

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

Order Instituting Rulemaking to Establish Policies and
Cost Recovery Mechanisms for Generation Procurement
and Renewable Resource Development.

Rulemaking 01-10-024
(Filed October 25, 2001)

OPENING BRIEF OF THE CALIFORNIA WIND ENERGY ASSOCIATION
ON THE IMPLEMENTATION OF THE
CALIFORNIA RENEWABLES PORTFOLIO STANDARD PROGRAM

Joseph M. Karp
Enoch H. Chang
White & Case LLP
Three Embarcadero Center, Suite 2210
San Francisco, California 94111
Telephone: (415) 544-1100
Facsimile: (415) 544-0202
jkarp@whitecase.com
echang@whitecase.com

Attorneys for the California Wind Energy
Association

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I. INTRODUCTION AND SUMMARY

Pursuant to Rule 75 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Wind Energy Association ("CalWEA") submits its opening brief on the implementation of the California Renewables Portfolio Standard ("RPS") Program. In this opening brief, CalWEA presents its proposals on the RPS issues that should be addressed by the Commission on or before June 30, 2003, and explains why the Commission should adopt CalWEA's proposals.

As discussed in detail below, CalWEA makes the following primary proposals.

Benchmark Principles

- The Commission should employ a single methodology and consistent underlying economic assumptions for all of the benchmarks to be adopted.
- The Commission should limit its benchmark methodology to three basic renewable products: firm capacity, unit-contingent capacity, and as-available capacity.
- The Commission should disaggregate its benchmarks into an energy component and a capacity component.

Cost-Based Benchmark

- In the absence of, or to supplement, benchmarks based on contract prices obtained by the utilities in their general procurement process for comparable products, the Commission should adopt a cost-based benchmark.
- The cost-based benchmark should be based upon the costs of a new combined cycle gas fired plant.
- The first step is to determine the all-in costs- of the combined cycle plant, using the determinants proposed by CalWEA and current gas price data.
- The capacity benchmark should be established based upon the capital and fixed O&M costs of a new combustion turbine (“CT”).
- The energy benchmark should be the difference between the all-in costs of the combined cycle plant and the capacity benchmark, and should be time-differentiated.

Least-Cost / Best-Fit

- The Commission should define least-cost / best-fit as the renewable resources that best meet the utility’s expected future energy, capacity, ancillary service and local reliability needs, at the least cost on a net present value basis. The analysis should be based on the combination of renewable and nonrenewable resources that (i) satisfies the renewables procurement requirements of the RPS Program (ii) meets the utilities’ electrical needs and (iii) minimizes total costs.
- The Commission should require the utilities, in their solicitation, to consider bids from all renewable resources (and if possible, non-renewable resources simultaneously).
- The utilities should seek three basic products from renewable suppliers: firm capacity, unit-contingent capacity, and as-available capacity.
- The renewable resource bids must be evaluated on a total cost basis, including the cost of both energy and capacity payments plus any additional indirect transmission and integration costs. Capacity payments need to be converted into actual expected capacity payment amounts based upon expected plant performance.
- Transmission costs and cost responsibility should, if possible, be determined prior to the bids in an expedited Commission proceeding per CalWEA’s proposal in I.01-11-001.
- If transmission costs have not been adopted by the Commission, the utilities should estimate such costs using pre-approved methodology.
- For transmission costs with network benefits, the costs should be shared by all existing and future resources on a per kW basis.

Flexible Compliance, RECs and Penalties

- The Commission should support development by the Energy Commission of an accounting system based on renewable energy credits (“RECs”).
- The utilities should have a three-month true-up period at the end of each year.
- The utilities should have a five-percent “safe harbor” deficit allowance each year.
- The utilities should have unlimited credit banking, but only if the Commission clarifies that the utilities must continue to procure at least 20% from renewable resources after 2017.
- A utility should be permitted to defer compliance only if it can justify, and the Commission approves, compliance deferral to achieve least-cost / best-fit benefits. Deferrals should be approved where (i) the results of the least-cost / best-fit bid evaluation demonstrate that substantial benefits can be captured through a deferral and (ii) contracts are being signed for future deliveries that will bring the utility into compliance as planned.
- The Commission should adopt specific and automatic noncompliance penalties for a utility’s failure to meet its annual procurement target (“APT”) on a per-kWh basis, after taking compliance flexibility measures into account. The penalties should significantly exceed the expected cost of compliance, and the payments of penalties should not excuse the utility from making up the shortfall in the following years. The penalty revenue should be deposited in the public goods charge (“PGC”) fund.

Standard Terms and Conditions

- The Commission should adopt standard form contracts for three renewable products: firm capacity, unit-contingent capacity, and as-available capacity.
- The Commission should adopt a standardized solicitation process.
- The Commission should adopt consistent contract terms and conditions among all utilities, unless there is an articulated reason justifying different contract terms among the utilities.
- The Commission should not require additional credit support for the utilities (assuming that the utilities have an investment-grade credit rating) or the renewable bidders beyond an “earnest-money” deposit to be paid by the winning bidder.
- The Commission should accommodate the scheduling of renewable power either by requiring the utilities to act as scheduling coordinators (“SCs”) for the renewable generators or to allow financial settlement with renewable generators in their portfolio.

- The Commission should allow only the contract price and project-identifying information be kept confidential. All other information, including summary pricing (without attribution to a particular project) and any negotiated terms, should be available to the public.

II. DISCUSSION

In accordance with California Public Utilities Code Section (“§”) 399.14(a)(2), the Commission is required by June 30, 2003 to adopt: (A) a process for determining market price benchmarks; (B) a process that provides for rank ordering and selection of the least-cost and best-fit renewable resources on a total cost basis; (C) flexible rules for utility compliance with RPS mandates; and (D) standard terms and conditions to be used by utilities in contracting with renewable suppliers. CalWEA’s proposals on each topic are addressed in order below.

Prior to addressing each individual topic, however, it is important to recognize the substantial overlap among the different topics and the need to develop a coherent policy that integrates the benchmark methodology with the least-cost / best-fit process and standard contract terms and conditions. CalWEA’s proposal, for example, would establish market price benchmarks that correspond directly to three standard contractual products, which products are evaluated using consistent economic assumptions in the least-cost / best-fit process. This kind of integration is absolutely essential for a successful implementation of the RPS process, as we explain below.

It is also necessary for the Commission to balance the utilities’ claimed need for flexibility and discretion in implementing the RPS program against the legitimate need for consumers and renewable resource advocates to understand how the RPS program is to be implemented and to ensure that it is done so fairly and responsibly. This requires a significant degree of transparency and standardization. While it would not be prudent to completely divest the utilities of discretion, the Commission must refrain from allowing the utilities the freedom that they seek to implement the RPS program through the proverbial “black box.”

A. MARKET PRICE BENCHMARKING

Pursuant to § 399.15(c), the Commission's market price benchmark methodology must determine the market price of electricity for terms corresponding to the length of contracts with renewables in consideration of the following:

- the long-term market price of electricity for fixed-price contracts, determined pursuant to the utilities' general procurement activities authorized by the Commission;
- the long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities; and
- the value of different products including baseload, peaking, and as-available output.

CalWEA, through the testimony of its witness R. Thomas Beach, proposes a methodology for setting market price benchmarks that meets the applicable requirements and should be adopted by the Commission. *See CalWEA/Beach, Exhibit ("Ex.") RPS-12, Chapter ("Ch.") 1, at 1-7.*

1. **The Commission's Benchmark Methodology Should Correspond to CalWEA's Three Underlying Principles**

Before addressing the specifics of CalWEA's proposed benchmark methodology, it is critical that the Commission employ the three basic benchmark methodology guidelines proposed by CalWEA's witness, Mr. Beach.

First, for all of the benchmarks to be adopted (both for an individual utility and among the utilities), the Commission should employ a single methodology and employ consistent underlying economic assumptions. *CalWEA/Beach, Ex. RPS-12, Ch. 1, at 1.* This is necessary in order to ensure that PGC funds are allocated rationally among various products and among different utilities. If products are evaluated using different methodologies or economic assumptions, it could be that one is valued more than another based upon mere methodological differences, rather than upon the inherent value of the product. Uniformity and consistency will also lend credibility to the process and allow for greater transparency. CalWEA recognizes that each utility will present different circumstances and certain market price determinants may vary across the State. Any adopted methodology, therefore, should be sufficiently flexible to accommodate these differences;

nevertheless, the same basic benchmark methodology and assumptions should be adopted for each utility and for each product. As discussed below, CalWEA's proposed benchmark methodology is sufficiently flexible to allow for both uniformity across products and utilities and to accommodate differences in circumstances.

Second, the Commission should limit its benchmark methodology to three basic renewable products: firm capacity, unit-contingent capacity and as-available capacity. *Id.*¹ This is necessary to comply with § 399.15(c)(3), which requires differentiation by product,² and to ensure that the benchmarks are grounded in reality and are not merely fictitious – undefined – market price projections. In other words, it is necessary to answer the question: to what product does the market price correspond? In addition, by tying the benchmarks to a set of three basic products, the Commission can ensure that the benchmarks actually correspond to the products being offered by renewable suppliers. For example, as discussed below, CalWEA proposes that the Commission adopt standard contract terms and conditions for three basic products, the same products for which benchmarks should be adopted: firm capacity, unit-contingent capacity and as-available capacity. Finally, it would be impossible to attempt to establish benchmarks and standard contract terms for every possible product or product variation that could be sought or offered. As such, the Commission should limit its efforts to a manageable set of basic products.

Third, the Commission should disaggregate its benchmarks into an energy component and a capacity component. *Id.* The energy component would be the same for all products (on a seasonal and time-differentiated basis), reflecting simply the market value of a kWh of energy at a given point in time. Time differentiating an otherwise uniform energy price allows the Commission to compare the relative value of resources that offer more energy in high value (peak) periods and those that offer more energy in the lower value (off-peak)

¹ More detail concerning what is meant by firm capacity, unit-contingent capacity and as-available capacity is provided below under the discussion of standard contract terms and conditions.

² § 399.15(c)(3) refers specifically to “different products including baseload, peaking, and as-available output”. As discussed below, CalWEA's proposal incorporates the differences between baseload and peaking output by time-differentiating the energy and capacity payments. CalWEA's proposal has the added benefit of acknowledging, and valuing, the differences between baseload and peaking suppliers that make firm commitments and those that do not.

periods, without making over-general assumptions about renewable technology deliverability characteristics. The capacity component would reflect the different commitment that each supplier makes to deliver energy, based upon the performance requirements contained in the standard contract terms and conditions, firm being the highest commitment and as-available the least.³ Again, this method allows the Commission to compare the relative value of individual resources in a coherent and unbiased manner.

With these three underlying principles, the Commission may adopt a benchmark methodology that is credible and grounded in reality, that appropriately differentiates among different products and that is integrated with other components of the RPS program.

2. The Commission Should Adopt CalWEA's Proposed Benchmark Methodology

In order to establish specific benchmarks for the renewable products, § 399.15(c) points the Commission to two specific sources of information: (1) the fixed prices contained in long term contracts entered into by the utilities as part of their general procurement activities, and (2) the costs associated with new generating facilities.

As Mr. Beach points out, the most straightforward way to develop market price benchmarks would be to rely upon the prices obtained by the utilities in their general procurement processes for products that are comparable to those being sought from renewables.⁴ *CalWEA/Beach, Ex. 12, Ch. 1, at 2.* However, this method may not always be available, as the utility may not seek renewable products at the same time as it undertakes general procurement activities, or it may not seek comparable products from renewables and non-renewables. *Id.* As several witnesses pointed out during cross-examination, there is unlikely to be a resource need in the near-term for the type of products that renewable generators provide. *See e.g.,* Edison witness Lars E. Bergman, Reporter's Transcript ("Tr.") at 2672-2674; Beach, Tr. at 2982; and TURN witness William B. Marcus, Tr. at 3167. It is

³ As discussed below, however, CalWEA's proposal is to pay renewable suppliers for capacity the same amount as is developed for the capacity benchmark, adjusted for contract delivery requirements. Thus, there is no need to actually distinguish among the separate capacity benchmarks, as the energy-only benchmark will suffice for PGC allocation purposes.

⁴ By "comparable," CalWEA means a signed contract of the same duration for the same product and having similar terms and conditions.

also possible that only a limited amount of comparable contracts are entered into, and additional data may be required in order to ensure that the benchmarks are truly robust. As a result, the Commission should establish benchmarks based upon the costs of new generating facilities for use when the market price information is not available or is inadequate. These cost-based benchmarks could be used in lieu of or as a supplement to the contract-price based benchmarks.⁵

As described by Mr. Beach, and as virtually all parties agreed, the cost-based benchmark should be based upon the costs of a new combined cycle gas fired plant. *CalWEA/Beach, Ex. RPS-12, Ch. 1, at 2. See also ORA/Smith, Ex. RPS-39, at 5-7; TURN Ex. RPS-25, at 10-16; and CEERT Ex. RPS-1, at II-4.* This reflects the fact that most new non-renewable generation facilities being constructed in California today are combined cycle gas fired plants. *CalWEA/Beach, Ex. RPS-12, Ch. 1, at 2.*

The first step in developing the benchmark would be to determine the all-in costs of a combined cycle plant, including variable operating costs, fixed capital and operating costs, emissions offset costs and line loss costs. *Id.* Table 1 of Mr. Beach's testimony, reproduced as Appendix 1 to this brief, presents the key parameters of the all-in combined cycle costs, with proposed values for a number of the variables. *Id. at 3.* These values are derived from a variety of sources, including Commission and California Energy Commission sources, and should be adopted by the Commission at this time. *Id.* Applicable gas prices and transportation rates would be incorporated into the benchmark calculation based upon the most recent available data. Employing gas prices between \$4.00 and 5.00 per MMBtu, CalWEA's proposed all-in combined cycle costs would be between \$57.42 and \$65.38 per MWh. *Id. at 4.*

Once the all-in costs of the combined cycle plant have been determined, the next step is to separate this value into distinct capacity and energy benchmarks. The capacity benchmark should be established based upon the capital and fixed O&M costs of a new CT. *CalWEA/Beach, Ex. RPS-12, Ch. 1, at 6, and Beach, Tr. at 3083-3084.* As noted by Mr. Beach, the Commission has used the CT proxy to represent the value of capacity ever since

⁵ It would be too speculative at this point to determine the precise manner in which contract price data and cost data could be used jointly.

the 1980s. *See e.g.*, Decision No. (“D.”) 82-12-120, 10 CPUC 2d 553, 602 (noting that capacity payments were to be based on the cost of CTs), *citing* D.82-04-071. This proposal is also identical to the proposal of the Office of Ratepayer Advocates. *ORA/Smith, Ex. RPS-39*, at 2 and 5, n.9. The California Energy Commission has recently determined this capacity cost to be \$76 per kW-year or \$8.68 per MWh at a 100% load factor. *CalWEA/Beach Ex. RPS-12*, at 6, *citing* “*Comparative Cost of California Central Station Electricity Generation Technologies*” (CEC Staff Report, February 11, 2003), at D-3.⁶ The energy benchmark is then determined by subtracting the capacity benchmark from the all-in combined cycle cost. *Id.*

CalWEA’s proposed benchmark methodology should be adopted because it is flexible enough to allow consideration of both long-term contract prices and new-build cost data. It is also based upon transparent information sources and time-tested Commission methodology. It is integrated with both the least cost / best-fit process and the standard contract terms and conditions proposed by CalWEA. Finally, it will allow a fair and reasonable method of allocating contract costs to the utilities’ customers and to the PGC fund.

B. LEAST-COST/BEST-FIT

One of the more challenging aspects of RPS program implementation is developing the methodology required by § 399.14(a)(2)(B) for rank ordering and selection of the least cost and best fit renewable resources on a total cost basis. CalWEA has proposed, through the testimony of Mr. Beach, a coherent and, to the fullest extent possible, transparent process

⁶ As discussed below, CalWEA proposes that the market value of capacity determined in this proceeding be used to set the capacity payments for renewable suppliers under the standard contract terms and conditions. This is done by providing the full value of the CT to a renewable generator providing firm capacity (plus a potential bonus payment for exceeding the minimum performance requirements), and discounting the value of the CT for renewables providing unit-contingent or as-available capacity. Because the capacity payments to be received by the renewable generator will be the same capacity benchmark, the capacity payments and capacity benchmark will cancel out in determining the degree to which a given contract contains above-market prices for the purpose of allocating PGC funds. This allows the PGC determination to be based upon only the contractual energy prices and the relevant energy benchmarks.

for implementing the statutory requirement. CalWEA/Beach, Ex. 12, Ch. 2, at 1-7. The starting place for any methodology, naturally, is the definition of least cost / best fit.

1. Definition of Least-Cost / Best-Fit

As discussed in the testimony of Mr. Beach, the Commission should define least-cost / best-fit as follows:

Least-cost/best fit means the renewable resources that best meet the [utility's] expected future energy, capacity, ancillary service and local reliability needs, at the least cost on a net present value basis. To the extent that [a utility] does not need new resources to meet its system requirements in the near-term, and it does not otherwise plan to construct new facilities or procure additional power, then new renewable resources should be evaluated on the basis of least-cost alone. Least cost should be based on the combination of renewable and nonrenewable resources that satisfies the renewables procurement requirements of the RPS Program, meets the [utility's] electrical needs and minimizes total costs.

Id. at 1. This definition reflects the apparent desire of the Legislature to give preference to renewable resources that provide real value to utility customers, whether in terms of providing low cost energy and capacity, products that the utility would otherwise have to purchase from non-renewables, or a combination of both. This definition ensures, however, that renewables will not be shoe-horned in to fit utility needs when a combination of renewables and non-renewables can fit that need at a lower total cost. It also incorporates values (e.g., local reliability) beyond simply meeting RPS targets and capacity needs. *Id.* Finally, this definition reflects that the utilities are required to meet their RPS mandates even if they are not otherwise seeking products from non-renewable resources, and should do so on the basis of least-cost.

2. Renewable Product Solicitation

As discussed by CalWEA witness Mr. Beach, the process for selecting the least cost and best-fit renewable resources actually begins with the utilities' solicitations.

CalWEA/Beach, Ex. 12, Ch. 2, at 2. Because it will be impossible for the utilities to predict exactly how the market will respond to any given solicitation, the utilities should cast a wide net in seeking to meet their RPS energy and future capacity needs. In particular, the utilities should identify their resource needs and preferred products, but should not exclude any

renewable bidder from making a proposal, whether of the preferred product or another product.⁷ It may be that a renewable resource offering a non-preferred product can, when purchased at the same time as another resource (renewable or non-renewable), meet the utilities' needs on a lower cost / better fit basis than suppliers merely offering what the utility characterized in its bid packages as the desired product.

In addition, it would be prudent, although is not necessary, for the utilities to solicit renewable and non-renewable products simultaneously. *Id.* This would allow both for a more complete evaluation of least cost and best fit, as well as provide for a better chance of obtaining contract price information that can be used in setting market price benchmarks (as discussed above). Further, the utilities should solicit bids from suppliers that could come on line within three years in order to allow flexibility for new project development, consistent with the flexible compliance rules discussed below.

As discussed elsewhere herein, the utilities should seek three basic products from renewable suppliers: firm capacity, unit-contingent capacity and as-available capacity. Because the capacity payments for each product will be determined by the Commission based upon the market value of the relevant products, renewable developers should bid only energy prices. *Id.* This has the distinct advantage of enabling a simple “apples-to-apples” comparison among bidders and avoids the potential gaming experienced in the ill-fated BRPU proceeding. *See e.g.*, D.00-12-059, D.98-12-072 and D.98-12-074.

3. Bid Evaluation

There are two threshold principles that should govern the RPS bid evaluation process. First, § 399.14(a)(2)(B) wisely requires that renewable resource bids be evaluated on a total cost basis. This includes both the cost of the energy and capacity payments to be received by the given resource, and the indirect costs associated with any necessary transmission

⁷ In addition, the utilities should consider bids from QF projects whose contracts are expiring within 10 years of any solicitation. Those projects should be allowed to bid their output for their post-contract out-years for at least the balance of the contract term being offered to other suppliers commencing deliveries at an earlier date. For example, if a QF contract expires in 2010, and 20-year contracts are offered in a 2003 solicitation for deliveries beginning in 2005, the QF ought to be able to bid its output for the 15 years between 2010 through 2025. This policy will help to protect the utilities' renewables baseline by providing long-term revenue certainty that will allow major capital repairs and repowers that many of these aging projects require.

improvements and integrating the renewable resource into the utility portfolio. If renewable resource bids are not compared against each other on a total cost basis, the State cannot be sure that it is truly procuring the least cost and best-fit resources.

Second, as Mr. Beach states: “Each [utility] should evaluate bids using a consistent set of economic assumptions.” *CalWEA/Beach, Ex. 12, Ch. 2, at 3*. This (as discussed above) is essential in order to ensure that bids for different products are being evaluated fairly and that the outcome is truly the selection of least cost and best-fit resources.

With respect to capacity payments, it will be necessary to translate the dollars per kW-year or cents per kWh capacity payments into actual expected capacity payment amounts, based upon expected plant performance, so that different bids can be compared against each other. As explained by Mr. Beach, this should be done by using effective capacity values (i.e., anticipated capacity factors during peak demand periods) adopted by the Commission based upon the studies now being conducted under the auspices of the California Energy Commission. *Id.* Integration costs should also be assessed using the results of these same studies. *Id.*

As illustrated in the examples attached to Mr. Beach’s testimony, bids should be evaluated based upon their ability to meet both the utility’s RPS energy and ongoing capacity needs at the lowest cost. Those bids that meet the utilities’ energy and capacity needs at the lowest cost should be accepted. As Mr. Beach recognizes, it likely will be necessary to employ computer models to evaluate the relative costs and benefits of given resources. *Id.* In order to promote credibility, however, the utilities should be required to make as many of their modeling assumptions and techniques publicly available as is possible. As Mr. Beach states, “there should be a presumption of transparency; any exceptions should be justified by the utilities and approved by the Commission.” *Id.*

CalWEA’s proposed methodology has numerous benefits. As stated by Mr. Beach, by allowing all renewables to bid to meet the utilities’ needs (irrespective of the particular product the utility is seeking), and by combining renewable and non-renewable solicitations, the truly least cost and best fit solution becomes possible; the Commission can be less concerned about the utilities procuring expensive products from renewable generators that

may be ill-suited to provide them so as to deplete prematurely available PGC funds. *Id. at 4.* Second, CalWEA's integrated least cost / best-fit benchmark and standard contract terms proposals ensure that renewable bids are compared evenly and without subjective and arbitrary determinations of capacity value. *Id.* Third, CalWEA's approach clearly meets the requirements of the Public Utilities Code regarding least cost / best fit procurement. Fourth, CalWEA's proposal is objective and transparent, allowing the Commission and other parties to be confident in the results. Finally, by rewarding production during peak periods, CalWEA's proposed method will devalue bids for delivering during periods when overgeneration is more likely to occur. Beach, Tr. at 3058-3059.

4. Determination of Indirect Transmission Costs

As discussed above, the Commission is required, as part of the total cost bid comparison, to consider transmission upgrade costs that may be associated with new renewable suppliers. Before adopting a specific proposal, the Commission must recognize that, as part of the least-cost / best-fit process, determination of indirect transmission costs must also be pursuant to a transparent and fair process, and one that is timely so that the results may be incorporated into the bids of potential renewable suppliers.

As Mr. Beach explained, there would be a need to determine the actual transmission costs, as well as the cost responsibility, in advance of the bids so that bidders and utilities have adequate information on which to make and evaluate bids. *CalWEA/Beach, Ex. RPS-12, Ch. 2, at 4.* Failure to provide timely information could yield negative consequences in at least two ways: (i) if the bidders include their perception of the worst-case scenario and overestimate the transmission costs in their bids, the inflated bids (if accepted) will increase costs to ratepayers and put additional pressure on the limited PGC funds; and (ii) if the bidders underestimate the transmission costs in their bids, the winning bidder may not be able to develop its project. *Id. at 4-5.*

In determining the indirect transmission costs that will constitute bid adders, the Commission should not simply rely on the utilities to estimate transmission costs and to determine cost responsibility because the utilities' predictions may diverge both from legitimate estimates of renewable suppliers and the Commission's final determination of

network benefits under § 399.25. Instead, as proposed by CalWEA in its March 11, 2003 comments in R.01-10-024 and I.00-11-001, the Commission should hold expedited hearings (where necessary) to determine the likely costs and level of network benefits associated with new transmission projects to serve renewable resource growth. These same determinations should be employed in the RPS process for determining indirect transmission cost bid adders. While it is undeniable that the actual transmission upgrade costs and cost allocation will be determined through a process before the Federal Energy Regulatory Commission (“FERC”), this in no way precludes the Commission from reaching its own conclusions on costs and preferred cost-allocation for use in allocating costs to bids in the Commission’s own RPS program (or from advocating these positions before the FERC, as required by § 399.25(b)(3)). CalWEA’s proposal properly addresses these issues (and it is the only one addressing these issues). *Id.*

Where transmission costs and cost responsibility have been determined pursuant to the process set forth in I.01-11-001, the estimates should be used in the least-cost / best-fit process. For transmission costs without associated network benefits, the costs are the responsibility of the developers and will be included in the developers’ bids – these costs are not indirect costs. For those costs that do provide network benefits, an appropriate share of the costs should be divided among the bidders and unbid resources if the transmission upgrade is not fully loaded with bids on a per megawatt basis, as discussed below. *Id.* 5-6.

Where transmission costs and cost responsibility have not been determined, the utilities would estimate the transmission costs for each project and resource area using a pre-approved Commission methodology before the bidding. *Id.* at 6. The utilities should file proposed estimation methods with the Commission for approval in advance of any RPS solicitation. By requiring the use of either Commission-approved determinants, or determinants developed from Commission-approved methodology, CalWEA’s approach provides, to the fullest extent possible, bidders with information in advance of the bidding process and avoids the use of a “black box” in the bid evaluation process.

In both cases, where transmission cost responsibility has been formally determined and where it has not, the Commission should consider the extent, if at all, to which the costs

of transmission projects that result in significant network benefits should be added to bids. The Commission should guard against methods that would penalize renewable projects that require substantial transmission investments but that result in substantial improvements to the network. In some cases, a particular upgrade might produce benefits to the network far in excess of its cost. The Commission should avoid approaches that provide bidders with an incentive to support transmission plans that seem to minimize the upgrade costs associated with their projects, when a more expensive upgrade might create larger network benefits. Likewise, it makes sense to credit projects that relieve congestion.

C. FLEXIBLE COMPLIANCE, RECS, AND PENALTIES

1. The Commission Should Support Development by the Energy Commission of an Accounting System Based on Renewable Energy Credits

Under § 399.13(b) the Energy Commission is required to “design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, to ensure that renewable energy output is counted only once for the purpose of meeting the renewables portfolio standard of this state or any other state, and for verifying retail product claims in this state or any other state.” Even though the establishment of an accounting system is the responsibility of the Energy Commission, the Commission should, in this proceeding, make recommendations to the Energy Commission on the preferred accounting system. This is because the accounting system is inextricably linked to the compliance flexibility mechanisms and standard contract terms adopted by this Commission in this phase of the proceeding, and to many other aspects of the RPS program as it will evolve in the future.

For example, the Commission has ruled that, for purposes of this phase of the proceeding, parties are to assume that all environmental attributes of a particular resource will be transferred to the utility as part of the power purchase contract. Tr. at 2468-2469. It may be, however, that in the future, certain attributes will be unbundled from others and remain with the sellers. It is also possible that, although the trading of renewable attributes apart from energy has been determined to be beyond the scope of this phase of the proceeding, such unbundled trading may be allowed in the future as it is permitted in other

states. Tr. at 2467-2468. *See also, CalWEA/Rader, Ex. RPS-12, Ch. 3, at 2.* As such, to facilitate these kinds of RPS compliance and contract alternatives, adopting an accounting system that allows for such unbundling, whether or not it ultimately takes place, would be, all else being equal, the preferred outcome. As discussed below, this is one reason why CalWEA supports adoption of a REC-based accounting system.

CalWEA proposes the development of a REC-based accounting system, in which the generation and transfer of the renewable energy attributes associated with renewable power generation would be recorded in a single, electronic database covering the entire Western Electricity Coordinating Council (“WECC”) region.⁸ There are several reasons to do so.

First, as a result of the rulings in this phase of the proceeding that all renewable attributes are to be assumed to be transferred with the energy sold, and that there will be no trading of attributes separate from the underlying energy, a REC-based accounting system is equivalent to a MWh-based accounting system. *See* Roby Roberts, Tr. at 2538-2539. In other words, because all RECs are bundled with the underlying energy, an accounting system that tracks the amount of RECs is the same as a system that tracks the amount of energy on a MWh-basis. Nevertheless, the Commission should endorse a REC-based accounting system upfront so as to later permit REC trading and attribute unbundling if it so chooses. Simply stated, as CEERT witness Mr. Roberts explained, it would be inefficient to adopt a non-REC-based accounting system now, and to abandon it later in favor of a REC-based system that permits the trading of attributes. Roberts, Tr. at 2539-2540.

Second, such a system would fulfill the legislative requirement that the accounting system verify compliance with the RPS program and ensure that renewable energy is counted only once in this or any other state.⁹ § 399.13(b). During her cross-examination, CalWEA

⁸ The Energy Commission appears to be evaluating such a system. *See* Energy Commission, “*Customer Credit Renewable Resources Account, Report to the Governor and the Legislature*” (March 2003). This report describes how a REC system would function, and the benefits of such a system, and suggests that PGC funds previously allocated to the Customer Credit Program could be redirected to pay for the establishment of a REC accounting system, which would support REC trading. (For another description of how a REC system would work and its benefits, see CalWEA’s January 6, 2003, comments in this proceeding.)

⁹ A Western United States accounting system will be necessary regardless of the resolution of the eligibility of out-of-state renewable resources in the RPS program because renewable facilities

witness Nancy Rader explained why a REC system would help to prevent double counting beyond the West:

The point of having a single clearinghouse for attributes is to prevent the possibility that someone may have sold [a utility] the attributes under a contract, and also sold them to someone else under another contract. ...[B]y having a clearinghouse, all the parties could know that any generation in the West is going to have an attribute accounted for in that clearinghouse. ...So if somebody in Germany can pretty readily find out that the attributes are accounted for in this central clearinghouse, then it would be a fairly simple matter to check to see whether they have been sold; whereas if you have a contract path system, it is far more difficult. Tr. at 3128-3129.

Third, a REC-based accounting system would facilitate the compliance flexibility mechanisms proposed below by providing a simple and efficient means of tracking compliance deficits and surpluses. As discussed above, CalWEA's proposal provides a central clearinghouse for reporting and tracking of RECs (and therefore renewable energy). This accounting system allows the Commission to easily monitor the utilities compliance throughout the years and is far more efficient than a paper based, contract-path accounting system. *CalWEA/Rader, Ex. RPS-12, Ch. 3*, at 1¹⁰.

Lastly, a REC-based accounting system is likely to cost no more than a manual, audit-based contract-path tracking system. Roberts, Tr. at 2539. This fact is indicated by the adoption of REC systems in eight other states.¹¹

As the Commission is not addressing in this phase the issues of attribute unbundling, the Commission could simply require that the RECs (i.e., all renewable attributes associated with a kWh of renewable energy) from a particular facility be registered in the REC accounting system and transferred solely to the entity that purchases the associated power.

located in California could sell their attributes to an entity in another state. The Energy Commission has reserved \$1.3 million annually for five years to pay for the potential establishment a Western REC system, and presumably did so in consideration of the benefits of such a system and its cost relative to the methods that it is currently using for numerous purposes, including verifying renewable energy content labels. See Energy Commission, *Customer Credit Report* at 30.

¹⁰ See also, Energy Commission, *Customer Credit Report*, Appendix 1, at 16-17.

¹¹ See Energy Commission, *Customer Credit Report* at 24.

Upon any such transfer, the transferring entities (both the buyer and the seller) would notify the clearinghouse and the transfer will be recorded. The Commission should work with the Energy Commission to ensure that the REC system is designed to support such tracking.¹²

At some point, the Commission must decide whether all environmental attributes must be included in the RECs or whether some such attributes will remain with the renewable generators. A nearly identical issue is deciding what attributes comprise “renewable” attributes that are transferred with energy and what attributes are not renewable and remain with the seller. These are critical issues that should be resolved prior to the first bid solicitation, because both the utilities and the renewable sellers must know what attributes the utilities are obligated to acquire to meet the RPS requirements and what attributes the renewable sellers must sell. The latter information is essential for the renewable generators to properly evaluate their potential revenues from RPS (and other) sources and to develop a bid.

Ideally, but not necessarily, the Commission would also decide before the first bid solicitation whether, and under what circumstances, RECs may be purchased apart from the associated power and counted toward RPS compliance. If the Commission should make this determination, it does not need to “create” the REC trading market or to establish the rules for such markets; the market can be expected to develop privately (indeed, REC markets and brokers already exist).¹³ The Commission needs only to specify what characteristics the RECs must have in order to qualify for RPS compliance. This might include, for example, a requirement that the power that produced the RECs be sold to a California retail seller (so as to increase the likelihood that California consumers will receive the fixed-price benefits of the renewable power).

¹² The REC system used by NEPOOL (which is called a “GIS” system) is able to track energy deliveries and the associated RECs; i.e., RECs do not automatically become unbundled from the energy under a REC system. *See e.g.*, “Comments of APX Inc. on Out-of-State Eligibility Under Phase 1 of the RPS Proceeding.” CEC Docket No. 03-RPS-1078, March 28, 2003.

¹³ *See*, Energy Commission, *Customer Credit Report* at 23 (discussing Automated Power Exchange’s green tag market for California).

2. The Commission Should Adopt Reasonable Compliance Flexibility Mechanisms That Promote Least-Cost / Best-Fit Benefits

While not providing a specific utility compliance scheme, § 399.14(a)(2)(C) directs the Commission to adopt, by rule, “[f]lexible rules for compliance including, but not limited to, permitting electrical corporations to apply excess procurement in one year to subsequent years or inadequate procurement in one year to no more than the following three years.” As discussed in the prepared testimony of CalWEA witness Ms. Rader, CalWEA proposes that the Commission adopt four specific rules to implement the statutory requirements.

CalWEA/Rader Ex. RPS-12, Ch. 3, at 2-4.

Before addressing CalWEA’s specific proposals, it is important to consider that the underlying premise of CalWEA’s proposed compliance flexibility measures is the adoption of specific and substantial per-kWh penalties for any utility failure to meet their APTs after these flexibility measures are taken into account.¹⁴ Simply put, without the threat of meaningful non-compliance penalties, there is no point to adopting any flexibility measures. If the utility believes that deviations from RPS mandates will either go unpunished or that the threat of punishment is too remote to serve as legitimate deterrent of improper conduct, then flexible compliance rules are not needed (as the utility will perceive that it already has flexibility) and will only serve to broaden the perceived ability of the utility to avoid RPS compliance.

CalWEA’s four proposed flexibility mechanisms are as follows: (i) a three-month true-up period, (ii) a five percent “safe harbor” deficit allowance, (iii) unlimited credit banking, and (iv) deferred compliance to achieve least-cost / best-fit benefits. *Id.* at 2-3. Although the following discussion assumes the existence of a REC accounting system, the mechanisms could be employed under a manual accounting system as well.

a. Three-month true-up period

As Ms. Rader states, each utility should have three months after the end of a compliance year (i.e., until March 31 of the following year) to remedy any REC shortfalls that may exist at year’s end. *Id.* at 3 This flexibility mechanism reflects the fact that a utility

¹⁴ The APT would include the 1% annual increase requirement plus any decline that has occurred in the retail seller’s baseline, i.e., the APT is the “1% net increase” requirement.

may, in good faith, attempt and expect to comply with its APT but be out of strict compliance due to naturally occurring variances in annual renewable resource production or variations in load as a result of factors outside the utility's control (e.g., weather). A utility should be able to remedy the shortfall using eligible RECs of any vintage, including those generated during the true-up period, effectively borrowing from the following year. Rader, Tr. at 3131-3132.

b. Five percent "safe harbor" deficit banking

A retailer should also be able to fall below its APT by up to 5 percent without penalty and without explanation. This too reflects the fact that it is impossible to predict precisely how much renewable sellers will generate and how much retail customers will consume.¹⁵ This shortfall should have to be made up at the end of the following compliance year. However, the Commission should make clear that it will not tolerate repeated use of this provision.

c. Unlimited banking of unused credits

RECs should have no expiration date, and retailers should be able to bank unlimited quantities of RECs for future use. This is supported by many active parties to this proceeding. *See e.g., CalWEA/Rader, Ex. RPS-12, Ch. 3, at 3; Edison, Ex. RPS-5, at 3; and TURN, Ex. RPS-25, at 33.* Unlimited banking will encourage early compliance and provide retailers with an important compliance management tool. A bankload of renewable credits, for example, will enable a utility to mitigate any possible claim that renewable sellers may hold the utility "over a barrel" and have undue bargaining power to force the utilities to buy renewable supplies under unreasonable terms. Such a bankload also will minimize the need to impose penalties on developers that fail to perform on contract delivery expectations, which would only serve to drive up bid prices.

As part of allowing unlimited banking, it is essential for the Commission to clarify that the 20 percent renewables mandate is to be maintained indefinitely. Otherwise, unlimited banking could lead to an unstable ("boom and bust") renewable energy market if extreme over-compliance occurred in early years and there were no market in later years.

¹⁵ This assumes that the APT will reflect actual retail consumption for the applicable compliance year.

Thus, if the Commission fails to clarify that the utilities will be required to maintain a 20% portion of their portfolio from renewable resources, CalWEA will not support unlimited forward banking.

d. Deferred compliance to achieve least-cost / best-fit benefits

As required by § 399.14(a)(2)(C), utilities should be able to defer compliance in order to accommodate the lumpiness of resource additions and to undertake long-term advance planning. Consistent with the statute, a utility should be able to defer compliance for up to three years beyond the compliance year. Deferral, however, should be limited to that portion (or all) of the APT that the utility specifically justifies and the Commission authorizes. Otherwise, the three-year compliance deferral will simply be a blank check for the utilities to delay RPS procurement. Placing reasonable conditions on compliance deferrals is warranted to ensure that the delays in compliance are the result of careful planning rather than a desire merely to postpone compliance.

As Ms. Rader explains, deferrals should be approved where: (i) the results of the least-cost/best-fit evaluation of bids demonstrate that substantial benefits can be captured through a deferral; and (ii) contracts are being signed for future deliveries that will bring the utility into compliance as planned. *CalWEA/Rader Ex. RPS-12, Ch.3*, at 3-4. In addition, if the utility requesting the deferral is the transmission owner for the project that will provide the deferred deliveries, the utility should demonstrate steady progress toward completing any new transmission capacity that is required.¹⁶ As discussed above, the utilities should solicit bids for deliveries commencing up to 3 years into the future so that they possess all of the information they need to evaluate longer-term options. As stated by Ms. Rader, this will allow the utility to evaluate the effect of any limited short-term needs and defer compliance if that will reduce costs and increase benefits. Tr. at 3123.

¹⁶ If the utility is not the transmission owner, it should only sign the contract if it is likely that the necessary transmission capacity will materialize on time. If there was a reasonable expectation of that, and the transmission owner acted unreasonably such that the utility falls out of compliance and is unable to timely remedy the situation, then the contracting utility should be able to appeal its noncompliance status to the Commission.

While § 399.14(a)(2)(C) does not expressly require the Commission to limit the utilities' ability to defer inadequate procurement in one year to the following three years, the Commission should nevertheless adopt such limits. As discussed above, good public policy reasons support the Commission's adoption of the limits proposed by CalWEA. Further, there is nothing in the statute that prevents the Commission from limiting or conditioning the ability of utilities to apply inadequate procurement in one year to the following three years; the legislation merely established a maximum of three years over which such "deficit banking" may occur.

3. The Commission Should Adopt Significant, Automatic Noncompliance Penalties

As discussed above, an essential element of the RPS program's flexibility compliance mechanisms should be the adoption of specific and substantial penalties for noncompliance. § 399.14(d) specifically addresses penalties for utility noncompliance, stating that if a utility fails to comply with a Commission order adopting a renewable procurement plan, then the Commission must exercise its enforcement authority pursuant to Section 2113 to require compliance. Section 2113 provides:

Every [utility], corporation, or person which fails to comply with any part of any order, decision, rule, regulation, direction, demand, or requirement of the [C]ommission or any commissioner is in contempt of the [C]ommission, and is punishable by the [C]ommission for contempt in the same manner and to the same extent as contempt is punished by courts of record. The remedy prescribed in this section does not bar or affect any other remedy prescribed in this part, but is cumulative and in addition thereto.

That the Legislature did not establish particular penalties does not mean that it rejected such penalties (in that case, it would have specifically rejected them). Rather, it left the decision to the Commission.

Establishing specific administrative penalties at the outset of the RPS program that are significant, transparent and automatic will provide a number of essential benefits that will help to ensure the success of the RPS Program: (i) it will make the RPS Program self-enforcing, providing the utilities a strong self-interest to comply fully with the program and creating a disincentive for the utilities to test the Commission for ways not to comply with the RPS program; (ii) it will reduce the Commission's cost of enforcement; and (iii) it will

provide renewable energy developers with confidence that a market will exist for the product of their efforts, which will in turn increase competition and lower RPS compliance costs. This kind of penalty scheme was adopted as part of the RPS program in Texas, which has been extremely successful. *CEERT/Roberts, Ex. RPS-1*, at I-15.

a. Imposition of Penalty

As Ms. Rader states, any compliance deficiencies in excess of 5 percent of the APT, adjusted for any approved deferrals, remaining on April 1 of the following year should be subject to a swift, automatic noncompliance penalty. *CalWEA/Rader, Ex. RPS-12, Ch. 3*, at 4. The penalty should not be recoverable from ratepayers or passed on to renewable developers that might, in the utility's view, have contributed to their shortfall. Passing penalties onto developers could substantially raise bid prices. Moreover, there is no need to pass penalties on to developers since retailers have other tools at their disposal to ensure that they can meet their compliance targets, such as project development milestone requirements, and the ability to manage compliance by making use of the compliance flexibility mechanisms. Finally, the payment of a noncompliance penalty does not serve to excuse the utility from compliance; the shortfall should be added to the utility's APT for the following year.

b. Amount of Penalty

As Ms. Rader testifies, penalties for compliance deficiencies, after taking flexibility measures into account, should provide a substantial incentive for all retail sellers to comply with their ongoing RPS program requirements. *Id.* at 5. The penalty should significantly exceed the expected cost of compliance, following the successful example of Texas, where noncompliance penalties equal the lesser of (i) fifty dollars per megawatt-hour, or (ii) in the event that the Commission approves tradable RECs, 200% of the average market value of eligible RECs for the relevant compliance period. *CEERT/Roberts, Ex. RPS-1*, at I-15. The Commission should make clear that retail sellers are responsible for conducting sufficient advance planning and that even failure of a contract party to deliver or failure of the spot or short-term market to supply a retail seller with RECs would not constitute an event excusing compliance with the RPS Program requirements.

c. Disposition of Penalty Revenues

Penalty revenues should be deposited in the CEC's PGC account for New Renewables/Supplemental Energy Payments. *CalWEA/Rader, Ex. RPS-12, Ch. 3, at 5.*

d. Additional Penalties should be Permitted

The Commission should retain the authority to levy additional penalties on top of the automatic administrative penalties for repeated or flagrant utility violations of the RPS Program requirements. In addition, if the Commission finds that a utility has procured renewables in violation of the Commission's least-cost / best-fit RPS rules, the associated energy should not be credited toward the utility's baseline or APT in order to provide an adequate deterrent against such violations.

D. STANDARD CONTRACT TERMS AND CONDITIONS

§ 399.14(a)(2)(D) requires the Commission to adopt, by June 30, 2003 "[s]tandard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators." While there was no cross-examination on these topics during the recent hearings, parties did provide, through supplements to their testimony, proposals to the Commission on standard contract terms and conditions. As set forth in CalWEA's supplement to its testimony, the Commission should adopt, in this phase of the proceeding, standard contracts (but not, as discussed below, standard offers) for use in the RPS auctions. In particular, the Commission should adopt standard contracts for three particular renewable products: firm capacity, unit-contingent capacity and as-available capacity. CalWEA has proposed forms of such contracts (using EEI documentation), which are attached to its supplement on standard contract terms.

1. The Legislature Intended for the Commission to Standardize Generally the Terms and Conditions that the Utilities Will Use in Contracting With Renewable Resources

Without question, it was not the Legislature's intent that the Commission could satisfy its obligations under § 339.14(a)(2) by adopting only a few standard contract terms and conditions. To the contrary, in the context of the entirety of the legislation relating to the

RPS Program, it is clear that the Legislature intended that the Commission standardize generally the terms and conditions that the utilities will use in contracting with renewable resources and adopt these standard terms and conditions by June 30, 2003.

The fundamental premise of the RPS legislation is that the utilities should increase their purchases from renewable resources. In order to ensure that the utilities actually do increase their purchases from renewable generators, the legislature imposed specific requirements on the utilities and the Commission to facilitate such increased purchases, including the requirement that the Commission adopt standard contract terms and conditions for use by the utilities and renewable suppliers. If the Commission were to adopt only two, or even only a few, standard contract terms and conditions, it would not, in any meaningful sense, be facilitating increased purchases from renewable resources and effectuating the Legislature's intent. *CalWEA, Ex RPS-12, Supp. at 2-3*

By requiring that the Commission adopt standard contract terms and conditions, the Legislature understood that such Commission oversight and standardization will facilitate the development of renewable resources and full achievement of the 20% RPS target. Commission oversight and standardization of the contracts terms and conditions will ensure, among other things, that the utilities do not (i) impose unreasonable terms and conditions upon renewable developers (which prevent project-financing or raise bid prices unnecessarily), (ii) arbitrarily favor one type of renewable resource over another, or (iii) favor one developer over another. Standard terms and conditions are necessary to level what would otherwise be an extremely non-level playing field between the utilities and renewable suppliers. *Id. at 3.*

2. Other Considerations

Standardizing as much as possible the terms and conditions to be used in the RPS Program is also necessary to ensure that, as part of the required least-cost, best-fit analysis, different renewable proposals are able to be compared against each other in a meaningful manner. *CalWEA, Ex. RPS-12, Supp. at 5.* If renewable suppliers bid contracts with a wide variety of terms relating to such topics as performance requirements, termination rights and remedies for default, the comparisons among the offers will be, of necessity, extremely

difficult and subjective. In order to ensure maximum credibility for the RPS Program, the Commission should strive to make bid selection as objective as possible.

In addition, such standardization is also necessary to ensure meaningful comparisons between renewable proposals (and perhaps non-renewable proposals) and the market price referents to be developed for allocating PGC funds. Such market price referents are, in accordance with § 399.15(c)(3), to be differentiated based upon various products. The applicable contract terms and conditions are what define the various products. *Id.* at 5-6.

This does not mean that the Commission must standardize pricing terms, which are to be bid by the renewable developers in the utility solicitation. The Commission also cannot specify the delivery point or contract quantity, which are project-specific. In fact, further towards the legislature's intent, it is common parlance among industry participants to refer to the "terms and conditions" or "Ts and Cs" as all of the terms other than project-specific terms like delivery point, quantity and pricing. *Id.* at 6.

This also does not mean that the utilities should be prohibited from negotiating with bidders. CalWEA's proposal recognizes that it is impossible to develop contract terms and conditions that will apply well to every possible renewable project. *Id.* In fact, it is essential that the renewable developers and utilities have the ability to tailor the adopted standard contract terms and conditions to the specific attributes of a given renewable supplier. In essence, CalWEA's proposal is that the standard contract terms and conditions adopted by the Commission be treated as presumptively reasonable; and if a renewable developer can accept them, the utility will not require changes or seek to impose other terms and conditions upon the supplier. *Id.* Having the standard terms and conditions will allow the Commission to compare efficiently negotiated terms, assess appropriate values associated with such negotiated terms in connection with both the least-cost, best-fit analysis and adopted price referents, and determine the reasonableness of the contract in comparison to other proposals.

3. Consistency of Contract Terms Among the Utilities

CalWEA also proposes that, unless there is an articulated reason justifying different contract terms among the utilities, the utilities should have the same standard contractual terms. *CalWEA Ex. RPS-12, Supp.* at 8. While § 399.14(a)(2) does not explicitly require that

the standard contract terms and conditions be the same for all utilities, there is substantial value in promoting consistency among the terms and conditions that will be applicable to renewable suppliers in the different utility service territories. *Id.* Among other things, renewable suppliers will not be benefited or disadvantaged simply because of their project location, and contract terms and conditions will not be a basis for renewable suppliers to seek or avoid one utility purchaser over another.

The Commission should naturally recognize that each of the utilities has different needs from the others, but the differences are in the amounts and kinds of the products that the particular utility's needs. The same terms and conditions should therefore be applied to similar products, and the Commission should adopt a general rule against differentiating the standard terms and conditions among the utility unless there is a demonstrated legitimate reason. *Id.*

4. Standardized Solicitation Process

As CalWEA proposes, the Commission also should standardize certain elements of the utilities' solicitation process. *Id.* at 8. Although not every aspect of the solicitation process needs to be identical for all utilities, certain rules should be standardized. Some examples were already discussed in connection with the least-cost / best-fit issues. For example, the Commission should require the utilities to solicit bids from suppliers that could come on line within three years in order to allow flexibility for new product development to match the flexible compliance rules as discussed above. The utilities should also permit all renewable suppliers to bid, even if the bid is not for the stated product being sought.

Generally speaking, the Commission should prevent the utilities from arbitrarily imposing rules that unduly limit bidders' flexibility and the potential efficiency of the RPS program, such as rules that prevents a bidder from bidding in more than one solicitation. Similarly, rules regarding the treatment of incremental output from projects covered under existing contracts, including projects that are repowered or expanded, should be adopted. *Id.* In particular the Commission should direct the utilities to offer existing renewable QF owners standard QF amendments that extend the term of the existing power purchase agreements and encourage maximizing energy deliveries. This is also supported by TURN. *TURN, Ex. RPS-25, Supp.* at 6.

5. Standard Products and Performance Requirements

The Commission is also mandated under §399.14(a)(2)(D) to adopt standard performance requirements for renewable generators. Given that performance requirements are inextricably linked to the product being offered, it is essential for the Commission to adopt standard product definitions, accompanied with performance requirements, based upon actual contract provisions, as CalWEA has included in the supplement to its testimony. *CalWEA, Ex. RPS-12, Supp.* at 9-10.

CalWEA's proposed performance requirements contain incentives for bidders to provide products with higher reliability. *Id.* For example, the generator providing the Firm Capacity product receives 100% of the capacity payment upon meeting its performance requirement, and is eligible for a bonus payment for achieving capacity factors during peak hours above the performance requirement. Unit-contingent bidders will have a less stringent performance requirement and is not eligible for bonus capacity payments but is designed to provide to the utilities the benefits of allowing the Unit-contingent bidder to take the full risk of rising fuel costs. As-Available bidders, with a lower performance requirement, will only receive capacity payments to the extent that they actually operate, but may receive higher capacity payments if they perform consistently during peak-hours of peak-months.

These contract terms and conditions contain strong incentives for projects to deliver products that are most valuable to the utilities, consistent with the technology and location of the project. At the same time, energy payments to all projects would be time-differentiated, to reflect the changing value of the energy by time period. *Id.*

6. Other Specific Issues

CalWEA's proposal on standard contract terms and conditions also addresses several specific critical issues. These include credit support, scheduling, and confidentiality. *Id.* at 10-12. CalWEA's proposals and these topics are discussed below.

a. Credit Support

Under CalWEA's proposal, assuming that the utilities have an investment-grade credit rating, the Commission should not require additional credit support for either the utilities or the developers, aside from a reasonable and refundable "earnest-money" deposit to be paid by a winning renewable bidder upon contract execution. *Id.* at 11. First,

CalWEA's standard contract terms and conditions already provide the necessary protections for the utilities. *Id.* As CalWEA explained in its supplement to its direct testimony, (i) the earnest money deposit will weed out weak or non-serious bidders; (ii) project development milestones, such as those included in CalWEA's proposed contract, will further ensure that utilities are not saddled with non-viable projects; and (iii) once the project achieves commercial operation (and the earnest money deposit is refunded), the developer has sufficient wherewithal and incentive to deliver product output over the contract term. *Id.* at 11.

Second, the large capital investment inherent in developing a project, combined with contract terms that prohibit termination by the QF for economic reasons, will adequately assure performance during the contract term. As set forth in CalWEA's supplement to its testimony, it is much more difficult to develop, finance and construct a project in California than it is to operate one. *Id.* at 11. It is important to keep in mind that thousands of MW of independent generators, including renewables, have been developed, financed, constructed and operated in California under the standard offer contracts, without any credit support mechanism aside from an earnest money deposit. Imposing requirements beyond the earnest money deposit requirement would create unnecessary barriers and deter small developers. *Id.*

Lastly, if the utilities decide to take on RPS procurement before they are considered investment grade, it may be possible that some credit support will be required in order to allow financing at a reasonable cost.

b. Scheduling

As stated in CalWEA's supplement to its testimony, one feature of the California energy market that imposes a particular challenge in virtually all electricity contracts is that the power scheduled to be delivered and received through the California ISO does not always (and in fact often does not) match actual generation or consumption by the parties. *Id.* The differences, referred to as imbalances or deviations, are made up by the ISO in real-time. Financial responsibility for the additional power supplied by the ISO, or financial benefits for the excess power disposed of by the ISO, goes to the SC for the party whose actual generation or load failed to match the schedule. The ISO addresses imbalances over an entire

SC's portfolio of resources, although each individual SC is free to address imbalances among its customers on an individual basis.

Given that the utilities are purchasing a unique product that is not reflected in the ISO imbalance energy market, CalWEA proposes that the simplest and most straightforward way to handle this issue is to have the utilities serve as the SC for the renewable resource. *Id.* at 12 In this way, the utilities simply purchase all of the output of the resource (which could be capped at a pre-defined maximum level) and all associated renewable attributes, and spread any imbalance costs and benefits over their entire portfolios, as is done with current standard offer qualifying facilities. *Id.*

The Commission may not want to require that the utility to act as the SC for all of its renewable resources, but it should still require the utility to purchase all of the metered output from the generator, whether or not it was scheduled correctly with the ISO to ensure that the utilities receive all of the environmental attributes associated with the output of the renewable facility and that none of the attributes are lost in the ISO imbalance market. While not as simple as having the utility serve as the SC, this can be accomplished fairly easily in actual practice, through the two-step process proposed by CalWEA.¹⁷

¹⁷ CalWEA's proposal is as follows: in the first step, the utilities would assume that actual generation matched scheduled generation and pay the generator accordingly. When actual meter data subsequently becomes available, the utilities will proceed to the second step, a financial reconciliation, as follows. If the resource was under-scheduled, the utilities would pay to the generator the difference, if positive, between what would have been due at the applicable contract price and the amount that the generator (or its SC) received from the ISO for the excess generation. If the resource was over-scheduled, the generator would refund to the utility the difference, if positive, between what actually was paid by the utility at the contract price and the amount that the generator paid to the ISO for the provision of imbalance energy. In this way, the utility pays no more for the ISO energy than it would otherwise have paid in the imbalance market, and its liability for imbalance energy is capped at the original contract price. (In the under-scheduling scenario, the generator has the potential to earn more than the contract price if the ISO imbalance price was higher than the contract price at the time of generation. In the over-scheduling scenario, however, the generator would take on the corollary risk that it will have to buy expensive ISO imbalance energy to substitute for its own under-scheduled generation.) This approach, although not the only possible approach, fairly balances the potential risks and benefits associated with scheduling deviations while ensuring maximum utilization of renewable attributes. *Id.* at 12-13.

c. *Confidentiality*

One of the more challenging aspects of the RPS program, and current utility procurement in general, is determining how much contract information should be kept confidential. In order to ensure that the RPS program has maximum fairness, credibility and verifiability, confidentiality protections with respect to contract terms and conditions should be kept to a minimum. With the development of standard terms and conditions, there should be less need for confidentiality. The Commission should only allow the contract price and those terms that can be used to identify a given renewable project owner (e.g., its name, address, delivery point) be kept confidential. All other terms and conditions, including any negotiated terms and summary pricing (without attribution to a particular project), should be open for public review. Providing transparency and credibility in the renewable bidding process is essential to the success of the RPS program.

III. CONCLUSION

CalWEA urges the Commission to consider and adopt the proposals as discussed above.

Respectfully submitted,

Joseph M. Karp
Enoch H. Chang
White & Case LLP

Attorneys for the California Wind Energy
Association

April 28, 2003

APPENDIX 1

Table 1: Key Parameters for the Combined-Cycle Benchmark¹⁸

Parameter	Northern California (PG&E)	Southern California (Edison and SDG&E)
Long-term Gas Commodity Price	PG&E City-Gate	Topock
Gas Transportation	PG&E Schedule G-EG, plus the G-SUR surcharge	SoCalGas GT-F5, plus the G-MSUR surcharge
Gas Hedging Costs	\$0.50 per MMBtu	\$0.50 per MMBtu
Heat Rate	7,400 Btu / kWh	7,400 Btu / kWh
Variable O&M	\$4 per MWh	\$4 per MWh
NOx Emissions	0.05 lb/MWh	0.05 lb/MWh
NOx Costs	\$2 per lb.	\$4 per lb.
“Spark spread”	\$16 per MWh	\$16 per MWh
GMM Line Losses	3%	3%

¹⁸ *CalWEA/Beach Ex. RPS-12, Ch. 1, at 3.*

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the

**OPENING BRIEF OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON
THE IMPLEMENTATION OF THE CALIFORNIA RENEWABLES PORTFOLIO
STANDARD PROGRAM**

on all known parties to R.01-10-024 named in the official service list by electronic mail for all parties providing an email address, and by mailing a properly addressed copy by first-class mail with postage prepaid to each of the parties not providing an email address.

Executed on April 28, 2003, at San Francisco, California.

Parashita Marschall