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 INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON PROPOSED DECISION ACCEPTING RPS PROCUREMENT PLANS

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SUMMARY OF RECOMMENDATIONS

For the reasons explained in more detail in these comments, the Independent Energy Producers Association respectfully recommends that the Commission:

- Clarify that renewable resources will be compensated for unknown future costs of renewables integration that are allocated to them, and approve IEP's proposed contract language for inclusion in the utilities' pro forma agreements;
- Require Southern California Edison Company to conduct a 2012 Renewable Portfolio Standard solicitation or if SCE is excused from conducting a 2012 RPS solicitation, allow SCE to contract with renewable resources based on bilateral negotiations;
- Reject the 12-month limit for concluding negotiations after the shortlist from a solicitation is submitted to the Commission, but create incentives that encourage both parties to arrive at a prompt conclusion of negotiations;
- Allow sellers to bundle renewable energy with Resource Adequacy capacity purchased from third parties; and
- Order Pacific Gas and Electric Company to modify its curtailment provision to narrow the circumstances when curtailments are required.

2970/010/X145508.v1

TABLE OF CONTENTS

Page

2970/010/X145467.v3

TABLE OF AUTHORITIES

Page

DECISIONS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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The Independent Energy Producers Association (IEP) has previously submitted comments and reply comments on the Renewable Portfolio Standard (RPS) procurement plans of the large electric utilities. IEP's previous comments raised a number of concerns about the plans, and some of IEP's concerns were reflected in the *Proposed Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Off-Year Supplement,* issued by Administrative Law Judge Regina DeAngelis on October 9, 2012 (PD). In these comments on the PD, IEP will focus on a few specific issues.

I. THE PD ERRS BY FAILING TO CONSIDER CONTRACT LANGUAGE ON THE ALLOCATION OF POTENTIAL RENEWABLES INTEGRATION CHARGES

To support the integration of intermittent renewable resources into the electric grid, the California Independent System Operator (CAISO) is proposing to charge the costs of any integration services the CAISO finds necessary to the Scheduling Coordinator (SC) for renewable supply resources. While the SC for renewable supply resources may be the utility, this is not always the case. Furthermore, even if the utility is the SC for the resource, this fact alone does not necessarily resolve the cost allocation problem raised by the CAISO's proposal to impose integration costs on resources selected by the utilities to meet their RPS obligations.

Under the CAISO proposal, intermittent renewable generators selected to meet the utilities' RPS obligation face the risk of increased and unanticipated integration charges over the term of their contracts with the utility, which can be for 20 years or longer. Because these proposed CAISO-imposed integration charges are currently unknown and unknowable to renewable developers, the risk of bearing these costs in the future creates a very real barrier to the development of renewable energy projects. For example, financing renewable projects will become increasingly more expensive if generators are exposed to the risk of these unknown costs over the duration of the contract. This risk is particularly chilling for project development because nearly all renewable development in California is premised on a long-term contract, typically on a fixed-price basis, to provide a steady revenue stream that can convince investors to finance the project. To the extent that the future revenue stream is threatened by future CAISO integration charges, lenders will require a greater risk premium which will be reflected in a higher bid by the seller. Customers will unnecessarily face higher costs that could be mitigated if integration costs are allocated at the outset to the buyer that selected the renewable resource.

In its comments on the RPS procurement plans, IEP recommended including a non-modifiable contract term in the pro forma RPS contract.[1] The language IEP recommended was:

> Unless otherwise specified in this Agreement, any charges imposed on Seller by the CAISO, pursuant to its tariff, to recover costs that the CAISO determines are required to integrate increasing levels of renewable resources into the CAISO-controlled transmission system shall be compensated by Buyer.

[1] *Comments of the Independent Energy Producers Association on the RPS Procurement Plans,* June 27, 2012, pp. 9-10.

In light of the CAISO's proposal to impose integration costs on renewable supply resources, the PD errs by failing to address this issue. Because the utilities used their own Least-Cost/Best-Fit (LCBF) methodology to select these resources, any increased costs associated with CAISO integration services should properly be borne by the entity that "caused" the costs, *i.e.,* the utility that selected the resource. Once integration costs are included in the resource selection process, resources with the lowest integration costs will be appropriately recognized and the impacts on the electric grid should be ameliorated. In the meantime, by ensuring that these unanticipated costs will be fully compensated by the utility, the Commission will send the proper price signals to buyers (and therefore the marketplace) who determine what types of resources are selected and ultimately built to serve California consumers.

II. SCE'S PROPOSAL TO SKIP A 2012 RPS SOLICITATION AND THE BAN ON BILATERAL CONTRACTING

Southern California Edison Company (SCE) proposes not to hold an RPS solicitation for 2012. SCE proposes to meet any unmet RPS compliance needs during the period covered by its RPS procurement plan by procuring energy from renewable facilities of less than 20 MW. The PD accepts SCE's proposal, but also bars SCE from pursuing bilateral, negotiated power purchase agreements (PPAs) until this restriction is removed in future decisions.[2] In this passage, the PD errs.

A. SCE Should Conduct a 2012 RPS Solicitation

As a practical matter, the Commission's decision to reserve a portion of the RPS program for smaller-scale renewable resources will likely increase the costs of overall RPS compliance. The best means to mitigate the effect of these higher costs is to continue to regularly procure renewable resources, regardless of size or technology, on a LCBF basis. Thus,

[2] PD, pp. 51-55.

the PD's conclusion to accept SCE's proposal to skip its 2012 RPS solicitation is short-sighted in several respects:

- Even a solicitation for a relatively small amount of renewable generation would provide additional information about the current market price of renewable energy. When the utilities skipped the 2010 RPS solicitations, the market-based standard for evaluating projects proposed in 2011 continued to be the results of the 2009 solicitation, even though market conditions were much different in 2011 than they were in 2009.
- Eliminating the 2012 RPS solicitation effectively precludes California consumers from benefitting from the availability of the 30% federal investment tax credit. To qualify for the credit, projects must begin commercial operation by 2016, and a solicitation in 2012 is critical to meeting that schedule. There is no assurance that the investment tax credit will be extended, so skipping the 2012 RPS solicitation could become a significant missed opportunity for California ratepayers.
- Maintaining a schedule of regular annual solicitations provides regulatory and market certainty that tends to lower the costs of development. Project development is not a spigot that can be readily turned on or off; the early stages of project development include the difficult tasks of acquiring a site, putting together a financing plan, and obtaining an interconnection agreement. Before taking these costly steps, developers need some certainty as to when the utilities will conduct another competitive solicitation.

- Conducting a 2012 RPS solicitation allows for the possibility that a particularly attractive project or superior technology will emerge.
- Conducting a 2012 RPS solicitation will enable the utilities to replace the MW from recently rejected projects with projects that better align with the Commission's LCBF approach. The Commission has declined to approve some RPS PPAs stemming from the 2011 RPS solicitations. On October 25, for example, the Commission decided not to approve PPAs SCE proposed for 600 MW of renewable energy. Rejected or cancelled projects create a gap in the utility's procurement plan that can be filled through a 2012 solicitation.
- As contracts for renewable resources expire over the next few years, a regular RPS solicitation provides an opportunity for project owners to bid repowers for future years and allows suppliers with expiring contracts to decide whether to make capacity investments. It should be noted that repowering of old renewable Qualifying Facilities (QFs) is often complicated and can take years to orchestrate.

SCE's rationale for its request is that its forecasts show that it has no need for additional renewable resources through 2016. However, even SCE's forecasts show a need starting in 2017 (even before the recent rejection of PPAs totaling 600 MW). Furthermore, holding a solicitation in 2012 for projects that will commence deliveries in 2017 or later is practical and consistent with the Commission's efforts to secure the highest-valued resources at the lowest cost to ratepayers. A regular annual RPS solicitation, conducted in compliance with LCBF procurement principles, captures potential ratepayer savings while providing the utility the tools to retain maximum procurement flexibility to respond to changing demand patterns, project cancellations, and rejected contracts.

B. <u>Bilateral, Negotiated Contracts Should Be Allowed</u>

Because SCE requested the authority to skip the 2012 solicitation, the PD bars SCE from considering offers for bilateral contracts. "Without a solicitation," the PD argues, "the Commission will not be able to adequately determine the reasonableness of bilateral contracts as no comparable market data for SCE will exist for the Commission to compare with the bilateral contract."[3] The solution to this problem, of course, is for SCE to hold a solicitation, as IEP recommends above.

Even in the absence of a solicitation, however, there are numerous other sources of available market information that should provide guidance to the Commission as it evaluates bilateral contracts. For example, the Commission will have access to the results of the solicitations conducted by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company. In addition, the Renewable Auction Mechanism (RAM) solicitations provide market information about smaller renewable projects (20 MW or smaller) that is indicative of the broader market price for renewable energy. The Re-MAT program and SCE's Solar Photovoltaic Program will provide additional information about the market price of renewable power.

Although the best option is still to require SCE to conduct a 2012 RPS solicitation, the absence of a solicitation does not require or justify a prohibition of bilateral agreements. Opportunities that arise between solicitations can provide significant value to the utilities and their ratepayers, and the PD should be modified to allow developers to bring projects

[3] PD, p. 55.

forward and to authorize the utilities, including SCE, to contract with these projects, even if the agreement is arrived at through bilateral negotiations.

Furthermore, the Commission should not foreclose creative contracting options that may allow utilities to capture the benefits of the expiring investment tax credit, allow existing resources to repower in the future, or hedge an unusually high failure rate or an unexpected need for additional resources. At the federal level, there are proposals concerning the Production Tax Credit (PTC) for wind that expires in December 2012 that would allow projects that start construction in 2013 to capture the PTC. If Congress passes legislation to renew the PTC, particularly a short-term extension, the Commission should not limit its ability to consider proposals that could allow ratepayers to benefit from discounted renewable energy prices reflecting the credit. These short-term tax opportunities could be particularly important for older California wind facilities that have repowering opportunities and contracts that expire in the coming years.

IEP notes that the Commission originally proposed a ban on bilateral contracting for projects for the RAM. After reconsidering the ban in response to petitions for modification filed by IEP and NextEra Energy Resources, the Commission reversed itself and recognized the potential benefits of retaining the option to negotiate a contract outside of the preferred framework of a competitive solicitation.[4] Specifically, the Commission found that (a) prohibiting bilateral contracting limited the procurement and contracting options of the utilities and project developers; (b) the prohibition on bilateral contracting may prevent some developers from participating in the market altogether and may pose substantial barriers to amending or extending existing contracts; (c) it was not clear that eliminating the prohibition on bilateral contracting would adversely impact the level of competitive pressure in each RAM solicitation;

[4] Decision (D.) 11-04-008.

and (d) allowing bilateral contracting or other contracting options for projects otherwise eligible for RAM is unlikely to dilute or reduce the benefits of RAM.[5] Similar logic should apply now in the context of the utilities' RPS solicitations.

Finally, if the Commission authorizes SCE to skip the 2012 RPS solicitation, it should require SCE to conduct an RPS solicitation as early as possible in 2013 and specify the month in which the solicitation will commence to provide some clarity and certainty to developers of renewable resources.

C. In the Absence of an RPS Solicitation, UOG Projects Should Not Be Considered

In D.12-04-046, the Commission determined that it would consider proposals for utility-owned generation (UOG) projects only if there had first been in the context of a "failed RFO." If the Commission accepts the PD's recommendation to allow SCE to skip its 2012 RPS solicitation, the PD should also clarify that SCE may not propose a UOG RPS project until it has completed its next RPS solicitation.

III. THE 12-MONTH LIMITATION ON NEGOTIATIONS

The PD approves a proposal to require the utilities' shortlists to expire 12 months after the utility submits the shortlist to the Commission. The goal of this provision appears to be to encourage the parties to negotiate and execute contracts within that 12-month period so the Commission has the benefit of current market information.[6]

The 12-month period might encourage shortlisted projects to complete negotiations promptly. However, as proposed, this provision has some critical shortcomings. First, the PD states that shortlisted projects must have competed a Phase II transmission impact

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[5] D.11-04-008, p. 12 (Findings of Fact Nos. 1-4).
[6] PD, pp. 31-34.

study "in order for a contract to be executed."[7] The Phase II study process is lengthy and subject to delays that are entirely outside of the project's control. The interaction between the PD's requirement for a completed Phase II study and the expiration of the shortlist after 12 months could mean that viable, cost-effective projects would be rejected because of delays in the CAISO's transmission impact study process, **not** because of the merits of the project or the actions or inactions of the project developer.

If a project is already shortlisted, the CAISO proposes to complete the Phase II study within 205 days, or just under seven months, at which time the CAISO would deliver the study results to the interconnecting customer. However, other requirements and contingencies can lengthen the CAISO interconnection study process to ten months or more. In addition, the factors that delay completion of the Phase II study are likely to be outside of the individual bidder's control. Delays can result from the complexities associated with the "cluster study" approach recently initiated by the CAISO, in which multiple projects are studied simultaneously and in parallel.

Shortlisted bidders should not be deselected and eliminated from the shortlist unless the bidder explicitly takes some action that causes the project to miss the Phase II study window (*e.g.,* failing to make a required financial posting for study costs, or violating the study agreement in some other fashion). On the other hand, if the delay is caused by an unplanned delay in the CAISO study process due to actions beyond the control of the developer, then the Commission should not deselect a bidder whose Phase II study took more than 365 days to complete from the date the shortlist was submitted to the Commission.

In addition, the effect of the 12-month limitation is asymmetrical, to the detriment of the shortlisted renewable projects. Negotiations involve two parties—the project and the

[7] PD, p. 41.

utility. If negotiations are not concluded with 12 months, under the PD's resolution the utility would be barred from executing a bilateral contract with the same project, and the project could be bid into the next RPS solicitation. Thus, the project developer could lose 12 months (and longer if the 12-month period extends beyond the bid date of the next solicitation) and still not gain a PPA. The utility, in contrast, loses an opportunity to negotiate a PPA with the project, but can replace the lost energy in the next solicitation.

The PD's approach would give undue leverage to the utilities, because the utilities have the primary role in controlling the timing and pace of the negotiations. The 12-month limitation could put developers under pressure to acquiesce in the utility's proposals as the deadline approached, because acquiescence might be the only way a developer could avoid further delay and receive some compensation for its project. Unfortunately, while obtaining last-minute concessions from the developer may be tactically advantageous to the utility in its negotiations, these last-minute concessions may also reduce the viability of an otherwise viable project.

Rather than taking an approach that punishes the developer by eliminating its project from consideration, even when the delay is beyond the control of the developer, IEP suggests that the Commission should consider creating incentives to encourage a prompt conclusion of negotiations. For example, the Commission could establish an incentive mechanism to financially reward the utility for completing negotiations with shortlisted projects. If both parties have a roughly equal incentive to complete negotiations within the 12-month period, the PD's proposed deadline may serve its intended purpose.

IV. RESOURCE ADEQUACY FROM THIRD PARTIES

The PD rejects SCE's proposal to allow sellers to bundle renewable energy with Resource Adequacy (RA) capacity from third parties because "the record is currently insufficient to assess the risks and benefits to ratepayers and to the RA market of permitting a seller to provide substitute resource adequacy through short-term arrangements compared to contractual agreements that provide long-term resource adequacy."[8] This reasoning fails to survive scrutiny.

First, the concern about short-term versus long-term RA capacity overlooks the fact that RA capacity currently is a one-year product, which is inherently short-term. While some resources may be presumed to offer "long-term resource adequacy," it is impossible to determine with certainty that a particular long-term resource will continue in future years to qualify to provide RA capacity. From a conceptual perspective, a facility offering "long term resource adequacy" is actually proposing to offer a succession of one-year RA contracts for as long as it can maintain the assumed level of net qualifying capacity.

Second, the PD fails even to mention that allowing third-party RA capacity to be bundled with renewable energy may often be the least expensive way for a remote renewable resource to meet contractual requirements without incurring huge expenses for transmission network upgrades, which in many cases will ultimately be borne by ratepayers. Rather than requiring a distant generator to upgrade its transmission links to the rest of the grid, under SCE's proposal it could provide the same reliable energy and capacity products without the cost of the network upgrades.

Third, this proposal has been fully vetted as part of this proceeding, and any significant risks associated with this arrangements would have emerged by now. The proposal is an innovative way to address the potentially large costs of transmission upgrades for remote renewable energy projects, and the Commission should not hesitate to approve the bundling of renewable energy and third-party RA capacity.

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[8] PD, p. 58.

V. THE PD IS LOGICALLY INCONSISTENT IN ITS TREATMENT OF INTERCONNECTION COSTS

The PD accepts new terms in the utilities' pro forma agreements to allow for contract termination if transmission upgrade costs exceed expectations.[9] Specifically, the PD concludes that this new term represents a reasonable means of limiting the total RPS procurement costs to ratepayers by linking termination rights to negotiated caps on transmission network upgrade costs. The PD authorizes the utilities to incorporate terms into their pro forma agreements regarding termination rights and buy-down provisions if the results of any interconnection study or agreement indicate that network upgrade costs will exceed a specific amount agreed to by seller and the utility.

In its earlier comments, IEP raised several concerns about this provision. In light of other conditions imposed on developers in the bid solicitation process, the proposed termination and buy-down rights appear increasingly redundant and unnecessary, while they impose a risk on developers that they cannot hedge easily.

The PD already requires the developer to have fully completed its CAISO Generator Interconnection Process Phase II study before executing its contract. The Phase II study is the most detailed and extensive available study of interconnection costs. Thus, under this new provision, both the Buyer and Seller will have the best available estimate of interconnection and transmission upgrade costs when they finalize and execute the contract. It is inconsistent to require a completed Phase II study as a pre-condition for executing a contract while allowing for contract termination if the final interconnection costs exceed estimates based on the best information available at the time.

[9] PD, pp. 29-31.

In addition, typically the utility is the entity that actually builds the interconnection facilities. As a result, the utility has considerable control over the pace, scale, and cost of transmission upgrades. Imposing the risk of contract termination on the developer if transmission costs exceed a specified amount, when the developer does not control those costs, is unnecessary and unwarranted, especially since estimated transmission costs should be incorporated in the utilities' LCBF bid evaluation process.

Accordingly, if a completed Phase II study is required prior to contract execution, pro forma language to allow for contract termination if the costs of transmission upgrades exceed a specified limit should not be required.

VI. THE PROPOSED DECISION FAILS TO ADDRESS A KEY CURTAILMENT ISSUE

The PD errs by failing to address a significant issue related to PG&E's curtailment proposal raised by IEP and other parties, even though this proposal could have costly effects on consumers.

Both IEP and the California Wind Energy Association (CalWEA) noted that PG&E's proposed curtailment provisions could result in PG&E having an unlimited ability to curtail generators without compensation. This outcome results from PG&E's expansive definition of "Curtailment Order" to include any warning, forecast, or anticipated overgeneration condition. The CAISO, however, expects to resolve most potential overgeneration situations through market mechanisms, not by issuing warnings, until it encounters actual overgeneration. Under PG&E's definition, a generator could be curtailed without compensation even as other generators are receiving compensation for curtailing in response to market signals.

PG&E's proposal goes well beyond what might be reasonable required to maintain the reliability of the grid. The risk of excessive curtailments posed by PG&E's

proposal will ultimately be reflected in higher bids in the RPS solicitations and in higher costs for consumers as the utilities procure resources to meet their RPS requirements.

VII. CONCLUSION

For the reasons stated in these comments, IEP respectfully urges the Commission to modify the PD in the following ways:

- Clarify that renewable resources will be compensated for unknown future costs of renewables integration allocated to them;
- Require SCE to conduct a 2012 RPS solicitation, or, alternatively, allow SCE to contract with renewable resources based on bilateral negotiations;
- Reject the 12-month limit on negotiations but create an incentive that encourages both parties to arrive at a prompt conclusion of negotiations;
- Allow sellers to bundle renewable energy with RA capacity purchased from third parties;
- Reject proposals that allow for contract termination if transmission upgrades exceed expectations; and
- Order PG&E to modify its curtailment provisions.

Respectfully submitted this 29th day of October, 2012 at San Francisco, California.

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By *_/s/ Brian T. Cragg_*
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VERIFICATION

I am the attorney for the Independent Energy Producers Association in this matter. IEP is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of IEP for that reason. I have read the attached "Comments of the Independent Energy Producers Association on Proposed Decision Accepting RPS Procurement Plans," dated October 29, 2012. I am informed and believe, and on that ground allege, that the matters stated in this document are true.

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

Executed on this 29th day of October, 2012, at San Francisco, California.

/s/ Brian T. Cragg
Brian T. Cragg