

**BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking to)	
Implement the California Renewables)	R. 04-04-026
Renewable Portfolio Standard Program)	
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**Comments of the California Wind Energy Association
on Time-of-Delivery Market Price Referents and the
Least Cost Best Fit Methodology**

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On Behalf of
THE CALIFORNIA WIND ENERGY ASSOCIATION

February 11, 2005

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**Comments of the California Wind Energy Association
on Time-of-Delivery Market Price Referents and the
Least Cost Best Fit Methodology**

The California Wind Energy Association (CalWEA) respectfully submits the following comments on the calculation and use of Time-of-Delivery (TOD) Market Price Referents (MPRs) in California’s Renewable Portfolio Standard (RPS) program. CalWEA submits these comments in accordance with the Assigned Commissioner’s Ruling (ACR) of December 16, 2004 and the one-week extension of time granted by ALJ Allen on January 25, 2005.

The MPR benchmarks will determine the maximum prices that utility ratepayers will pay for new renewable generation that the state’s investor-owned utilities (IOU) will procure under the state’s RPS legislation. Pursuant to Decision (D.) 03-06-071, the MPRs are to be calculated for three different contract terms—10, 15, and 20 years—for each of two products — baseload and peaking. Thus, there will be six MPRs used in each RPS solicitation.

CalWEA notes that the CPUC Energy Division released a staff report on February 5, 2005 on the calculation of these MPRs. The staff’s MPR estimates, based upon a levelized gas cost of \$5.60 per MMBtu, are shown in the following table:

Table 1: 2004 Market Price Referents (\$/MWh)

Resource Type	10-year	15-Year	20-Year
Baseload MPR	56.1	56.2	56.3
Peaking MPR (5x8)	107.9	108.3	108.5

CalWEA supports the use of TOD MPRs—along with payments that are differentiated using the same factors—because, properly constructed, they would (1) encourage the selection of resources with greater on-peak production, (2) encourage production during on-peak hours, (3) address the problem of applying the baseload or peaking MPR to products that are neither strictly baseload nor peaking, and (4) provide greater transparency to the assessed value of power in different time periods. These important benefits likewise support, even require, a congruent time-differentiated approach to the least-cost, best-fit (LCBF) methodology because it is essential that a proposed project be evaluated consistently with how it will be paid, both to achieve true LCBF results and to avoid the potential for gaming.¹

In its Phase I reply brief on least-cost best-fit issues, Pacific Gas & Electric (PG&E) suggested that TOD MPRs could be constructed using the peaking MPR for the peak hours to which that MPR applies, then deriving an MPR for other hours such that the annual average MPR equals the baseload MPR. CalWEA has considered this approach, but does not support it, for several reasons. First, given the MPRs that have been adopted, and the relatively small number of hours allocated to the peaking product, the MPR in other mid- and off-peak hours would be low—about \$40 per MWh.² In effect, this method would allocate all of the baseload plant’s capacity-related costs to the peak hours. Unlike a peaking plant, a baseload plant can and will recover its capacity-related costs over many more hours than just the limited number of peak hours. Thus, CalWEA

¹ The Commission’s July 8, 2004, decision on the LCBF methodology (D.04-07-029 at pp. 23-28) indicates that the TOD MPR issue is closely related to the LCBF methodology.

² Thus, the “peak” MPR of \$108 per MWh would be 193% of the average baseload MPR, while the “non-peak” MPR of \$40 per MWh would be 72% of the average baseload MPR. CalWEA has calculated the same ratios using hourly prices from the California Power Exchange (PX) in 1999. In that year, the 5x8 PX price averaged 126% of the annual average PX price, while the PX price in all other hours was 87% of the annual average price. This shows that PG&E’s method would yield TOD MPRs that are far “peakier” than recent market experience.

believes that a TOD MPR for a baseload plant that is based on the peaking MPR would result in an unrealistically “peaky” TOD profile for the baseload MPR. If the IOUs want peaking generation, they should contract with renewables that offer a peaking product; they should not try to force baseload resources toward the cost and operating profiles of a peaker through the use of very “peaky” TOD MPRs.

Second, an important characteristic of peaking facilities is the absence of generation during non-peak hours. This provides operational advantages for the utility and justifies the full recovery of all costs—including fixed operating costs—during the few peaking hours. For baseload facilities, this characteristic is absent.

CalWEA does believe that the baseload MPR should be “shaped” to reflect the different value of power in different time-of-delivery periods, but not to the extreme extent of PG&E’s suggestion. Instead, for the purpose of calculating TOD MPR estimates, CalWEA recommends applying to the Baseload MPR (e.g. \$56 per MWh) the time-of-use (TOU) factors that are used for time-differentiating the short-run avoided cost energy prices paid to Qualifying Facilities (QFs). These TOU factors reflect each utility’s avoided costs on a TOD basis, as reflected by the ratio of system Incremental Energy Rates (IERS) for the TOD periods. Furthermore, although the present QF TOU factors have not been updated for many years, the updating of these factors is an issue in the Avoided Cost OIR (R. 04-04-025).³ Thus, CalWEA expects that the Commission will have the chance to review and approve new QF TOU factors this year.

The current TOU factors applied to SRAC energy prices are shown below:

³ For example, one possible approach to revising the TOU factors would be to use the TOU profile of hourly California Power Exchange prices in 1998-1999. This approach has been used recently in the E3 Report that the CPUC commissioned on a long-run avoided cost methodology. “A Forecast of Cost Effectiveness of Avoided Costs and Externality Adders,” prepared by Energy and Environmental Economics (the “E3 Report”), released January 8, 2204 to parties in R. 01-08-028.

Table 2: SRAC TOU Factors (\$/MWh)

	PG&E	PG&E	SCE	SCE	SDG&E	SDG&E
	Summer	Winter	Summer	Winter	Summer	Winter
On-Peak	1.065	NA	1.4251	NA	1.059	1.165
Mid-Peak	1.022	1.032	<i>calculated</i>	1.2185	1.028	1.136
Off-Peak	<i>calculated</i>	<i>calculated</i>	0.8526	<i>calculated</i>	0.889	1.038
Super Off	0.946	0.950	NA	0.776	0.750	0.864
Average	1.000	1.000	1.000	1.000	0.931	1.049

The factors listed as “calculated” are determined each month based on the number of days and hours in each month, such that the average TOU factor for the month is one.

Thus, the SRAC TOU factors have the advantage that they are intended to reflect the TOD value of power. The SRAC TOU factors also are tailored to each utility’s time-of-delivery periods and will reflect each utility’s unique cost and load profiles—utility-specific details that are not reflected in the peaking MPR. For example, the staff report assigns a 23.3% capacity factor to the peaking MPR resource. It is not immediately clear how to translate this price and level of operation into a set of TOD MPRs that reflect each utility’s already-defined TOD periods. Furthermore, CalWEA’s recommendation to make use of SRAC TOU factors has the advantage of promoting greater consistency between the various measures of avoided cost—a stated goal of the Avoided Cost OIR.

In addition, it is very important for potential bidders to know, in advance of each solicitation, how the MPRs will be time-differentiated, and that bid prices also be time-differentiated using the same factors.⁴ This information will allow bidders to structure their bids to reflect the value of the power in different time periods. In contrast, under PG&E’s method that uses the peaking MPR, bidders would not know exactly how the baseload MPR would be time-differentiated until after bids are submitted and the baseload and peaking MPRs are made public. In sum, the use of the SRAC TOU factors would provide certainty and transparency to the process of time-differentiating the baseload MPRs, and would more closely align the baseload MPR with the differing value of power through the course of a day and a year.

⁴ We are assuming that PG&E was not proposing that bidders be allowed to bid two prices—one for the peak hours and one for the baseload hours. Otherwise, one could have the perverse result of a utility selecting a baseload bid that is the lowest over all hours, but that requires PGC funds during off-peak hours, while rejecting another baseload bid that is higher over all hours but that would not need PGC funds in any hour.

The ACR asks for comments on the impacts of TOD MPRs on the administration of PGC funding. CalWEA believes that implementing the SRAC TOU factors would be straightforward, both for the CPUC and the CEC, so long as the same set of TOU factors is applied to both the MPRs and the bid prices. The CPUC would simply multiply the annual average baseload MPR by the TOU factor appropriate to each TOU period, to get the MPR specific to that period. The utilities would apply the same TOU factors to the bid prices they receive. To administer SEP funds, instead of comparing a single bid price to a single MPR, the CEC would simply compare a project's bid price in each TOU period to the MPR specific to that TOU period. If the amount of SEP funds awarded to a bidder must be capped, the caps could be based on a simpler comparison of the non-time-differentiated MPRs and bid prices. The SRAC TOU factors are well-known and have been used for SRAC pricing for many years. The TOU periods are used for both QF pricing and in retail electric rates for large customers. The utilities already meter and pay their QFs on the basis of deliveries by TOU period; the same systems could be adapted to pay baseload RPS projects using the same TOU periods.

Finally, the ACR asks parties to opine on whether TOD MPRs are consistent with the RPS statutes. P.U. Code Section 399.15(c) requires the Commission to determine the MPRs considering, among other things, "the value of different products including baseload, peaking, and as-available output." The value of such products is dependent on the time of day that the products are delivered; thus, CalWEA believes that TOD MPRs are consistent with the statute.

CalWEA also believes that the Commission should consider requiring all of the utilities to employ a congruent time-differentiated approach to the least-cost, best-fit (LCBF) methodology, such as PG&E's LCBF methodology. In particular, the Commission should require that the utilities evaluate TOD adjusted cents/kWh bids against a forward price curve. The Commission also may want to consider requiring the utilities to construct that curve using the same TOD factors that are used to adjust both the MPRs and bid prices. This approach, essentially the one employed by PG&E in its most recent solicitation,⁵ has many benefits.

⁵ PG&E included a "best fit" adder in its evaluation process, however, which appears unnecessary and could distort the results of the methodology.

First, it inherently reflects the value of capacity and sends appropriate price signals to bidders. A bidder, for example, that is confident that it will deliver energy during the more valuable time periods can expect to receive a higher bid score (and greater contract revenues) for its more valuable capacity than a bidder that may not deliver as much during the peak periods.

Second, the approach minimizes the opportunity for gaming that is presented by a bid evaluation methodology that includes separate bids for capacity and energy. As the Commission will recall, the gaming of separate energy and capacity bids was a major problem during the Biennial Resource Plan Update solicitation in the early 1990s. A PG&E-type of approach ensures that a proposed project is paid consistently with how it was evaluated, and that the utility gets the product that it anticipated.

Third, such an approach to LCBF will promote consistency across RPS applications, MPRs, LCBF and contract payments. As discussed above, this a goal that the Commission is pursuing in R.04-04-025.

CalWEA appreciates the Commission's attention to these comments, and looks forward to continuing to provide the Commission with input on RPS-related matters.

Respectfully submitted,

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