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)

REPLY COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON DRAFT 2014 RPS PROCUREMENT PLANS AND RELATED QUESTIONS IN ASSIGNED COMMISSIONER'S RULING

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I. INTRODUCTION

Pursuant to the California Public Utilities Commission's ("CPUC" or "Commission") Rules of Practice and Procedure, the *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2014 Renewables Portfolio Standard Procurement Plans* ("ACR"), the April 16, 2014, email from Administrative Law Judge DeAngelis revising the schedule for this proceeding, and the follow-up questions on integration cost adder issues contained in a July 17, 2014, email from Energy Division staff, the California Wind Energy Association ("CalWEA") respectfully replies to parties' opening comments on the investor-owned utilities' ("IOU") draft 2014 Renewables Portfolio Standard ("RPS") Procurement Plans and the specific topics raised in the ACR for comment by the parties.

II. COMMENTS ON INTEGRATION COST ADDER ISSUES

A. Replies to Follow-Up Questions Posed by Energy Division

1. There is general consensus among parties that an integration adder should be dynamic, updated frequently and differ based on technology and location. Furthermore, most parties agree that an adder should only include the indirect costs associated with integrating variable energy resources such as costs associated with regulation, ramping and cycling. If this is the case, should the term "integration adder" be changed to reflect these agreed upon attributes if what ends up being calculated are unique costs for each technology based on changes in electrical systems' portfolio mixes over time? What is your recommendation and what standard "term" and "definition" do you believe the CPUC should adopt?

In our opening comments at p. 18, CalWEA suggested that the word "component" be used rather than "adder" to reflect the fact that this value is one of several cost components in the "Adjusted Net Market Value" ("ANMV") formula adopted by the Commission in its decision on the 2012 RPS procurement plans, for use in the utilities' least-cost, best-fit ("LCBF") bid evaluation processes.[1] The definition of "integration cost component" should be as articulated in the RPS statute: the "indirect costs associated with … the ongoing electrical corporation expenses resulting from integrating and operating eligible renewable energy resources."[2] The value of this component may vary by technology. CalWEA proposed a methodology for calculating these values in our opening comments, and refines that proposal in these reply comments based on the opening comments of other parties (see reply to Question 8, below).

> ***2. If integration adders were developed in the LTPP Proceeding, would updating the adders best be achieved by including that as part of the biennial LTPP process? If not, what frequency and manner would be ideal? How would those results be introduced into the LTPP record?***

The Commission is obliged by the RPS statute to adopt an integration cost adder (or "component").[3] Therefore, it is reasonable and necessary – indeed, overdue – for the Commission to adopt a methodology for the adder in the instant proceeding. As articulated in our proposal, while the Long-Term Procurement Plan ("LTPP") will be the primary source of the long-term component of the integration cost adder (although the value of that component is likely to be zero for several years), there is no reason at present to evaluate the adder as part of the LTPP process. In our opening comments at p. 26, CalWEA outlined a post-33% RPS planning approach that should make sense in an LTPP context for calculating a proxy for the long-term component of the integration cost adder. While we urge the Commission to consider such broader approaches for the longer-term, the (belated) task at hand is for the Commission to adopt an integration cost adder for RPS procurements, and it should do so immediately, for application in this RFO cycle. Under the methodology that CalWEA proposed, the figures could

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[1] CPUC D.12-11-016, at p. 24 (November 14, 2012).

[2] *See* Public Utilities Code Section 399.14(a)(4)(A)(i). CalWEA also previously noted that pending legislation (SB 1139) would reconstitute this section; however, we believe that, should the legislation be adopted, the rephrasing would not change the meaning of the existing statute or the appropriate methodology.

[3] *Ibid.*

be regularly updated for each RFO cycle by incorporating readily available CAISO and utility data.

> *3. Three general approaches to calculating integration adders were identified by parties – 1) using values from publicly available studies, 2) using market-based cost data from CAISO's regulation and upcoming flexible capacity markets, and 3) using the operational flexibility studies currently scoped in the LTPP proceeding to inform the development of integration adders.* ***Please comment on the advantages and disadvantages of each approach and recommend a procedural framework for implementing your preferred approach. If your recommended framework utilizes more than one approach please be specific regarding the procedural steps and timeline that the CPUC should follow in developing integration adders.***

We reply to each of the specified approaches in turn:

1) *Using values from publicly available studies* – Integration costs will vary dramatically across operating systems due to the market design of those systems, related operating protocols, and renewable energy penetration levels. This wide variation can be seen in the table of integration-cost values shown in Pacific Gas and Electric Company's ("PG&E") opening comments at p. 6-7, where the figures vary by nearly a factor of 20. Further, seven of the 10 studies do not even include an integration cost value for solar. For this reason, CalWEA strongly objects to using figures from other operating areas which will not reflect circumstances in California. Nor is it necessary to use such far-flung data when California-based figures are readily at hand, as indicated in CalWEA's opening proposal (as modified below).

2) *Using market-based cost data from CAISO's regulation and upcoming flexible capacity markets* – Using data from CAISO's regulation and upcoming flexible ramping and flexible resource adequacy ("RA") capacity markets is essentially CalWEA's proposal (as modified below), with additional cost data on existing flexible RA capacity and any long-term new flexible RA capacity costs provided by the utilities. The advantages of this approach are several: (a) it is comprehensive, including all components of the indirect costs associated with the ongoing expenses resulting from integrating renewable energy resources; (b) it reflects real, California-specific costs, rather than speculative or inapplicable costs from other regions; and (c) it is straightforward and relatively simple to implement, largely because the

CAISO has already developed the necessary market protocols and the computational tools, has performed and will continue to perform the necessary analysis, and can be expected to calculate and share the data for the calculation of the integration cost adder.

3) *Using the operational flexibility studies currently scoped in the LTPP proceeding to inform the development of integration adders* – The LTPP studies will inform just one of several cost components of the integration cost value, as explained in CalWEA's opening comments. The LTPP proceeding will determine whether any new flexible RA capacity is needed to integrate renewables. We anticipate that the studies will show that no new capacity is needed to integrate 33% renewables or more at least until 2030; however, if a capacity need is shown due to increased load variability or penetration of renewable resources beyond 33%, this long-term cost component can be readily calculated and allocated to various renewable technologies using data available from CAISO studies as described in CalWEA's proposal (see CalWEA's opening comments at p. 24-26).

> ***4. Do you think it is important for the Commission to determine a methodology for the development of integration adders as well as calculate the values to be used in LCBF? Or is it more appropriate that the IOUs be responsible for calculating integration cost adders based on the methodology developed by the CPUC? Please recommend your preferred approach by weighing the strengths and weaknesses of allowing for IOU-based values. In considering your recommendation, how important is it that the values calculated be verifiable by parties?***

CalWEA has proposed a methodology that lends itself to straightforward, transparent implementation of the integration cost component of the ANMV formula. Most of the cost and cost allocators would come directly as public information from the CAISO's regular studies. The cost of flexible resources from existing or new facilities would be provided by the utilities based on their latest flexible RA capacity procurement cycle, and should be averaged across all of the utilities (as integration costs are generally a system-wide phenomenon). Thus, provided that the utilities are required to make public every cost element in their integration cost adder calculation, we would not object to the Commission leaving to the utilities the task of calculating, and annually updating, the integration cost component as part of their annual procurement plans.

5. ***Do you think it is important for the CPUC to adopt a methodology to calculate integration adders in time for the 2014 RPS Solicitation beginning in early 2015? If so, can any of the three general approaches mentioned in Question 3 meet this objective while also providing reasonable and defensible cost estimates? In addition, do you believe integration adders, if calculated using one of the three approaches, will be significant enough to alter procurement decisions?***

Yes, it is important for the CPUC to adopt a methodology for application in the 2014 solicitation cycle. We agree with Brightsource, in its opening comment at p. 9, that "ignoring available information, including evolving information derived from other proceedings, risks increasing integration costs unnecessarily by failing to differentiate between resources that will add to, or subtract from, those costs."

To summarize what we explained in our opening comments (at p. 27): First, the RPS statute has required consideration of indirect integration costs since 2002. Second, it is now readily possible to calculate these costs, as we have explained. Third, assumptions are being made that the integration cost value could be large enough to change bidding outcomes, particularly between variable and baseload renewable resources, [4] with such assumptions driving calls for technology-specific legislative mandates in the absence of consideration of indirect costs.

CalWEA does not expect that the indirect integration costs associated with wind and solar PV resources will be high enough to bridge the gap between much higher cost baseload renewable or solar thermal technologies. However, the indirect costs of wind and solar PV, while relatively small, could be significant enough to affect IOU procurement decisions among wind and solar PV resources.

Regarding the reasonableness and defensibility of the cost estimates that would be produced under CalWEA's proposed methodology, it is difficult to imagine a methodology and resulting estimates that would be more reasonable and defensible, given that the figures would be based on data associated with the actual operations of the market in which CPUC-jurisdictional

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[4] For example, the opening comments of the Center for Energy Efficiency and Renewable Technologies ("CEERT"), at p. 19, quote comments filed by the Green Power Institute in this proceeding, stating that "a 'functioning LCBF methodology that truly balanced best-fit with least-cost would surely produce a more diverse outcome.'" CEERT suggests, at p. 24, that in the absence of an integration cost adder, the utilities be allowed to "assess the composition" of their renewables portfolio to include resources such as geothermal to reduce flexibility requirements.

utilities operate. While (as we indicated at p. 23 of our opening comments) the "medium-term" cost element (the utilities' cost of securing existing RA resources to provide flexible capacity) may not be available until the 2015 bidding cycle, the Commission can reasonably proceed this year without that element (i.e., initially and temporarily assessing that cost at zero), unless the IOUs are able to propose defensible figures. Finally, as we also indicated in our opening comments, the Commission also should not wait until the 2014 LTPP studies are available, as it is highly unlikely that a need for new flexible capacity (the long-term cost component within CalWEA's proposal) will be demonstrated for purposes of achieving the 33% RPS in 2020.

6. ***In its comments, PG&E provided a framework for calculating integration adders using production cost modeling. If parties agree that production cost modeling should be utilized to determine the costs associated with integrating renewables, do you agree with the framework that PG&E has proposed? Are there any modifications to the framework that you would make? If so, provide a modified framework in your response.***

CalWEA agrees that production cost modeling should be used in determining integration costs, but such modeling is already used by the CAISO to develop the factors for determining and allocating integration costs, which are incorporated in CalWEA's proposed approach. As part of its Flexible Ramping Product ("FRP") and Flexible RA Capacity and Must-Offer Obligation ("FRACMOO") market initiatives, the CAISO has already begun performing and will continue to perform such modeling, both to determine the amount of flexible capacity that is needed and to allocate that need among the factors causing it (both load and resources). This is done on the basis of the past year (for the FRP market) and two years ahead (for the FRACMOO market) – i.e., essentially based on the current portfolio, as compared to PG&E's proposal to base a new modeling effort on some future year. While PG&E's proposal could theoretically be more accurate, it would necessarily be more speculative (and thus more controversial). It would also take a significant amount of time and resources to conduct this new and complex modeling effort, and will thus delay the use of integration values in the bidding process. Moreover, we would not expect the extra effort to produce dramatically different results, compared to those coming out of CAISO studies, for procurements in the 2020 timeframe.

7. ***Integration costs may rise as the saturation level of renewable resources increases over time. If production cost modeling is used to assist in developing integration adders, what level of renewable saturation should be assumed and what is your rationale?***

As noted in our answer to the previous question, it is not necessary, for the immediate purpose of developing an integration cost adder for the 2014 procurement cycle, to look ahead to forecast and estimate integration costs based on future penetration levels. However, as a part of longer-term planning efforts aimed at levels of renewables above 33%, a different (and far more complex) approach could and eventually should be taken, as we proposed in our opening comments beginning at p. 26. However, at this point, there is no legislative or Commission policy to support such an approach; therefore, the Commission should adopt a more straightforward and readily achievable approach for application in the immediate term.

8. ***In its comments, CalWEA provided a framework for calculating the short-term, medium-term and long-term costs associated with renewable integration. Please comment on the practicality of this framework and whether you think it could meet the objective of developing integration adders that are reasonable and defensible. What refinements need to be made to the proposed framework for it to achieve the stated objectives?***

As stated above in answer to question 5, CalWEA believes that its proposed methodology is practical, reasonable, and defensible. Several parties commented that the methodology should reflect system-wide conditions and the overall portfolio,[5] which CalWEA's methodology does, as it is based on CAISO system information. The conceptual approach outlined by Calpine (which owns both gas and geothermal resources) is very similar to the methodology proposed by CalWEA (the approaches described by the utilities are also conceptually similar – see Section II.B. below).

In response to Calpine's opening comments at p. 6, we agree that the short-term cost component of CalWEA's integration cost formula should be refined to include regulation costs (i.e., the cost to respond to variations in resources within a five-minute timeframe). However, we disagree with Calpine's suggestion that regulation costs should be allocated uniformly across all intermittent renewable resources. Wind and different types of solar resources, particularly on a location-specific basis, do not equally demand regulation service. If the CAISO is able to generate updated renewable-resource-specific regulation-cost figures in time for the 2014 RFO

[5] *See, e.g.*, UCS opening comments, at p. 4; Iberdrola opening comments, at p. 3.

cycle,[6] that cost element should be included in the integration cost figures this year; otherwise, it should be incorporated into the 2015 cycle.

With regard to locational factors, CalWEA agrees with PG&E (at p. 10-11) that the integration cost calculation should "strike a balance between the level of granularity … and the effectiveness of the results it produces." One issue that could conceivably significantly affect integration costs, and thus warrants attention, is the well-known impact of solar PV energy variability in coastal areas, due to cloud cover, compared with that of desert solar projects. This locational impact should be addressed if possible. The CAISO is readily capable of further parsing its regulation service, FRP and FRACMOO cost allocations on a meaningful geographical basis, such as coastal/non-coastal areas. However, if the CAISO cannot accomplish this for the 2014 RFO cycle, the Commission should proceed in 2014 without the locational nuance and address it in 2015.

B. Replies to Opening Comments on Integration Cost Issues

The integration cost methodology proposed by CalWEA is similar in concept to those described in the comments of Southern California Edison Company ("SCE")[7] and PG&E,[8] and very closely tracks Calpine's proposal (at p. 5), which proposes that the integration cost adder should include the cost of regulation, the CAISO's proposed FRP, and Flexible RA capacity "to the extent that the costs of any of these products reasonably can be ascribed to a renewable resource." CalWEA's opening comments (at p. 22-24) point to the fact that the CAISO has already ascribed the cost of these grid services to load, wind and solar resources. We encourage the CAISO to expand its methodology to better distinguish among CSP and solar PV technologies as well as coastal and desert renewable resource project locations. In response to Energy Division question #8, above, we agreed with Calpine that the integration cost adder

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[6] We note that the need for regulation service will be reduced due to the introduction of the CAISO's FRP.

[7] *See* SCE opening comments, at p. 3: "SCE proposes that four major components be included in an integration cost adder methodology: (1) increases in wear and tear … for conventional resources; (2) increases in reserves required to offset the increased intermittency and unpredictability of renewable generation; (3) increases in flexible RA capacity requirements …; and (4) any need for construction of new generating facilities beyond the increases identified above."

[8] *See* PG&E opening comments, at p. 3: "[A renewable integration cost adder should include:] Costs incurred to address renewable forecast uncertainty…; Costs incurred to address the hour to hour and multi-hour variability …; [and] Costs incurred to address intra-hour variability."

should include the cost of regulation, and we hereby incorporate that element into the short-term cost element of our proposal as described above in our reply to Energy Division Question 8.

All three utilities – PG&E at p. 2, SCE at p. 4 and San Diego Gas & Electric Company ("SDG&E") at p. 5 – state that the increased costs from more frequent cycling of conventional resources should be included in the integration cost value. We agree; however, generation owners can be expected to factor these costs into the bids they submit into the CAISO's and the utilities' markets for regulation, flexible ramping, and flexible RA capacity services. The costs of all of these grid services are captured in CalWEA's proposed methodology.

SCE refers (at p. 5) to the CAISO's development of the FRP in its discussion of "operational reserves" needed for renewables, as well as an NREL study of five hypothetical renewable energy penetrations on the Western grid, which SCE suggests should be used until FRP costs are available, along with other more general sources of information. As we explained in our opening comments, while the FRP initiative is not expected to be final until the end of this year, the CAISO has already provided proxy costs for FRP based on the costs associated with its Flexible Ramping Constraint, which costs could be used for the short-term cost element of the integration cost adder. Thus, there is no need to use the results of hypothetical studies from regions other than that in which the California investor-owned utilities operate.

Indeed, while SCE references various studies and refers to various costs in various terms, there are only two general categories of renewable energy integration costs: variability and uncertainty. All such operational costs have been identified by the CAISO and have been or soon will be quantified in the form of regulation, FRP and flexible RA. Any new capacity needs will be identified in the CPUC's LTPP proceedings. All of these costs are accounted for in CalWEA's proposed methodology. We strongly disagree with SCE (at p. 8) that it "is difficult to quantify and standardize" integration costs "necessitating the continued use of a qualitative assessment in the LCBF process." The Commission should prohibit the addition of any costs that, to paraphrase Calpine (above) "cannot reasonably be ascribed to a renewable resource." Nor is there a need to "recreate the wheel" as PG&E proposes to do, because the work has already been done by the CAISO.

Lastly, we note that the Large-scale Solar Association ("LSA"), at p. 12, indicates that it would support a methodology based on CAISO values, at least for interim use.

III. REPLIES TO PARTIES' COMMENTS ON CAPACITY VALUATION

The ACR asked (at 19-20) whether there is any justification for including a positive value to system RA in the 2014 RPS procurement processes given that the Track 2 of the 2012 LTPP proceeding found no need for the procurement of additional system capacity. CalWEA's opening comments (at p. 8) effectively replied with a "no," stating that, while there is a need for local and flexible capacity (which will simultaneously provide system capacity), there is no need to procure additional generic system capacity from renewables or any other resource.

CalWEA suggested (at p. 10) an alternative approach: that the parties to a power purchase agreement ("PPA") can negotiate appropriate terms to enable the project to provide system capacity in the future, should it become needed before the end of the term of the PPA, and/or projects can offer their system RA capacity in separate procurement processes for that capability.[9] In this way, system capacity can be procured *if and when needed* at appropriate prices, and ratepayers can benefit from competition among all available sources of such capacity. Thus, the value of capacity can be determined in the market when the need arises, rather than administratively and speculatively determined by the utilities in advance.

Several parties argued that, despite a clear lack of need for system RA capacity, some positive value is warranted, for a variety of reasons that we respond to after summarizing them as follows.

(1) ***"Sufficient capacity may exist, but it will need to be procured."*** SCE, for example, states at p. 9 that "Even if an LTPP does not find a need for *incremental* system resources, it does not guarantee that the resources assumed to continue to operate are indeed still available. The continued operation of such facilities is assured, in part, by load-serving entities performing forward procurement … and in part, by the RA requirements that are designed to ensure that a sufficient amount of capacity has been procured and made available to the CAISO in order to reliably operate the grid." Similarly, CEERT states at p. 21 that the "[RA] capacity of a new RPS eligible facility is always valuable whether the system has need for new capacity or not. At a minimum, contracting for a new RPS eligible facility with RA value allows the Load

[9] To the extent that developers believe, with any degree of certainty, that their system RA capacity will become valuable in the future, they can account for such value in their anticipated revenue stream.

Serving Entity (LSE) to let its most expensive existing RA contract lapse. The RA value of a new RPS eligible facility should be the marginal cost of existing RA contracts for that LSE."

Response: Even if existing capacity will need to be procured in the future, the need is likely to be for local and/or flexible capacity, not for generic system RA capacity. The local capacity additions that will result from the 2012 LTPP Track 1 and 4 decisions, as well as capacity additions stemming from the storage mandate – both of which will simultaneously provide system capacity – make it unlikely that any additional system resources will be required at least through 2030, as shown in the planning assumptions and scenarios adopted for use in the 2014 LTPP.[10] In the 2012 LTPP, Track 2 (addressing system and system flexibility needs for the next 10-20 years) was cancelled due to indications that the need "may be low or non-existent depending on the level of local capacity procurement authorized in Track 4."[11]

(2) ***"A need may exist that is not yet reflected in the LTPP findings."*** Calpine states at p. 2 (and LSA suggests similarly at p. 5-6) that the planning assumptions and scenarios adopted for use in the 2014 LTPP, which show no need for system RA capacity until 2030, are not accurate because they over-count the capacity of wind and solar resources, which will be addressed in the Commission's RA proceeding when an effective load carrying capacity ("ELCC") valuation methodology is adopted and implemented.

Response: While CalWEA agrees that the ELCC methodology is likely to significantly reduce the capacity value of solar resources, there are countervailing considerations. First, a simple examination of the CAISO's generation interconnection queue and utilities' WDAT queues shows that significant RPS resources have completed their Phase 2 studies and can achieve deliverability status upon COD and completion of their network deliverability upgrades, if any, but have not yet been contracted. If procured through the 2014 RPS (or later) solicitation processes, these resources will be able to participate in any future RA capacity

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[10] *See* CalWEA's opening comments, at p. 9 footnote 21.
[11] *See* R.12-03-014, *Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and Track 4 Schedules*, at p. 6 (September 16, 2013).

procurement processes. Second, based on the CAISO's generation interconnection protocols, RPS resources with interconnection studies completed prior to 2012 that did not receive deliverability status have the option to apply for and receive deliverability status as long as they do not trigger transmission upgrades.[12] Once these resources obtain deliverability status (and hence become eligible for system RA capacity) they will be eligible to participate in future RA capacity procurement processes. Finally, projects queued in 2012 or later that can achieve deliverability status without major transmission upgrades will receive such status, making them eligible to participate in the upcoming RA capacity procurement processes.[13]

(3) "***A lack of capacity need will be appropriately reflected in low values.***" SCE states, at p. 9, that "if the Commission is concerned that the calculation of benefits will be overstated …, the Commission should recognize that SCE calculates this value quantitatively, and if the amount of resources available to meet the system RA is indeed a surplus, one would expect that the prices for system RA would decrease ..." Similarly, PG&E argues, at p. 13, that "If the system is long on capacity, the market value of system capacity is expected to be based on the going-forward fixed costs of maintaining a fossil generator in the market, net of energy market revenues. Even in the current market which has capacity in excess of the 15% Planning Reserve Margin, capacity prices have been and continue to be positive."

Response: Clearly, the utilities would prefer to be able to continue to devise their own capacity values in a process that heretofore has been neither transparent nor scrutinized by the Commission.[14] Moreover, the common theme in the parties' comments summarized here is that the need for and value of system RA at this time is undefined and uncertain and, thus, highly speculative. There exists a very high likelihood that no "generic" system RA capacity will be needed for many years to

[12] *See* CAISO tariff language for its Generation Interconnection and Deliverability Allocation Procedures, Section 9.2. Available at: http://www.caiso.com/Documents/GIDAP-TariffAmendment.pdf.
[13] *Id.* at Section 7.2.
[14] To wit, in the 2013 RFO cycle, CalWEA objected to SDG&E's clear over-market valuation of capacity (multiples of then-recently reported median RA prices) to no avail. (We note that the other utilities did not publicly provide their proposed values at all.) *See* CalWEA's July 12, 2013, comments in this proceeding, at p. 18-19.

come, if at all. Should the Commission allow positive system RA capacity values to be used, therefore, it should not give the utilities *carte blanche* to do so. Enabling the utilities to devise their own system RA values runs the risk that they will set those values too high, essentially transferring the risk of potentially stranded investment in system RA capacity to ratepayers, and inflating the cost of the RPS policy. Thus, the Commission should either administratively determine any system RA capacity values to be used, or it should require the utilities to submit transparent and well-supported capacity valuations for review.

In addition, any approved positive values should be known to bidders. As CalWEA has argued in previous years, 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. The interconnection process presents 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 Energy Only without RA capacity and avoid certain transmission upgrade 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 upgrades. 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.

IV. CONCLUSION

For the reasons stated in CalWEA's opening comments and the foregoing additional reasons, the Commission should schedule a workshop to discuss CalWEA's proposed integration cost component methodology (as refined herein) for application in the 2014 RPS RFO cycle, and should set the capacity value at zero for the 2014 RPS RFO cycle.

Respectfully submitted,

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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 *Reply Comments of the California Wind Energy Association on Draft 2014 RPS Procurement Plans and Related Questions in Assigned Commissioner's Ruling* 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 July 30, 2014 at Berkeley, California.

Nancy Rader

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Nancy Rader

Executive Director, California Wind Energy Association