STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

Implementation of Renewables Portfolio Standard Legislation (Public Utilities Code Sections 381, 383.5, 399.11 through 399.15, and 445; [SB 1038], [SB 1078])	)	Docket No. 03-RPS-1078
Implementation of Renewables Investment Plan Legislation (Public Utilities Code Sections 381, 383.5, and 445; [SB 1038])	)	Docket No. 02-REN-1038

COMMENTS OF THE UTILITY REFORM NETWORK ON PROPOSED CHANGES TO THE RENEWABLES PORTFOLIO STANDARD GUIDELINES AND PROCUREMENT VERIFICATION REPORT

Matthew Freedman
The Utility Reform Network
711 Van Ness Avenue, Suite 350
San Francisco, CA 94102
(415) 929-8876
December 9, 2005

COMMENTS OF THE UTILITY REFORM NETWORK ON PROPOSED CHANGES TO THE RENEWABLES PORTFOLIO STANDARD GUIDELINES AND PROCUREMENT VERIFICATION REPORT

In response to the November 30 notification of proposed guidebook changes involving the Renewables Portfolio Standard (RPS) program, The Utility Reform Network (TURN) submits these comments on the draft RPS program guidelines. TURN appreciates the work done by CEC staff to address a few key policy, reporting and verification issues which must be resolved quickly in order to facilitate RPS procurement by investor-owned utilities (IOUs) and other retail sellers. While some of the changes proposed in the guidebooks are reasonable, others require additional clarification, and some should be modified. In addition, the Commission must address the fundamental disconnect between the 10-year limitation on Supplemental Energy Payment (SEP) awards and the need for such funds to cover above-market costs for power purchase contracts of up to 20 years.

I. THE COMMISSION SHOULD NOT PUBLICLY DISCLOSE ANY AGGREGATED DATA ON THE RESULTS OF UTILITY SOLICITATIONS UNTIL NEGOTIATIONS WITH ALL PROJECTS SELECTED FOR CONTRACTS IS COMPLETE

The New Renewable Facilities (NRF) program guidebook proposes to require IOUs to submit certain data to the CEC after selecting an initial short list of bidders in a solicitation. For bids below the applicable Market Price Referent (MPR), the data would be aggregated for "the total number of facilities, the weighted average price of the bids, the amount of electricity bid, the percentage of the IOU's APT represented by the bids, and the percentage of the generation bid that would require new transmission."[1] For short-listed projects with prices above the MPR, the IOU would be required to submit data on these particulars for each bid. The guidebook claims that such information "is necessary for the Energy Commission to make informed decisions when allocating SEPs

[1] NRF draft guidebook, page 10.

to individual applicants."

TURN does not object to the requirement that aggregated data be provided on sub-MPR shortlisted bids so long as the Energy Commission does not disclose such data publicly until all utility negotiations with short-listed bidders are complete. The release of such data during the negotiation process could be very harmful to ratepayer interests. It should be obvious that any bidder possessing this information while negotiating with an IOU would have an unfair advantage which could result in higher ultimate prices. There is no obvious reason why the public stands to benefit from such an approach.

To the extent that the Energy Commission intends to immediately disclose all data it receives, including the particulars of every supra-MPR bid, TURN believes such a requirement would be very detrimental to the RPS program. To date, the CEC has failed to identify any compelling rationale for adopting a policy of radical transparency. Adopting an extreme disclosure requirement at this juncture will only result in delays, litigation, and additional focus on process rather than results.

TURN agrees that there is too much confidentiality surrounding procurement and has worked with the CPUC and IOUs to increase the amount of information publicly disclosed. But TURN disagrees with the proposition that individual bids submitted by developers and all final contract prices should be made public. Transparent pricing, coupled with inflexible and escalating demand for renewable power, could result in price manipulation, gaming and higher costs. Rather than releasing too much information to the companies seeking to profit from the RPS program, TURN supports an incremental approach to disclosure.

If the CEC intends to pursue the approach outlined in the draft guidebooks, TURN recommends that all data submitted to the CEC be subject to confidential treatment and that information be publicly released only <u>AFTER</u> aggregating the solicitation information provided by all IOUs and other retail sellers. In other words, public disclosure should be limited to the combined results of all solicitations and not released on a buyer-specific basis. So long as the data is fully aggregated and held in confidence until the conclusion of all relevant negotiations, the public release of summary results is unlikely to harm ratepayer interests. Aggregation protocols should ensure that a sufficient number of data points are available prior to any public release.

II. THE GUIDEBOOKS FAIL TO RESOLVE CONCERNS OVER AWARDING SUPPLEMENTAL ENERGY PAYMENTS FOR CONTRACTS LONGER THAN 10 YEARS

The draft guidebooks do not resolve concerns over the disconnect between the 10-year SEP awards permitted under statute and the need for funds to cover up to 20-years of above-MPR contract prices. It appears that SEP awards will be based on the difference between the total price and the MPR over a 10-year period. The proposed CEC-SEP-3 form also specifies that, for contracts lasting up to 20 years, prices will be levelized over the entire 20-year duration with payments calculated based on the differences over the first 10 years. Unless this methodology is changed, the SEP award process is unlikely to allow any retail seller to execute a contract longer than 10-years if the project requires SEPs.

Under the proposed approach, a developer offering a project at prices in excess of the MPR would only be able to recover its needed revenues for the first 10 years of a contract. When confronted with this method of calculating SEPs, developers assuming a fixed price in excess of the MPR for a period of 15 or 20 years are unlikely to proceed with project development. The obvious solution to this problem is for the CPUC and CEC to develop a methodology which calculates a net present value of the MPR and bid prices over the entire term of the contract and provides front-loaded SEPs over the first 10 years to make the seller whole. The draft guidebooks fail to explain how its proposed SEP methodology will resolve this concern.

Unlike the CEC, the CPUC already recognized and addressed this issue in its RPS proceeding (R.04-04-026). In D.04-07-029, the CPUC noted the broad recognition amongst a wide array of parties that the disconnect between 20-year contracts and 10-year SEPs must be resolved.[2] This decision adopted the position that "the SEP award should be reduced to reflect its value over the full contract term, as opposed to the 10-year duration of SEP payments."[3] The draft guidebooks do not reference this decision or explain why the CEC is disinclined to adopt a similar approach.

If the Commission does not structure SEP awards to cover the full above-MPR costs of a long-term contract (with IOU responsibility remaining capped at the MPR), there is little chance that any contracts of greater than 10 years with supra-MPR pricing will be executed. Based on conversations with many project developers, it is clear that most projects will not be able to proceed if a significant portion of anticipated future revenues becomes unavailable. Moreover, if the SEP awards are not adjusted to take this problem into account, both sellers and buyers will have significant incentives to game the contract and bid prices.

TURN strongly urges the CEC to modify the guidebooks to adopt an approach which allows the full above-MPR costs of a 20-year contract to be provided through SEP awards paid out over a 10-year period. The mechanics are not difficult, and the failure to make this change would needlessly place many long-term contracts at risk.

[2] This concern was identified by TURN, the Independent Energy Producers, Pacific Gas & Electric, Southern California Edison, and the Office of Ratepayer Advocates.
[3] D.04-07-029, page 18-19.

III. THE GUIDEBOOK SHOULD CLARIFY WHETHER CHANGES TO THE DELIVERY REQUIREMENT FOR OUT-OF-STATE FACILITIES ARE INTENDED TO RESOLVE CONCERNS ABOUT THE RELEVANT "HAND-OFF" POINT BETWEEN BUYER AND SELLER

One set of modifications to the RPS program guidebook involve "delivery requirements" for out-of-state renewable energy projects contracting with a California retail sellers. Based on a review of these changes, TURN cannot determine whether the draft guidebook provides adequate flexibility to allow a California retail seller to take delivery at a point outside the state but receive RPS credit only to the extent that energy from that project subsequently arrives at a market hub or substation within the ISO control area. In order to facilitate out-of-state transactions, the Energy Commission should provide sufficient flexibility with respect to the "hand-off" point between buyer and seller. So long as the physical energy is delivered into California consistent with the NERC tag transactions identified in the guidebooks, the CEC should allow the buyer to assist in the process of providing adequate transmission from an out-of-state market hub to facilitate delivery into California.

The problem with requiring sellers to deliver to an in-state market hub boils down to concerns over the lack of long-term inter-zonal transmission rights within the California ISO. Under current ISO rules, sellers can only acquire firm transmission rights on an annual basis and therefore cannot predict the cost of delivering energy over a potentially congested path outside of the current year. This means that out-of-state renewable generators will be forced to take unpredictable congestion risks in future years and factor such costs into its bid price.

The alternative approach, which may (or may not) be enabled by the guidebooks, would allow a California buyer to take delivery at an out-of-state market hub (such as the California-Oregon Border interface) and then bring the energy into the CAISO control area using transmission rights acquired by the buyer. TURN hopes that the

CEC intends to allow this approach under the guidebook revisions although it is not clear whether these changes accomplish such a result.

The CEC should clarify whether it intends to allow such transactions to qualify under the RPS as part of any final edits to the revised guidebooks.

Respectfully submitted,

MATTHEW FREEDMAN

Attorney for The Utility Reform Network
711 Van Ness Avenue #350
San Francisco, CA 94102
Phone: 415-929-8876

Dated: December 9, 2005