. The bill awaits action by the full Congress, expected in its lame-duck session after the November elections. *See e.g.*, http://www.reuters.com/article/2012/10/19/us-utilities-windpower-usa-idUSBRE89I0TX20121019.

11. Are the proposed cohorts to be used to evaluate the reasonableness of a contract's price, net market value, and viability appropriate? If not, provide an alternative proposal and justification for the alternatives.

CalWEA supports the proposed cohorts. Bilateral contracts should be compared to the same benchmarks used to evaluate contracts that result from solicitations because bilateral contracts effectively substitute for additional capacity that could be obtained via solicitation opportunities.

12. Are the proposed criteria and standards within the minimum viability requirements appropriate for bilaterally offered projects? If not, provide alternative criteria and standards and justification for the proposal.

CalWEA recommends that the proposal be revised to remove the Phase II Interconnection Study requirement. Prior CAISO interconnection studies have been subject to significant delays. If bilateral contracts are supposed to be available for fleeting opportunities, then execution of the contract should not be delayed while the parties wait for the results of the CAISO interconnection study. Similarly, if the requirement for a Phase II Interconnection Study is removed, then the requirement for the filing of an application for a Permit to Construct or an AL for an approved Notice of Construction should also be removed.

F. Improve RPS Power Purchase Agreement Standards of Review – Amended Contracts

The ACR also proposes a SOR for amendments to existing contracts that substantially change the contract, or modify a term that is an explicit term of contract approval, and proposes a new requirement that change the project's technology (e.g., solar photovoltaic vs. solar thermal) must be re-bid into the next RPS solicitation.[10]

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[10] ACR at 25-28.

As the ACR notes, CalWEA has previously expressed its concerns with the existing process for Commission review of amendments to existing contracts.[11] CalWEA has asserted that the current process has resulted in a vibrant secondary market in which PPAs are bought and sold without a need to actually develop the underlying projects; developers can seek amendments to conform the PPA to the developer's preferred project, even if this entails the use of an entirely different technology. In turn, the ease with which a PPA can be amended under the current process has encouraged a speculative approach to solicitations; a winning bidder currently has the opportunity to sell its PPA to a third party if the original project proves unviable.

CalWEA commends Commissioner Ferron for issuing the ACR, in part, to consider revising the process for Commission review of contract amendments.

13. The proposed SOR are for contract amendments that substantially modify a contract. Are additional SOR needed for other types of contract amendments (i.e., contract amendments that do not substantially modify approved contracts) or does review of "contract administration" within the IOUs' Energy Resource and Recovery Account filings encompass all other contract amendment types? If additional SOR are needed, propose alternative or additional SOR and describe the type of contract amendment that they would apply to.

As an initial matter, the Commission should not apply the proposed SOR broadly to "any contract amendment that substantially modifies a contract" because this standard is too vague. Parties to a PPA should understand whether a proposed amendment will trigger a mandatory Tier 3 AL filing obligation and, if so, the SOR that the Commission will apply to that amendment. Thus, the mandatory Tier 3 AL filing obligation should be limited to the specific enumerated categories as well as any amendment that modifies an explicit term of Commission approval of the original PPA. Any other amendment of the PPA should remain subject to Commission review of the IOU's administration of the PPA through the IOU's ERRA filing, or, if the IOU so

[11] ACR at 25.

chooses, Commission review and approval via a Tier 3 AL filing using a SOR that compares the amended PPA to the original PPA, rather than to current needs and market opportunities, for purposes of evaluating consistency with the RPS net short, pricing, net market value, and viability. To the extent that stakeholders or the Commission believe that additional enumerated categories triggering the mandatory Tier 3 AL filing obligation need to be added in the future, such additions can be vetted through the annual RPS Procurement Plan review process.

In addition, several of the specific enumerated triggers for the mandatory Tier 3 AL filing requirement should be modified or clarified (and in each case, should apply only to the extent the change is beyond whatever was permitted under the terms of the original PPA):

- Change in price – CalWEA submits that the primary concern should be with significant price increases (i.e., price changes that would have affected the bidding outcome). For example, a decrease in price alone (even if highly unlikely to occur absent other changes) would only have made the project more competitive and should not trigger a comparison to current market conditions. However, a change in price combined with one of the other material changes described below results in broader changes to the original deal that are indicative of a speculative bid. Thus, a significant increase in price should trigger the mandatory Tier 3 AL filing obligation, whether alone or in combination with other enumerated triggers, but insignificant price changes or price decreases should not trigger the mandatory Tier 3 AL filing obligation, unless paired with one of the other enumerated triggers.
- Change in capacity – CalWEA submits that any increase in capacity should trigger the mandatory Tier 3 AL filing requirement because it is essentially new

procurement; however, a decrease in capacity should not trigger the mandatory Tier 3 AL filing, unless paired with one of the other enumerated triggers. Project downsizing is frequently necessary to respond to concerns raised during the permitting process.

- Change in COD – CalWEA submits that the proposed trigger of three months is too narrow, particularly if unreasonable delays can be attributed to the permitting process. Instead, a change in COD of up to 12 months should be permitted without triggering the mandatory Tier 3 AL filing requirement, unless paired with one of the other enumerated triggers. The use of a 12-month period is more appropriate because many delays in the permitting process require an additional 12 months to resolve. For example, identification of a new species on a site can trigger the need for additional studies, which typically consider annual cycles.
- Change in project location – CalWEA submits that a change in the location of the project should not trigger the mandatory Tier 3 AL filing requirement unless the project's interconnection point also changes. For purposes of this category, a "change in project location" should be limited to scenarios in which the project relocates to an entirely new site, and exclude scenarios in which the boundaries of the existing site are revised.
- Changes in interconnection point – Similarly, CalWEA submits that a change in the project's interconnection point should not trigger the mandatory Tier 3 AL filing requirement unless there has also been a change in the project's location. The goal of the enumerated triggers should be to ensure heightened review of substantial modification of existing PPAs that is indicative of a speculative bid. A

change in a project's location or interconnection point alone does not necessarily constitute a wholesale change in the project, signaling that the project bid was speculative. Rather, these two categories should be looked at in combination to determine whether there has been a wholesale change in project location.

Finally, the ACR proposes that a change in technology requires re-bidding. CalWEA supports this element of the proposal, provided that it is clarified to exclude technology modifications within a technology class (such as PV panel manufacturer or turbine type) from the designation of a change in technology. Also, solely the addition of storage that improves value, without any of the other enumerated changes to the PPA, should not trigger a mandatory Tier 3 AL requirement.

The goal of each of the triggers for the mandatory Tier 3 AL filing requirement should be to ensure that developers are not rewarded for obtaining PPAs via speculative bidding, while preserving sufficient flexibility for the parties to the PPA to be able to adjust the contractual requirements to reflect the evolution of the project as it navigates the development process. An overly permissive approach to evaluation of PPA amendments allows the PPA itself to become a commodity that can be bought or sold without concern for having to actually develop the underlying project. Even if an amended PPA offers potential ratepayer benefits compared to the original PPA, the Commission should send the message that contracts are not place-holders. Otherwise, developers that offered viable projects that could have been selected in the original solicitation turn their attention elsewhere, or are left without a market for their viable projects.

In contrast, a process that requires developers to develop the projects they bid, while allowing for PPA amendments necessary to reflect changes in the project required to overcome the challenges of project development, encourages a functioning market. If developers know that there will be limited opportunity for wholesale changes in the PPA, the incentive to engage in speculative bidding will be substantially reduced. In addition, developers will likely submit bids for higher-quality projects for which the developer has a higher degree of confidence in its ability to deliver. By deterring speculative bidding and improving the quality of projects offered by bidders, the Commission can restore confidence in California's renewable energy market. This restored confidence will, in turn, benefit ratepayers by promoting competition within the RPS market.

14. Are the proposed cohorts to be used to evaluate the reasonableness of a contract's price, net market value, and viability appropriate? If not, provide an alternative proposal and justification for the alternatives.

Generally, CalWEA agrees with the proposed cohorts to be used to evaluate the reasonableness of the PPA amendment. To the extent that a PPA is being substantially amended in a way that materially alters the original least-cost, best-fit ("LCBF") evaluation of the project, the amended PPA should be compared to current market conditions to evaluate whether the IOU would be better off pursuing a new PPA with a new project. The requirement to meet current conditions as a condition to significant restructuring of the PPA encourages developers to bid legitimate projects and then develop the projects that were bid.

However, there are circumstances in which a developer may be reasonably likely to perform under the original PPA, but there are changes to the PPA that would be mutually beneficial to the developer and the IOU. In such circumstances, the Commission should not apply the comparison to current market conditions, which would discourage the parties to the PPA from amending the PPA in a manner that leaves both parties better off compared to the original PPA. Instead, the Commission should compare the amended PPA to the original PPA to determine whether the IOU and its ratepayers will obtain better value under the amended PPA than the original PPA. To ensure that the developer is reasonably likely to be capable of performing under its original PPA (thus demonstrating ratepayer benefits are actually being captured), this revised SOR for a mandatory Tier 3 Advice Letter filing should only be applied where the following minimum development milestones have been met, demonstrating that the project is well beyond the point of speculation: (i) full site control, (ii) Conditional Use Permit, BLM Record of Decision, CEC AFC, or equivalent has been obtained, (iii) interconnection agreement has been executed, and (iv) transmission system upgrades required for the project require a Permit to Construct or an approved Notice of Construction and the application or AL, as applicable, has been filed, or requires a CPCN and the CPCN has been granted.

15. Should minimum project development milestones (as proposed for the SOR for bilateral contracts) be incorporated into the SOR for amended contracts as a way to ensure only viable projects proceed with contracts, thus decreasing the amount of risk in the IOUs' RPS portfolios? If not, provide alternative SOR that would reduce the risk of IOUs' RPS portfolios.

See response to Number 14. Minimum project development milestones should not be applied to a mandatory Tier 3 AL filing generally, but should be applied to a mandatory Tier 3 AL filing in which the IOU seeks to apply a comparison to the original PPA LCBF evaluation in lieu of a comparison to current market conditions.

G. Improve RPS Power Purchase Agreement Standards of Review – Contracts Beyond the Scope of the Advice Letter Process

The ACR also proposes that contracts that do not satisfy the requirements for the SORs specified above must be submitted for review via application, and proposes a SOR for review of such contracts.[12]

[12] ACR at 29-32.

16. The above proposal proposes that the process by which IOUs must seek Commission approval of RPS contracts be based, in part, on the contracted amount of expected annual generation. Comment on how projects with multiple contracts for total facility capacity and projects with contracts for multiple phases should be treated under the proposal or propose an alternative delineation and justification.

If an IOU executes multiple contracts for the capacity of a single project or multiple contracts for multiple phases of a single project, then the Commission should considered the total capacity of all of the executed contracts as a single contract for purposes of applying the Commission's review requirements. If the IOU executes a single contract for only a portion of the capacity of a phased project, then the Commission should consider only the capacity of the executed contract, and not the capacity associated with additional phases of the project for which the IOU has not executed a contract, for purposes of applying the Commission review requirements.

17. Comment on the appropriateness of the requirement that contracts that are expected to provide annually more than one percent of the IOU's total bundled sales in the first full year of deliveries should be filed by application. Provide justification for any alternative proposals.

CalWEA has no comment on the proposed one percent threshold for triggering the requirement to file an application for PPA approval.

18. Are there additional circumstances for which RPS contracts should be submitted by application for Commission approval? For example, if the contract exceeds a certain capacity or it would cause a rate impact above a certain amount the IOU would be required to seek approval with an application. In the proposal, provide a justification and include not only the circumstance(s) but also any limits (e.g., all contracts that cause more than a 0.05 cents/kWh rate increase must be filed by application because that would cause a statistically significant rate increase to the average electric rate in California).

CalWEA has no comment on any additional circumstances that warrant PPA approval via application.

19. Are there any items (e.g., contract's net market value or viability score) in addition to the contract terms and conditions that should be part of the public record? Provide a justification.

CalWEA has no comment on whether there are any other items that should be part of the public record.

H. Standards of Review for Unbundled Renewable Energy Credits

The ACR proposes a SOR for contracts for the purchase of unbundled renewable energy credits.[13]

[19a]. Are there any other cohorts that unbundled REC contracts should be compared to? If yes, propose additional appropriate cohorts and the justification for their appropriateness.

CalWEA has no comment on the proper cohorts for evaluation of unbundled REC contracts.

[13] ACR at 33-35.

20. Are there any criteria in addition to need authorization, consistency with an IOU's renewable net short, consistency with Commission decisions, and price that should be considered by the Energy Division and the Commission when reviewing unbundled REC contracts for reasonableness?

CalWEA has not comment on the need for additional criteria for evaluation of unbundled REC contracts.

21. Is there a methodology that would accurately allow the comparison of unbundled REC contracts to bundled procurement? Please provide a quantitative example.

CalWEA has no comment on the methodology for comparing unbundled REC contracts to bundled procurement.

I. RPS Independent Evaluator Reports

The ACR proposes that the IE should include supplemental calculations of capacity value and ancillary services value for purposes of the LCBF analysis of bids and a definitive recommendation whether the IOU conducted its evaluation of bids in a fair and reasonable manner and whether the shortlist should be approved or rejected.[14]

22. Comment on the strengths and weaknesses of the IE providing supplemental calculations.

CalWEA supports the proposal to have the IE provide supplemental calculations of capacity and ancillary services value. The IOUs have not sufficiently explained their methodologies for performing these calculations, and it is currently unclear whether these calculations are being performed in a fair and consistent manner that appropriately values the products offered by individual projects rather than introducing qualitative biases.

[14] ACR at 35-36.

23. Are there additional evaluation criteria or requirements for IEs assigned to RPS solicitations that the Commission should adopt?

CalWEA recommends that the IE also provide supplemental transmission cost adder calculations because both the transmission cost adder and the capacity value calculation are necessary to determine whether RA procurement is being performed in an efficient manner.

J. Implementation of New Least-Cost, Best-Fit Requirements

The ACR seeks comment on how the Commission should implement the new LCBF requirements codified in California Public Utilities Code Section 399.14(a)(4).[15]

As an initial matter, CalWEA notes that improving the accuracy of each cost and value component of a renewable energy bid, as well as payment structure (TOD rates), is of critical importance to the RPS program. Objective, accurate quantification of these factors (and limiting subjective valuations) will serve several goals: (a) reduce the total net cost of achieving RPS goals by ensuring that contract costs are justified by their total value, such that overall system needs are met at least cost and best fit; and (b) ensuring transparency and reducing subjectivity in the bidding process, which in turn enables bidders to tailor their bids to maximize value, while increasing bidders' confidence in the fairness of the competition. A given renewable energy project need not supply all grid-service needs; just as its RPS-qualified energy should be competitive with other sources of the same, the other values of a potential incremental service (e.g., capacity or ancillary services) should be offset by equivalent or greater incremental value of those services.

[15] ACR at 37-38.

24. Please describe how the Commission should implement each of the four specific topics listed in Section 399.13(a)(4)(A). Please include quantitative examples where relevant.

In Decision 12-11-016 (accepting the 2012 RPS Procurement Plans), the Commission adopted the following standardized Adjusted Net Market Value ("ANMV") calculation to be used for the quantitative portion of the LCBF evaluation:

A = (E+C+S) – (P+T+G+I), where

E	=	Energy value
C	=	Capacity value
S	=	Ancillary Services value
P	=	Post-TOD PPA price
T	=	Transmission cost adder
G	=	Congestion cost adder
I	=	Integration cost adder

This formula is broad enough to capture the first two topics listed in Section 399.14(a)(4) – indirect transmission and integration costs, and procurement cost impact – subject to the revisions to the current methodology that are proposed below. The remaining two topics – project viability and workforce recruitment, training and retention efforts – are not capable of rigorous quantitative evaluation in the same manner as the first two topics. CalWEA proposes handling the remaining two topics in the same manner that they are currently used, which is to apply these qualitative factors as a basis for justifying the shortlisting of projects that are largely competitive, but might not have made it onto the shortlist on quantitative metrics alone.[16]

25. For each of these four topics, please compare your implementation proposal with the existing LCBF methodology as set out in D.04-07-029 and applied in the 2011 RPS Procurement Plans approved in D.11-04-030.

As noted in the response to Number 24 above, the current ANMV formula is broad enough to capture the first two categories in the statute, but the current approach to calculating

[16] *See e.g.,* D. 04-07-029 at 32.

the inputs to the ANMV formula do not appear to be accurately capturing the cost and value of individual bids.

Capacity Value

With respect to capacity value, the IOUs continue to provide vague descriptions of their methodology. The calculation of the market value of capacity should be much more straight-forward. The IOUs should be applying a specific metric to each type of renewable technology to derive the expected Resource Adequacy ("RA") capacity available from the project, and then multiplying that RA capacity by a RA capacity market price to determine the capacity value, which can then be discounted to present value. Each IOU should include in its RPS solicitation materials the IOU's assumptions for RA capacity by resource type, its forward price curve for RA capacity pricing, and its discount rate. Then, all stakeholders will have the information necessary to calculate the value to a given IOU of RA capacity that could be provided by a given project.

With a specific quantitative value for the capacity available from its project, a developer can make much more efficient decisions about whether to incur the costs associated with providing RA capacity, which also leads to more efficient expansion of the transmission system. As CalWEA has previously explained in this proceeding, projects are required to request during the interconnection process either Full Capacity Deliverability Status ("FCDS"), Partial Capacity Deliverability Status ("PCDS"), or Energy-Only ("EO"). The first two options (FCDS and PCDS) include the associated capability to provide RA capacity by funding Delivery Network Upgrade ("DNU") costs, while the third option (EO) precludes the ability to provide RA capacity but also avoids the construction of DNUs. The choice between FCDS, PCDS, and EO represents a separate decision point where the developer must choose whether to offer an incremental product to the IOU (i.e., a project can be offered as EO without RA capacity and avoid DNU costs, or offered as PCDS/FCDS with RA capacity and incur DNU costs). In some cases, the cost for these upgrades is significantly higher than the value of RA capacity that the upgrades create. To make an efficient choice, the developer must know the value of the RA capacity to the IOUs in addition to the cost of the DNUs. This knowledge not only improves the RA procurement process but also prevents developers from making inefficient interconnection choices that would lead to costly transmission upgrades to the detriment of the ratepayers.

Requiring all resources to obtain FCDS (or even PCDS) does not provide the most efficient approach to meeting RA procurement obligations either. In some cases, the cost for these upgrades is significantly higher than the cost to obtain an equivalent quantity of RA capacity in the RA market. In its original 2012 RPS Procurement Plan, SCE proposed to allow bidders to have the ability to designate the specific amount of RA capacity that the seller will provide for each month during the contract term, and allow the seller to provide this RA capacity from sources other than the project.[17]

In Decision 12-11-016, the Commission accepted the proposal to allow the specification of specific amounts of RA capacity, but declined to adopt the third-party supply proposal because the Commission believed the record to be incomplete.[18] However, the Commission expressly invited parties to raise the issue in response to the LCBF provisions of the ACR.[19] Accordingly, CalWEA reiterates its request for the Commission to allow bidders to package third-party RA capacity with EO renewable energy projects.

[17] SCE 2012 Written Plan at 28.
[18] D. 12-11-016 at 59-60.
[19] *Id.*

TOD Factors – Energy Value and Post-TOD PPA Pricing

In Decision 12-11-016, the Commission indicated that it is "receptive to examining the methodologies used to derive the TOD Factors in a subsequent part of this proceeding" including in response to the LCBF portion of the ACR.[20] The current TOD factors reflect current market conditions, while the utilities are now procuring for the third compliance period, by which time the supply mix will have markedly changed due to the utilities' compliance with the 20% RPS and the first and second compliance periods of the 33% RPS. A recent report from the Lawrence Berkeley National Laboratory indicates that the net economic value of each renewable technology changes significantly as its market penetration increases, some declining very markedly as penetration approaches 10%.[21] Furthermore, the load pattern in California is gradually shifting towards a dominant evening peak load condition during a large portion of the year.

While the results of the LBNL study may not be directly applicable to TOD factors, the aforementioned factors, among others, will likely affect the market value of renewable generation. As a result, the current TOD factors will likely become increasingly inaccurate for purposes of valuing incremental generation as the supply mix changes over time. Given the large volume of renewable energy for which the IOUs have already contracted, the Commission should initiate a re-evaluation of the current TOD factors to more appropriately value the benefit of incremental renewable energy at various times of day. In particular, the Commission should evaluate whether high on-peak payment rates are warranted, given increasing supply during those time periods, and whether the existing TOD periods should be revised, or new TOD periods created, to reflect the shift towards increasing demand during evening peak periods.

[20] D. 12-11-016 at 38.
[21] Mills, Andrew, Lawrence Berkeley National Laboratory, "Economic Valuation of Solar PV and Flexible Resources at Increasing Penetration Levels", Intersolar North America Conference (July 11, 2011) at 16.

Moreover, as the utilities all operate within the same CAISO system, the Commission should investigate whether a legitimate basis exists for the separate TOD structures across the three IOUs, which vary widely from one IOU to the next.

In addition, the Commission's decisions on TOD factors have routinely stated that TOD factors should "recognize the extent of the need for additional capacity."[22] In accordance with this approach, the Commission also approved IOU proposals to apply separate TOD factors to EO projects versus FCDS projects.[23] However, the Commission-adopted ANMV calculation already includes a separate variable for valuing the capacity provided by a given project. To avoid double-counting capacity benefits offered by a given project, the Commission should consider limiting TOD factors to a single set of energy-only TOD factors. Indeed, San Diego Gas & Electric Company previously proposed to delete its RA adder in order to avoid this double-counting concern when it proposed all-in TOD factors.[24]

Finally, the Commission should require the IOUs to clarify that the same TOD factors that are used for determining the Post-TOD PPA Pricing variable in the ANMV calculation are also used to derive the Energy Value variable in the ANMV calculation.

<u>Transmission Cost Adders</u>

With respect to transmission cost adders, the IOUs again need to be more explicit with their methodology. This calculation should be very straight-forward – the IOU should publish its expected cost over 10, 15, 20, and 25 years (corresponding to the available PPA delivery terms) for every million dollars in reimbursable network upgrade costs; then, a given developer can multiply the applicable rate for the applicable delivery term times its expected reimbursable network upgrade costs and divide that total cost over the expected generation from the project to

[22] D. 12-11-016 at 38 (quoting D. 06-05-039 at 69).
[23] *Id.* at 37-38.
[24] D. 11-04-030 at 47.

derive its transmission cost adder, in dollars per MWh. With this information and the information regarding capacity value, the developer can make an efficient decision regarding its interconnection status.

In addition, the Commission should clarify that the transmission cost adders need to reflect changes in the CAISO interconnection process. For new interconnection requests, the project will not be assigned incremental network upgrade costs if it is located in an area with latent capacity, and thus there should be no transmission cost adders for such projects. For other projects that are assigned network upgrade costs, the transmission cost adders should recognize that the reimbursable network upgrade costs will be capped at $60,000/MW.

<u>Integration Cost Adder</u>

With respect to integration cost adders, the Commission has not previously allowed the IOUs to apply one, even though it is included in the ANMV formula.[25] As many parties have noted, the time has come to develop integration cost adders that can be applied by the IOUs. However, based on work already completed by the CAISO, the amount of these integration cost adders are substantially less than suggested by other parties; as with TOD factors, these figures should be estimated for the 2016-2020 time period, which is the period for which procurement is being sought.

In SB 2 (1X), the Legislature expanded the Commission's obligations with respect to the LCBF bid evaluation methodology. At the same time, Section 399.13(a)(4) retained the existing requirement that the LCBF process must consider "estimates of indirect costs associated with … ongoing electrical corporation expenses resulting from integrating and operating eligible renewable energy resources." The ACR asks parties to present detailed proposals on implementing this section of § 399.13(a)(4), including quantitative examples and explanations of

[25] *See e.g.*, D. 12-11-016 at 27-29.

how the proposal would affect ratepayer costs and improve the efficiency of RPS procurement. At the outset, CalWEA emphasizes that the purpose of such an adder should be for use in evaluating bids from new RPS resources, and such an adder should not impact RPS contracts which have been approved, signed, or are under negotiation from past RPS solicitations.

The Commission has long had a placeholder in the LCBF methodology for the costs of integrating renewable resources. The Commission first addressed the possible inclusion of integration costs as part of the LCBF process in D. 04-07-029, the order which established the LCBF approach in advance of the first RPS solicitation in 2004. That decision recognized that the integration of increased amounts of renewable resources could require the procurement of additional ancillary services such as regulation and load following. Based on a CEC-commissioned study, the Commission found that, at the renewables penetration levels existing at that time plus "reasonable" expected increases in those levels, the need for additional ancillary services to integrate renewables was "negligible." As a result, the Commission declined to adopt a non-zero integration cost adder, but noted that it would change this determination in the future if warranted by further studies of integration costs.[26] Since that order, the Commission has been presented periodically with proposals to implement non-zero integration cost adders. Generally, the utilities have sought authority to adopt an adder using their own judgment or to use an average of adders from integration cost studies performed for other utilities or control areas. The Commission consistently has declined to adopt such an adder, stating clearly such an adder needs to be developed with public review and comment and based on data from the CAISO control area.[27] The Commission's most recent rejection of such an integration cost adder

[26] D. 04-07-029, at 12-14.

[27] D.07-02-011, which accepts RPS Procurement Plans for the 2007 RPS solicitations, at 56; D.08-02-008, Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations (February 2, 2008) at 44; and D.11-

occurred very recently, in the order on the utilities' 2012 RPS plans (D. 12-11-016) issued on November 14, 2012, which rejected non-zero adders proposed by SCE and PG&E.[28]

In deciding not to adopt the adders proposed by SCE and PG&E, D. 12-11-016 notes that the Commission, the CAISO, and other parties are undertaking studies of integration costs for renewables in the 2012 long-term procurement plan ("LTPP") case, R. 12-03-014, and that this phase of the RPS proceeding would solicit proposals for integration cost adders to be used in the LCBF process. The decision encouraged parties to participate in R. 12-03-014 and related CAISO processes, and in this proceeding, "to provide data and cost information to develop a robust and meaningful integration cost adder." CalWEA has been an active participant on renewables integration issues in all of these forums, and presents below its proposal for an integration cost adder for use in the LCBF process.

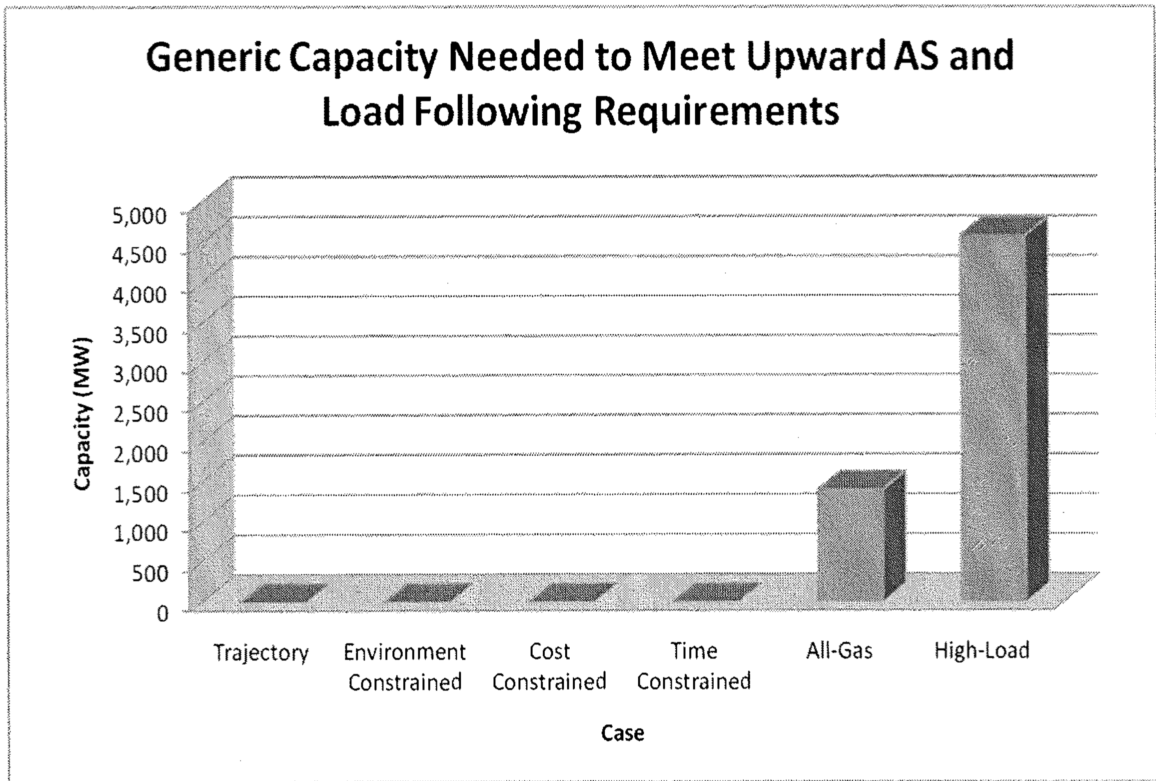
An integration cost adder should have both long- and short-term cost components. The long-term cost component should be the long-term, capacity-related costs of new flexible resources that must be procured, or the capacity-related costs of existing flexible resources which must be kept in operation, solely to integrate renewables. The new resources could be new combustion turbines or other types of flexible generation, although "non-generation" alternatives such as storage or demand response also could be considered. The short-run cost component should be the ongoing operating costs of the balancing resources which are needed to integrate renewables. CalWEA discusses each of these components below.

Recent LTPP cases have investigated the need for new resources to integrate renewables. The settlement in the 2010 LTPP case (R. 10-05-006), which the Commission adopted in D. 12-04-046, recognized that parties have yet to identify any long-term procurement needs that result

04-030, Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements at 23.

[28] D. 12-11-016, at 27-29.

from integrating up to 33% renewables. In the 2010 LTPP case, none of the 33% RPS scenarios which used the Commission's preferred assumptions showed any long-term procurement needs for renewables integration. The only modeling scenarios in which there was a need for additional resources to provide flexible generation were two scenarios which the CAISO constructed, an "All Gas" 20% RPS scenario and a High Load scenario. These results are summarized in the figure below from the CAISO's 2010 LTPP testimony of Mark Rothleder in R. 10-05-006, served July 1, 2011.[29]



The primary conclusion to be drawn from these results is that the higher levels of renewable generation with a 33% RPS portfolio result in reduced generation from the existing fleet of flexible gas-fired resources, which frees up the additional flexibility needed to integrate 33% renewables. This is why integration resources are needed in the "All Gas" 20% RPS

29 R. 10-05-006, ISO Exhibit 2400, page 43.

scenario but not in the 33% RPS cases. This shows that a 33% RPS portfolio will have the needed flexibility, from unloaded existing flexible capacity, provided that flexible capacity is retained on the system. A second, related observation is that the CAISO's High Load scenario showed a need for additional flexible resources, because the higher loads mean that additional gas-fired generation must be operated to serve load, reducing the amount of unloaded, flexible capacity available to integrate 33% renewables. In contrast, this flexible capacity is available in the Commission's base scenarios with lower loads. These results show that the flexible capacity plays other roles besides integrating renewables – for example, such capacity also is important to ensure that resources are available if the 33% RPS goal is not achieved (as in the "All Gas" case) or if loads are higher than expected (as in the High Load scenario).

Flexible gas-fired generation located in load centers also is important to meet local reliability needs. This issue is front-and-center in southern California in Track 1 of the current LTPP case, R. 12-03-014, due to the significant upcoming retirements of existing conventional gas-fired capacity that uses once-through cooling ("OTC"). Further, the return to service of Huntington Beach Units 4 and 5 in 2012 to cover the loss of the San Onofre nuclear units ("SONGS") shows the importance of excess capacity to meet unexpected resource contingencies. The need for new gas-fired capacity to meet all of these needs, of which renewables integration is only one, is being reviewed again in Tracks 1 and 2 of the 2012 LTPP case. Track 1 is reviewing local capacity requirements in southern California resulting from OTC retirements; Track 2 will focus on system needs, including for renewables integration. Whether new flexible resources are needed will depend on the fleet of flexible generation that is available, on the size of the renewable energy portfolio, on local capacity needs, on the future of major resources such as SONGS, and on the expected future demand for electricity. It will be a challenge to isolate which portion (if any) of the future need for flexible resources is attributable to renewables integration. Given the Commission's conclusions in D. 12-04-046 in R. 10-05-006, including the modeling showing that a 33% RPS portfolio will unload adequate existing flexible generation to integrate that amount of renewable generation, CalWEA does not believe that there is a basis at this time to include any long-term capacity costs in an integration adder used for LCBF evaluations. The Commission should re-visit this conclusion only if further studies (for example, the analyses that may be done in Track 2 of R. 12-03-014) show a clear need for long-term resources solely for renewables integration. Otherwise, the Commission should re-visit this issue when planning begins to move to a new RPS goal that is higher than the current 33% by 2020.

The short-term component of the integration cost adder should be the additional ongoing operating costs which the CAISO is incurring to integrate renewables. Such data is beginning to become available. For example, the CAISO has been tracking the costs associated with the Flexible Ramping Constraint ("FRC") which it implemented in January 2012 to ensure that it has adequate ramping capability within each hour to integrate all supplies, including existing renewables. The CAISO also has developed a methodology to allocate FRC costs to load, to supply sources (both conventional and renewable), and to the fixed ramps in self-schedules. Ultimately, the CAISO would use this method to allocate the costs for the Flexible Ramping market product that the CAISO is developing to replace the FRC. The CAISO proposes to initially allocate the costs for the flexible ramping service based upon movements that require changes in real-time dispatch of resources. For load, this would be changes in observed loads every ten minutes. The movement for generation would be the change in uninstructed imbalance energy ("UIE") every ten minutes. Movement for fixed ramps in self-schedules would be calculated based upon the change in MWhs deemed delivered every 10 minutes.

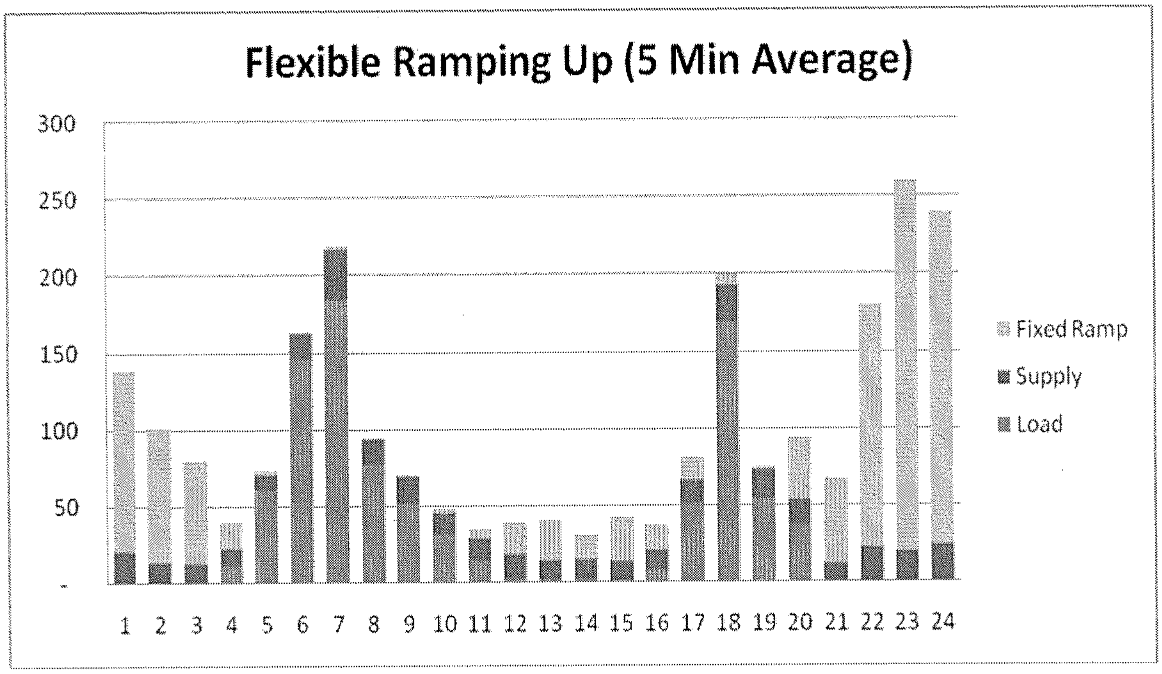
Using this approach, the CAISO has allocated the $5.7 million in FRC costs for the first quarter as follows:

Table 1: Flexible Ramping Constraint Costs – First Quarter of 2012 *($ millions)*

• Source	• FRC Cost (1Q 2012)	• Allocation Method
• Load	• $3.26	• Observed 10-minute load changes
• Supply	• $1.04	• 10-minute change in UIE
• Fixed Ramps	• $1.17	• 10-minute change in MWhs delivered
• Total	• $5.47	•

Source: CAISO, "Flexible Ramping Products - Revised Draft Final Proposal" (dated August 9, 2012, hereafter "*FRP Proposal*"), at 42, reporting on the FRC data from January 1 through March 31, 2012. The CAISO provided CalWEA with the workpapers for this allocation.

Thus, the FRC costs attributable to all supply sources amounted to a little over $1.0 million in the first quarter of 2012, or about 19% of total FRC costs. The following figure shows how the flexible ramping up requirements (in MW) are distributed over the hours of the day.



Source: CAISO, *FRP Proposal*, at 37.

CalWEA has extended the CAISO's allocation method to assign supply-related FRC costs to specific supply sources on the basis of each source's contribution to 10-minute changes in uninstructed imbalance energy, based on the data on 10-minute changes in UIE by supply source in the CAISO's workpapers. The resulting allocations are shown in **Table 2** below, and the final column expresses the FRC costs in $ per MWh of output from each type of supply during the first quarter of 2012.

Table 2: Allocation of FRC Costs to Specific Supply Sources – First Quarter of 2012

• Supply Resource	• FRC Costs *($ million)*	• Generation (GWh)	• FRC Costs *($/MWh)*
• Wind	• 0.227	• 1,760	• 0.13
• Hydro	• 0.244	• 3,648	• 0.07
• Solar	• 0.065	• 167	• 0.39
• Gas	• 0.417	• 23,543	• 0.02
• Baseload*	• 0.083	• 9,164	• 0.01
• Total	• 1.037	• 38,282	• 0.03

* *Baseload resources include geothermal, biomass/biogas, and nuclear.*

CalWEA recognizes that Table 2 is based on just one quarter of data on FRC costs, and that the CAISO is considering other approaches than the change in UIE for allocating these costs among supply sources.[30] Nonetheless, CalWEA presents this allocation to show that actual cost data on the key integration cost for renewables – ramping within the hour – is becoming available from the CAISO, and this data can be further parsed and allocated to specific supply

[30] For example, it may be difficult to measure changes in UIE between 10-minute intervals, so the CAISO is considering the use of gross UIE instead of changes in UIE. Some stakeholders have proposed to allocate these costs based on UIE that falls outside of a certain threshold. There are also important issues concerning the forecast that will be used to measure deviations for variable resources such as wind. See the *FRP Proposal*, at 38-41. CalWEA reserves the right to modify this proposal as more data and analysis become available through the CAISO stakeholder process.

sources to produce metrics that indicate the relative cost of integrating various types of renewable resources.[31] CalWEA recommends that such an approach should be used to develop an integration adder for LCBF purposes that is disaggregated by generation technology. CalWEA expects that a full year of 2012 data on FRC costs will become available in 2013, and that the CAISO will make further progress in developing an approach for allocating these costs among different sources of supply. Once this data is available, CalWEA recommends that the Commission hold a workshop to further develop the methodology for using this data to develop an integration adder that can be used for LCBF evaluations and that allocates short-term integration costs to the various renewable and conventional technologies.

CalWEA strongly recommends that the short-term cost component of any RPS integration adder should be based on the actual FRC costs that the CAISO is incurring to integrate renewables on its system. The Commission should not use "proxy" integration adders derived from studies of other utilities or control areas, which do not reflect the significant portfolio of flexible resources that are available to the CAISO to manage system operating needs – in particular, California's significant hydro resources and it large fleet of gas-fired capacity. CalWEA notes that Table 2 shows that an initial allocation of the FRC costs attributable to existing wind and solar on the CAISO grid are $0.13 per MWh and $0.39 per MWh, respectively. These values are more than an order of magnitude below the $8.50 per MWh "proxy" which PG&E proposed in its most recent RPS plan and which the Commission rejected in D. 12-11-016. Certainly, the values shown in Table 2 will change as the CAISO reports more

[31] CalWEA is presenting these numbers, based on a limited set of FRC cost data from just three months, to illustrate the approach to calculating technology-specific integration adders. CalWEA urges parties to not place undue emphasis on the relative magnitude of the $ per MWh integration adders among renewable technologies in the final column of Table 2, given the limited FRC cost data available. For example, the solar numbers can be expected to change significantly relative to the other technologies with the addition of summer months when solar output is more reliable (i.e. fewer clouds). The solar category also could be disaggregated into solar thermal and solar photovoltaic technologies.

data on FRC costs and as the CAISO and stakeholders refine the methodology to allocate flexible ramping costs to various supply sources. However, this data strongly suggests that the CAISO's ultimate allocation of short-term integration costs to intermittent resources will be far below the magnitude of the adder that PG&E proposed.

Qualitative Factors

As also noted in the response to Number 24 above, the current process already provides a mechanism for consideration of project viability and workforce recruitment, training and retention efforts as qualitative factors that can be used to justify including a project on the shortlist that may not have been included based on pure quantitative considerations. CalWEA recommends continuation of this approach. CalWEA cautions the Commission to avoid allowing the IOUs to represent qualitative factors such as these in quantitative terms. For example, in the recent decision adopting the 2012 RPS Procurement Plans, the Commission agreed to allow PG&E to apply its proposed Portfolio Adjusted Value ("PAV") metric to bids it will receive in its 2012 RPS solicitation. This PAV calculation includes elements like a +$10/MWh value adder for contracts with a 10-year term and a -$10/MWh cost adder for contracts with 25-year terms. To the extent that the energy from a 10-year term is worth more than the energy from a 25-year term, this should already be captured in the ANMV calculation. Otherwise, the $20/MWh spread is purely arbitrary, and would result in PG&E paying $20/MWh more for energy purely for the right to fulfill its qualitative preference for shorter-term contracts. Placing a quantitative value on qualitative preferences results only in eliminating the objective value of the ANMV calculation.

26. For each of these four topics, and for your LCBF proposal as a whole, please explain how your proposal would affect costs ultimately paid by ratepayers for RPS-eligible energy, using quantitative examples where relevant.

Because CalWEA's proposals for revising the ANMV calculation would cause the ANMV calculation to better match the expected cost and value of individual RPS bids, CalWEA's proposal would result in a reduction in the overall RPS costs to ratepayers by causing more efficient projects (from an overall portfolio perspective) to be shortlisted. Greater transparency and reduced subjectivity in the bidding process will also enable bidders to tailor their bids to maximize value, while increasing bidders' confidence in the fairness of the competition. These conditions will improve developer confidence in California's RPS market overall, which will spur investment in project developments that, in turn, will benefit ratepayers by promoting competition.

27. For each of the four topics, and for your LCBF proposal as a whole, please explain how your proposed criteria would contribute to the efficiency of the RPS procurement process.

As noted in the response to Number 26 above, CalWEA's proposals to revise the ANMV calculation would increase the efficiency of the RPS procurement process by causing the LCBF evaluation to highlight lower-cost/higher-value resources that would minimize total costs of RPS procurement. Higher-cost bids would be selected only if the non-energy values they provide are offset by commensurate value.

28. What additional topics, if any, should be part of the LCBF process? Please provide a detailed discussion of each topic, using quantitative examples where relevant.

As noted in the response to Number 24 above, the existing ANMV formula is sufficient, with the modifications suggested herein, to capture all of the quantitative factors that are currently applicable.

K. Green Attributes Standard Term and Condition

The ACR requests comment on the need for revision to the Commission's current Standard Term and Condition 2 (definition of Green Attributes).[32]

> **29. In view of the adoption of RECs as the basis for RPS compliance, is STC 2 still necessary in its entirety? Please explain in detail, with reference to: 1) current commercial practice; 2) the regulatory requirements of the Commission and any other relevant agencies (e.g., the California Energy Commission (CEC) and the California Air Resources Board (CARB)); and 3) recent legislation related to biofuels (Assembly Bill (AB) 1900 (Gatto); AB 2196 (Chesbro); and SB 1122 (Rubio)).**

CalWEA has no comment on the need for revisions to STC 2.

> **30. Are specific elements of STC 2 still necessary? If so, which ones? Please explain in detail, with reference to: 1) current commercial practice; 2) the regulatory requirements of the Commission and any other relevant agencies (e.g., CEC and CARB); and 3) recent legislation related to biofuels (AB 1900 (Gatto); AB 2196 (Chesbro); and Senate Bill (SB) 1122 (Rubio)).**

CalWEA has no comment on the need for revisions to STC 2.

> **31. Even if not necessary, is STC 2, or are some elements of STC 2, still useful in RPS procurement contracts? Please explain in detail, with reference to: 1) current commercial practice; 2) the regulatory requirements of the Commission and any other relevant agencies (e.g., the CEC and CARB); and 3) recent legislation related to biofuels (AB 1900 (Gatto); AB 2196 (Chesbro); and SB 1122 (Rubio)).**

CalWEA has no comment on the need for revisions to STC 2.

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[32] ACR at 38-39.

III. CONCLUSION

For the foregoing reasons, the Commission should adopt the recommendations set forth in these comments.

Respectfully submitted,

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November 20, 2012

VERIFICATION

I, Nancy Rader, am the Executive Director of the California Wind Energy Association. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the foregoing copy of *Comments of the California Wind Energy Association on Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals* are true of my own knowledge, except as to the matters which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on November 20, 2012 at Berkeley, California.

Nancy Rader

Nancy Rader

Executive Director, California Wind Energy Association