Decision 04-07-029 July 8, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	Rulemaking 04-04-026 (Filed April 22, 2004)

OPINION ADOPTING CRITERIA FOR THE SELECTION LEAST-COST AND BEST-FIT RENEWABLE RESOURCES

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OPINION ADOPTING CRITERIA FOR THE SELECTION OF LEAST-COST AND BEST-FIT RENEWABLE RESOURCES

I. Summary

This decision addresses the requirement in Pub. Util. Code § 399.14(a)(2)(b), which provides that the Commission must adopt a process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources on a total cost basis to comply with the California Renewables Portfolio Standard (RPS) Program.[1] Today's order adopts least-cost, best-fit evaluation criteria for use in the 2004 RPS solicitation and directs the utilities to issue revised Requests for Offers (RFOs) for eligible renewable resources consistent with this decision and their approved renewable procurement plans. Since this is the initial RPS solicitation in a multi-year program of renewable energy development, we will revisit aspects of the adopted criteria as we gain more experience with the program, and as the renewable generation industry continues to evolve.

II. Background

On June 19, 2003, the Commission issued Decision (D.) 03-06-071, an Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program. The objective of the RPS program is to attain a target of 20 percent renewable energy for the State of California. To reach this goal, the legislation requires an increase in procurement of renewable energy of at least 1 percent per year.

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[1] *See*, Pub. Util. Code §§ 399.11 through 399.16.

The legislation also requires the Commission to adopt criteria for the rank ordering and selection of least-cost, best-fit renewable generation resources. D.03-06-071 developed the majority of the components of this evaluation, and identified two components for further study. Those two components are establishing capacity values for intermittent technologies and developing bid adders to reflect the cost of transmission needed to connect new renewable generation to the grid.

The task of developing any necessary bid adders was assigned to the Commission's Transmission Investigation (I.) 00-11-001, and an interim opinion on these issues was approved at our June 8, 2004 Commission Meeting.[2]

On the issue of capacity values for intermittent technologies, we found that the RPS program should utilize either the standard approach employed for Qualifying Facility (QF) resources, or the more refined analysis contained in the report "California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis" (Integration Study) prepared by the California Wind Energy Collaborative under the auspices of the CEC's Public Interest Energy Research Program, should the results become available in time.

Subsequently, on April 22, 2004, we issued the instant rulemaking to allow for the closure of the prior procurement docket and to address the remaining issues related to the implementation of the RPS. At that time, we identified four tasks that must be completed to enable the first round of RPS solicitations to occur. With the adoption of D.04-06-013, approving a methodology for considering transmission costs, D.04-06-014, adopting Standard Contract Terms

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[2] *See* D.04-06-013.

and Conditions and D.04-06-015, adopting the Market Price Referent methodology, three of those four tasks have been accomplished. This decision addresses the fourth task: resolving the remaining issues related to the rank ordering and selection of least-cost, best-fit renewable generation resources.

On May 20, 2004 the assigned ALJ issued a ruling establishing a schedule for the development of criteria for the rank ordering and selection of least-cost and best-fit renewable resources. A CPUC-CEC Collaborative workshop on least-cost, best-fit issues was held on May 24th and 25th, 2004. Following the workshop, parties agreed upon a common outline for addressing the issues in opening and reply briefs. The common briefing outline was distributed to the service list in this proceeding by ALJ ruling on May 27, 2004.

On June 4, 2004, nine parties filed opening briefs: the California Wind Energy Association (CalWEA), the Center for Energy Efficiency and Renewable Technologies (CEERT), the Green Power Institute (GPI), the Independent Energy Producers Association (IEP), the Commission's Office of Ratepayer Advocates (ORA), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and The Utility Reform Network (TURN). Reply briefs were filed on June 10, 2004.

III. Least-Cost and Best-Fit Evaluation Criteria

In the sections below we discuss contested issues raised by the parties regarding the least-cost and best-fit bid ranking and selection methodology.

1. Sequencing of RFOs

Several parties raise as a preliminary issue the degree to which the Commission should dictate the schedule for issuance of RFOs in the future. PG&E, SCE, SDG&E, ORA and GPI recommend that the utilities be granted the discretion to determine the best time for issuing RPS solicitations in years 2005 and beyond. The utilities note that the flexible compliance rules and associated penalties adopted in D.03-06-071 will effectively ensure compliance with RPS procurement goals in each procurement year, eliminating the need for the Commission to dictate specific solicitation dates. The utilities also argue that they are in a better position to determine when the most optimal and cost-effective procurement can occur in any given procurement year, including whether or not to issue a solicitation while another utility's solicitation is pending, suggesting that determining the optimal time for RPS solicitations in the future will require a level of market monitoring and administrative burden the Commission would not want to take on.

In addition, SDG&E and GPI point out that even if the Commission were to direct that RPS solicitations be issued simultaneously, or be deliberately sequenced to avoid overlaps, they would quickly get out of sync during the evaluation and approval process because the time needed to perform preliminary and second rankings and negotiate contracts will depend on the number of bids received and the number of bidders that are short-listed, and these factors will be different for each utility, resulting in either: (1) the MPRs being disclosed at different times whether the RFOs are issued simultaneously or sequentially, or (2) all three utilities being forced to follow the schedule of the slowest of the three.

CalWEA notes that if simultaneous solicitations are held, members of the utilities' procurement review groups may have access to confidential bid information from more than one utility solicitation. CalWEA expresses concern that, in this situation, PRG members might, in evaluating the bids, disfavor and discourage a utility from accepting a legitimate bid out of concern that the bidder is not bidding the lowest price possible.

TURN does not oppose allowing the utilities to issue concurrent solicitations in future years, so long as minimum standards of conduct are adopted for bidders.

Our immediate goal is to ensure that the utilities are able to issue the first round of RFOs for renewable generation in July 2004, consistent with the intent of this rulemaking and decisions D.04-06-014 and D.04-06-015. In D.04-06-014, we adopted a window from June 30, 2004 to July 15, 2004 during which utilities must issue RFOs consistent with their approved procurement plans (D.04-06-015, Ordering Paragraph 6). This decision adjusts that window slightly, to allow the utilities to revise their RFOs consistent with the directions herein. Thus, for the 2004 renewable solicitation, we have already decided that the RFOs be issued concurrently.

We find that it is premature to decide when the utilities should issue RFOs for 2005 and beyond. As a general principle, we agree that the utilities should be given substantial flexibility in the timing of future solicitations. However, given the current MPR calculation methodology, we are somewhat constrained by the legislative requirements that the MPR established by the Commission does not influence the bids submitted and that the bids submitted do not influence the calculation of the MPR. Since the MPR is a statewide number, if one utility's solicitation precedes another, and the MPR is released in response to that solicitation, the MPR may establish an effective bid floor. In Section 7 below, we indicate our intent to pursue refinements to the MPR calculation method for the next round of solicitations, including a time-of-delivery-based methodology that may, in addition to offering greater precision, allow multiple MPR calculations to occur during a calendar year without violating the statutory requirement that the Commission maintain the confidentiality of the MPR process.

We also find premature SDG&E's and TURN's proposals regarding timing of the 2005 renewable procurement plan filings. We intend to coordinate future renewable procurement plan filings with the Commission's schedule for overall procurement plan review.

2. Bidding Requirements

A second preliminary issue raised by the parties is the question of whether bidders should be permitted to submit bids for the same project in more than one pending utility solicitation. Although initially concerned that multiple bids could potentially pit utilities against one another in negotiating for the same project, resulting in inflated prices, the utilities agree to allow multiple bids on the condition that bidders be required to withdraw duplicate bids at the time that they are notified that they are "short-listed." Absent that withdrawal, the utilities argue that bids should be binding. The utilities also request that the Commission require bidders to indicate as part of their bid package whether they have or intend to bid to more than one entity. TURN agrees. SCE goes a step further and argues that utilities should be free to impose reasonable penalties, possibly including liquidated damages, on bidders who withdraw their bids after beginning negotiations.

The remaining parties (CalWEA, CEERT, GPI, IEP and ORA) agree that multiple bids should be permitted, regardless of whether the RFOs are issued simultaneously or sequentially, noting that proposals to limit the bidders' opportunity to participate in more than one RFO are anti-competitive, and could result in higher prices. These parties maintain that it is entirely possible, and proper, for a bidder to bid in more than one solicitation or bid a higher price in one solicitation than in another, explaining that the higher bid may result from factors such as the potential for transmission constraints and line losses that could increase the bidders costs, or from different perceptions of risk.

In its comments on the Draft Decision, CalWEA suggests that utilities should be allowed to request exclusive negotiating rights. This alternative would allow utilities to discontinue negotiations with bidders who refuse to withdraw competing bids, but would also allow them to continue negotiations with bidders for projects that they find particularly attractive.

For the 2004 RPS solicitation, the process we adopt is as follows. Bidders are permitted to submit bids into multiple solicitations. Bidders may bid whatever price they deem appropriate. After each utility notifies a bidder that it has been short-listed, the utility has the right to request that the bidder grant the utility exclusive negotiating rights for that project within a period no shorter than five days after the request.

If the bidder refuses to grant exclusive negotiating rights, the utility is not required to continue negotiations with that bidder. After the Commission has been notified that the last utility's short list is complete, the Commission's Energy Division will release the MPR. This approach provides a reasonable balance between bidder interests in submitting multiple bids and utility interests in having binding bids before proceeding to negotiations.

This approach also eliminates the need to require bidders to identify whether or not they have submitted multiple bids. As the utility will not be negotiating with bidders prior to establishment of the short-list, they have no need to know whether or not a bidder has offered the same project in another utility's solicitation. For the same reason, we reject TURN's recommendation that we amend the PRG confidentiality rules to allow PRG staff members to disclose to other utilities information regarding whether a particular project has been offered in another utilities' solicitation (without pricing data). Like GPI and CalWEA, we prefer the situation in which neither the fact nor the possibility that a project is bid into multiple solicitations enters into a utility's process of developing its short list. Therefore, we require that all bids be treated as potentially multiple until negotiations with a given bidder reach the stage at which parties formally agree to exclusive bidding rights.

3. RPS Solicitation – Contract Approval Schedule

The parties argued that the timing of contract approval will depend on a number of variables related to the complexity of the bids, requirements on the transmission system, negotiations, PRG review and other factors. All of these variables make it difficult to estimate with any degree of precision the length of time that will lapse between the issuance of an RFO and the filing of advice letters.

Given the fluid nature of the solicitation and contract approval process, we agree with the parties that it is unrealistic for the Commission to hold the utilities to a rigid solicitation schedule. Consequently, the Commission does not assign dates to the milestones listed in Table 1 "RPS Solicitation – Contract Approval Milestones" below. While there are no dates, the Commission strongly encourages the utilities to strive to have their RPS contracts approved by December 2004.

Table 1 - RPS Solicitation – Contract Approval Milestones

#	Milestone	Milestone Description
1	Utility issues RFO	July 9, 2004 to July 15, 2004 solicitation window
2	Respondents file notice of	

	intent to bid	
3	Deadline for respondents to submit bids	
4	Utility notifies CPUC when bidding has closed	Notify Commission via letter to Executive Director
5	Utility evaluate bids to develop short lists	PRG meetings, not including Commission staff, are held to review bid results
6	Utility notifies Commission when the initial short list is complete	Notify Commission via letter to Executive Director
7	MPR is calculated by Commission and is transmitted to parties	Release one MPR for 2004 – CPUC calculates and discloses MPR when all applicable IOUs have notified CPUC that their short-lists are ready for release
8	Utility issues short-listed bids to CPUC and PRG	Bidders have five days to withdraw all conflicting bids. Otherwise bid is binding
9	PRG/CPUC review utility short list	
10	Utilities and bidders negotiate and execute contracts	
11	Utility submits contract advice letters for CPUC approval	It may be appropriate for the utilities to file several groups of contracts in trenches as final agreements are reached. Contracts that do not require SEP funds should be submitted separately for expeditious treatment.
12	CEC evaluates proposed contracts for SEP availability and the need for caps	
13	30 days after receiving	PGC Funding Confirmations consist of

	proposed contracts, CEC releases PGC Funding Confirmations to CPUC, IOU, and individual bidders and will identify any caps imposed	letters from Renewables Committee to (1) CPUC, who sees all bidders' proposed awards, (2) IOUs, who see proposed awards from bidders in their solicitation, and (3) individual bidders, who only see their own proposed awards. Awards are contingent upon the receipt of necessary environmental permits
14	Utility and bidders restructure payment terms based on the amount of the SEP award, if desired[3]	Generators and utilities may re-structure IOU payment streams in their contract based on availability of SEPs and whether caps are imposed. If the SEP award is insufficient to satisfy the needs of the generator, the IOUs and sellers follow the first right of refusal provisions in the SCT&C
15	Sellers confirm PGC funding with utility	Sellers have 120 days to confirm PGC funding awards, and must transmit notice of PGC funding award to buyers 10 days after CEC provides it
16	CEC signs formal PGC funding award agreements with Seller	PGC funding award agreements are not effective until Sellers have their environmental permits, and the agreement has been approved at CEC business meeting and signed by all parties
17	Utility submits amended advice letters to CPUC with proposed contracts, reflecting SEP awards as	

[3] See Section 5 below.

	needed.	
18	CPUC issues Resolutions approving RPS contracts	ALs are approved pursuant to standard Commission procedure, following CEC signing of PGC funding award agreements

4. Integration Costs

In D.03-06-071, the Commission stated its desire to utilize the Phase I results of the CEC-commissioned study "California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis" (the "Integration Study") in determining the costs associated with integrating renewable resources into the California grid (p. 20). This desire was reiterated in the OIR for this proceeding (R.04-04-026, p. 9).

The Phase I report is now complete, and, with certain exceptions discussed in Section 6 regarding capacity value issues, the results have been endorsed by the CEC and broadly accepted by parties. Two elements of the study, regulation and load following costs, are discussed in this section.

These costs are associated with the ancillary services needed to balance the ISO system in "real time" due to unexpected fluctuations in generation or load. Regulation service is procured by the ISO to balance system fluctuations and maintain frequency levels on a four-second basis, while the supplemental energy market for load-following generation operates on a ten-minute basis. As the Integration Study notes, all generators, whether renewable or conventional, are likely to rely on these ancillary services at some point during their production.

The question in this context is the extent to which the addition of new renewable generation will require a noticeable increase in the provision of these ancillary services. For example, intermittent resources at some degree of penetration may increase the need for ancillary services to provide, in aggregate, a steady and predictable flow of power into the ISO system.

The Integration Study finds that, at present levels of penetration, renewable generation causes no noticeable increase in the cost of these ancillary services, beyond those costs imposed by normal system variability. The Study further finds that, with the addition of "reasonable amounts" of new renewables, the increase in ancillary services costs will be negligible.

The Integration Study therefore recommends, for the first year of RPS solicitations, adders of zero for both regulation and load-following ancillary services costs. These results where vetted in a public process at the CEC, resulting in their affirmation by that agency. Parties to this proceeding, in their opening and reply briefs on least cost/best fit issues, encourage this Commission to adopt these recommendations.[4]

We agree, and find that the utilities should not add any ancillary service costs to the renewable energy bids they receive. This is our determination for the first year of RPS solicitations. We note, however, that the further addition of intermittent renewables to the system may, in future years, cause us to change this determination. Updates to the Integration Study will be useful in this regard. We will be prepared to make these changes to our findings

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[4] Parties advocating this approach include CalWEA, CEERT, GPI, IEP, ORA, and TURN. PG&E, SCE and SDG&E support the use of the Integration Study for determining regulation and load-following costs for this year's solicitation, but suggest that the Commission re-examine the underlying methodology prior to RPS solicitations in 2005 and beyond.

in the future, but for this year, no bid adders for regulation and load following costs should be employed in the LCBF analysis.

5. SEP Award Issues

At the May 24th and 25th CPUC-CEC Collaborative Staff workshop, TURN raised an issue regarding the allocation of Supplemental Energy Payments (SEP) to winning RPS bidders, a task which is the statutory responsibility of the CEC. SEPs are designed to fund some or all of the difference between the final price negotiated between the utility and bidder, and the Market Price Referent (MPR) applicable to the electrical product being procured. The availability of SEPs to cover these supra-MPR costs may be a binding constraint on the amount of renewable energy this Commission can direct the utilities to procure in a given year.[5]

The concern identified by TURN originates in the following apparent inconsistency in the RPS statutes. Pub. Util. Code Section 383.5(d)(2)(A)(iii) directs the CEC as follows:

> "Supplemental energy payments awarded to facilities selected by an electrical corporation pursuant to Article 16 (commencing with Section 399.11) shall be paid for the lesser of 10 years, or the duration of the contract with the electrical corporation."[6]

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[5] Pub. Util. Code § 399.15(b)(4): "If supplemental energy payments from the Energy Commission, in combination with the marker prices approved by the commission, are insufficient to cover the above-market costs of eligible renewable energy resources, the commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable resources that can be procured with available supplemental energy payments."

[6] Section 399.11 et seq. establishes the California Renewables Portfolio Standard Program.

At the same time, Pub. Util. Code § 399.14(a)(4) directs this Commission as follows:

> "In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than 10 years in duration, unless the commission approves of a contract of shorter duration."

In D.03-06-071, the Commission directed the utilities to solicit power purchase agreements for 10, 15 and 20 years, under the assumption that longer-term contracts may result in lower costs to ratepayers.

The problem, as identified by TURN and others in the opening and reply briefs of June 4th and 10th, is that developers will face a potentially dramatic change in the revenue stream associated with their electrical output after year 10 of a PPA. This may cause developers to artificially inflate their bids for the years in which SEPs are available, in an attempt to garner as much financial assistance from the CEC as possible, to the effect that the SEP fund may be prematurely exhausted. Alternatively, bidders may simply be unable to properly structure their bids in the face of this uncertainty, and will find, in years 11 and onward, that they can no longer continue operation. In either case, according to these parties, the cost-effectiveness of the RPS program may be jeopardized. This Commission and the CEC are urged to take quick action to address this contradiction.

Two solutions have been proposed. PG&E, SCE and TURN suggest that the CEC establish an escrow account and deposit sufficient funds to cover SEP awards for years 11 through 20. These accounts would be administered by some entity other than the CEC, to avoid offending the statutory requirement that the CEC only make SEP payments for a maximum of 10 years.

Alternatively, another approach suggested by TURN (and supported by GPI, ORA, and IEP) would have the CEC perform some variant of a Net Present Value (NPV) analysis of the hypothetical stream of SEP payments to a generator of the full term of a PPA; apportion this amount into 10 year's worth of payments; and make these payments over the first ten years of the PPA. Thus, the entire difference between the bid price and the MPR, over the full term of the PPA, is paid in SEPs over the contract's first ten years.

While either of these approaches, in concept, would address the problem addressed by TURN and others, each is flawed in certain important respects. As an initial matter, it is important to recognize the statutory flexibility the CEC has in administering the SEP funds, including establishing caps on the amounts any given generator can receive. This is an important mechanism of cost containment for the RPS program.

Bidders should not assume that they will receive the full difference between their bid price and the MPR in SEP funds. The CEC will weigh a number of factors in making SEP awards each year, and both generators and utilities should be prepared to establish the final parameters of their PPAs in light of the CEC's determinations. Thus, to the extent that both suggested solutions to the SEP problem envision a guaranteed award of the full bid-MPR difference, neither will be adopted in their proposed form here. A variant of these approaches, respecting the statutory authority of the CEC, must be developed.

The first proposal, to establish an escrow account for payments in years 11 and onward, violates the spirit of the RPS statute, if not the letter. We assume the legislature thought it advisable to limit the award of subsidy funds to 10 years, possibly to encourage renewable generators to become cost-competitive without subsidies of any sort in the future. Funneling SEP funds to generators via another mechanism is playing a shell game with Public Goods Charge funds, in violation of the clear intent of the legislature in crafting Section 383.5. Moreover, in encumbering additional funds beyond those needed for years one through 10, the escrow account would further strain limited SEP availability, jeopardizing the attainment of RPS goals. While the CEC may choose to encumber this amount of funds, it is not required to do so. This approach should be rejected.

The second approach, as initially articulated by TURN, poses certain risks regarding the performance incentives for generators outside of the SEP period. A subsequent modification, proposed by IEP, addresses this concern, and we adopt a modified version of it. TURN endorses the IEP approach in its reply brief:

> "Under the IEP approach, the utility would assume payment of the full bid price for all deliveries after year 10 and then calculate, using a net present value analysis, the level of utility payments over the first ten years that would result in total payments equal to the MPR over the life of the contract. The remaining revenues over the first ten years would be provided by SEP awards." (TURN Reply Brief, at p. 10.)

While straightforward, this proposal has the same flaw identified above: it assumes that the generator receives the full difference between its bid and the MPR in SEP funds. In reality, the CEC may determine that an award in some lesser amount is necessary or appropriate. The IEP/TURN procedure should be modified to allow for this possibility.

In making this modification, we note that party approaches to addressing this problem conflate two issues: the number of years covered by SEP payments, and the discontinuity between years 10 and 11 when SEP awards run out. The first issue is of the total value of the SEP award. The second issue is how that total value is distributed over the life of a contract.

The problem, from a bidder's standpoint, is the discontinuity between the SEP and post-SEP revenue streams. While a bidder cannot expect to know, at the time of bid development, the *level* of payments it will ultimately receive in its contract, a rational bid structure would allow the bidder to be confident that its payments will not be subject to a sudden change of unpredictable magnitude during the life of its PPA. Whatever the amount of the SEP award, assuming it is sufficient to meet the generator's needs, the IEP method can be employed to provide this certainty to the bidder.

We will adopt the following structure. Reflecting the important constraint the SEP fund puts on RPS procurement, proposed RPS contracts that require SEP funds submitted by the utility will be provisional, contingent upon the award of sufficient SEP funds to satisfy the needs of the bidder. At the time the utility submits its proposed RPS contracts to the Commission for review, these contracts will simultaneously be forwarded to the CEC. The CEC will perform its analysis of available SEP funds, and make awards according to its criteria and rules. If the SEP is equivalent to the difference between the bid price and the MPR, then it is sufficient for the contract to go forward. If the SEP has been capped such that it does not cover the full amount of the bid price, then the bidder and the utility have an opportunity to renegotiate the bid price.

If the award is sufficient for the contract to go forward, the sum of the MPR and the SEP award, on a cents/kWh basis, will be the final price for the generator's output.

For the following calculation, 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. In a simple example, a 1¢ SEP award for 100,000 kWh of production over ten years yields $1,000. That same $1,000, considered in light of a 20-year contract for 200,000 kWh yields an adjusted SEP of .5¢ kWh. This sum, which we will call the amended bid price, is the utility's obligation in years 11 and onward. As described by TURN, the utility would then, if the generator so desires, recalibrate the utility's payments using a net present value analysis to adjust, "… the level of utility payments over the first ten years that would result in total payments equal to the MPR over the life of the contract. The remaining revenues over the first ten years would be provided by SEP awards." If the CEC's award is insufficient to satisfy the needs of the generator, the contract will not go forward. The utilities should use their weighted average cost of capital (WACC) as the discount rate for this calculation.

This approach allows the utility and generator to structure payments under an RPS contract that will contain appropriate performance incentives throughout the contract term. On an NPV basis, the utility's obligation will not exceed the MPR over the contract term. Importantly, it also allows the CEC to exert competitive pressure on bidders; the IOU, with its payment obligations capped at the MPR and exemptions from RPS procurement available if SEPs run short, would have limited incentive to conserve SEP funds. As stated above, this restructuring of payment terms in light of SEP awards is not required of all contracts. It is available to generators that require funding certainty and to utilities that seek reliable performance incentives in the RPS contracts they ultimately execute. The utilities should allow substantial flexibility in these renegotiations with bidders.

6. Capacity Values

Party discussion of the capacity value of renewable resources generated substantial controversy in workshops and in briefings, and many issues will require further development after the first RPS solicitation is complete. As discussed in the following section, the question of capacity values is implicated in the way in which each utility undertakes its bid analysis, as well as the way in which the MPR calculation is performed. Moreover, as TURN notes in its reply brief, the Commission's evolving resource adequacy rules may impact the manner in which renewable generation capacity is valued.

In light of this possibility, and in recognition of both the substantial remaining controversy and the limited time available to get all of the capacity-related rules precisely right, we will limit our direction here to those issues which require attention before the RFOs can proceed. Below, we will establish a process that we hope will lead to the better integration of the MPR calculation and utility bid analysis, to the effect that capacity issues are addressed uniformly and fairly for all resources. In the interim, we believe that the following discussion, in conjunction with the direction in the section that follows, will provide a reasonable foundation for this year's RPS solicitation.

The immediate capacity issue arises from a focused Commission directive in D.03-06-071 (p. 30), establishing that the capacity value of as-available resources will be set by the Commission with reference to the CEC Integration Study.[7] As-available bidders would have access to this determination

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[7] The values developed in the Integration Study are for each technology's Effective Load Carrying Capability (ELCC), which can be understood as a refined method of calculating capacity that captures its value in relation to system demand. Parties have used ELCC and capacity value interchangeably in briefs. To be precise, what we are

Footnote continued on next page

in structuring their bids, at their discretion. This directive was aimed at resolving ongoing disputes between as-available generators and the utilities regarding the capacity factor of certain technologies. As with the integration costs discussed above, the Commission expressed its desire to use the results of the Integration Study to establish the capacity values, or “credits,” for these generating technologies.

Phase I of the Integration Study has performed a location-specific analysis of the capacity values for biomass, geothermal, solar thermal electric, and wind generators in California. Of these four technologies, biomass and geothermal are not as-available resources, and we therefore do not adopt capacity values for them here.

For wind resources, we adopt a capacity value that is an average of those found in the Integration Study for the existing resources in the state’s three principal wind resource areas (Altamont, San Gorgonio, and Tehachapi): 24%. While recognizing that this is a very rough approximation, we emphasize the purpose of this determination: to provide a lower bound to the capacity value a utility should impute to a wind resource bid into its RPS solicitation.

The Integration Study analysis examined existing wind resources in these areas, looking at the performance of many older turbines whose technology and performance are inferior to that of today’s wind generating technology. Accordingly, the capacity value of the new wind generators that may bid into an RPS solicitation may be higher than this baseline capacity value. Wind bidders

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adopting here are ELCC values, and we endorse the continued use of ELCC calculations in future RPS policy development, as embodied in scheduled updates to the Integration Study and subsequent Commission decisions.

should be prepared to support any claims of higher capacity values with site-specific data. Utilities should provide details of their analysis of these claims to their PRGs.

Integration Study results for the other as-available technology under consideration here, solar thermal electric, were disputed by parties and ultimately repudiated by the study's authors before adoption of the report. The results, 56.6%, do not appear to be consistent with the experience of solar thermal facilities in California, which have demonstrated availability in the high-90% range.[8] In keeping with the recommendation of the authors, we will not adopt the Integration Study's finding for solar thermal electric facilities, and will look to updates of the report for better guidance in the future.

No party provided concrete proposals for establishing the capacity value of solar thermal electric facilities in absence of the Integration Study findings, leaving us with no reasonable basis for making this determination. We will therefore leave the ultimate determination of capacity values for these solar technologies to the negotiation between bidder and utility. Bidders should provide substantial support for the output profile they will submit in response to the RFOs, and the capacity value that underlies it, and utilities should provide their analysis of this output profile to their PRGs for consideration. Similarly, the Integration Study findings do not estimate a capacity value for small hydroelectric facilities which may be considered as-available resources. The capacity value for these technologies should be determined through a similar

[8] When paired with gas-assist generation. The portion of the output from these facilities that would be considered "renewable" is subject to the rules set forth by the CEC in establishing RPS eligibility.

negotiation process with opportunity for PRG review. Again, we anticipate that updates to the Integration Study will enable us to provide more guidance on this issue in the future.

Another aspect of the capacity issue requires attention here. In response to concerns expressed at the May 25th workshop regarding the direction in D.03-06-071, described in CalWEA's Opening Brief of June 4th, we state that separate capacity payments from the utility are not mandatory. The language that CalWEA suggests may be the source of this confusion, Conclusion of Law 17, establishes only that the Commission will not set capacity values for firm renewable resources.[9] What we establish here, in limited fashion, is a baseline level of capacity value for wind resources. The manner in which these capacity values should be employed in the LCBF process is discussed in Section 7 below.

7. Bid Evaluation Process Issues

a) Applying the MPR to RPS Bids

This section addresses certain issues raised by parties regarding the interaction of the Market Price Referent and the electrical products bid into an RPS solicitation.[10] As an initial matter, we will give direction on proposed changes to the MPR methodology for use in future RPS solicitations. Specifically, parties have recently recommended a change to the Commission's methodology, one that would utilize a "time of delivery profile" to more accurately reflect the

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[9] Conclusion of Law 17 states that "The Commission will not establish capacity values for firm resources; these resources will bid their own estimations of energy and capacity values." The bidding of an estimated capacity value does not equate to a mandatory capacity payment.

[10] In response to party comment, we clarify that initial bid ranking should take place without regard to the MPR. The following discussion advances the manner in which a utility will determine whether ranked bids are above or below the appropriate referent.

value of electricity provided to the utility over all the hours in the year. We will refer to this concept as the TOD method.

The methodology adopted in D.04-06-015 will produce MPRs for two products, baseload and peaking generation, calculated for the length of the proposed RPS contract. This approach was initially endorsed by the Commission in D.03-06-071 as consistent with the RPS statute and appropriate for the first RPS solicitation.[11] The staff MPR whitepaper, subsequent workshops, and party briefing all focused on this approach. As discussed below, this two-MPR approach, while less precise than the TOD method, is workable for this year's solicitation, and we will not change it now.

We recognize, however, that the TOD method may have a number of advantages by virtue of its precision and transparency. The method, an initial version of which was first introduced by GPI in its April 1, 2003 testimony in the predecessor to this Rulemaking (R.01-10-024), would effectively establish a payment schedule for each of the 8760 hours in the year. Generators would bid an output profile, for example 2000 hours per year delivered at specific times, and the value of the bid would be judged by comparing this profile to a TOD payment schedule adopted by this Commission.

[11] Pub. Util. Code § 399.15(c): "The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following: (1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the commission. (2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities. (3) The value of different products including baseload, peaking, and as-available output."

A number of parties have subsequently endorsed some variant of this approach and encouraged the Commission to begin examining it soon, for implementation in advance of next year's RPS round.[12] Suggested benefits include a more accurate estimation of the value of capacity, avoidance of problems associated with applying MPRs to products that are neither strictly baseload nor peaking, and better fit with one of the utilities' proposed method of evaluating RPS bids. This proposed method is discussed in Subsection C below.

We agree that the TOD method is potentially superior to the two-MPR methodology we will employ this year, and we direct staff to begin exploring it expeditiously. Staff should utilize the period during which the first RPS solicitations are in progress to develop a plan for building a record on TOD methods. We are particularly interested to understand how the TOD profile would be constructed, how public it would be, and whether separate TOD profiles for each utility would be appropriate. We will also want to consider the role of ELCC in constructing these TOD profiles, and the role of separate capacity payments, if any are appropriate, under the payment methods that will result. We direct Staff to consult with the CEC regarding how any proposed changes may affect that agency's administration SEPs. Finally, while the TOD method appears to be consistent with RPS statute, we will want to develop a record to fully support this conclusion.

The TOD method, if adopted, will address the problem of applying MPRs to products that do not fit the baseload or peaking categories. For this

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[12] Parties supporting the evaluation of a TOD method include: TURN (Opening Brief, at p 8); SDG&E (Opening Brief, at p.11); PG&E (Opening Brief, at p. 11); and SCE (Reply Brief, at p. 5).

year's solicitation, however, we will need to address this issue with the MPR methodology adopted in D.04-06-015. In response to the briefing outline prepared by staff, parties submitted commentary on this point in their opening and reply briefs.

Certain renewable generation technologies will generate an output profile that is both on- and off-peak. The utilities must understand how the Commission expects them to apply the MPRs in evaluating bids from these resources, to establish the separation between the utility's financial obligation and the portion of a bid that is eligible for SEPs from the CEC. The MPR also establishes the upper bound for contract prices that will be considered *per se* reasonable upon acceptance by the Commission. The treatment of these "intermediate" products is therefore an important piece of the LCBF analysis.

Parties offer a number of proposals to address this issue. In adopting one, we reiterate that the method will be employed for this year only, as the MPR methodology may be updated for 2005. Further, we note that the number of bidders to whom the adopted approach will apply is likely to be limited. What we seek is a workable means of addressing the problem as our methodologies continue to improve.

IEP, in its opening brief, offers the simplest solution: the Commission could do nothing, and await evidence from the bid results that will aid in addressing the problem in the future. While this is an appealing approach in light of the schedule, we choose to take a more affirmative step.

SCE proposes that the Commission calculate an "intermediate" MPR in addition to the baseload and peaking MPRs ordered in D.04-06-015. The utility notes that the model can calculate MPRs for any capacity factor that is input, and thus could accept a capacity value anywhere in the range between peaking and baseload facilities. While this approach is analytically feasible, we do not wish to revisit the determinations in D.04-06-015 at this time.

ORA proposes a “straightforward spreadsheet and a six-step formula,” originally discussed in its briefs on MPR issues (ORA Reply Brief, p. 2). While this approach may have merit, it is difficult to make a full determination from the brief discussion provided in the brief. The proposal elicited a protest from SCE when originally offered, and the ensuing debate revealed substantial differences between the parties. For these reasons we do not see fit to adopt the ORA proposal at this time.

SDG&E proposes to establish its peak period in its RFO, and “renewables offering at least 70% of the energy output delivered during this period would be considered a peaking product”(SDG&E Reply Brief, p. 3). The utility advocates this approach for its simplicity, and urges the Commission to grant the utilities flexibility in evaluating products for this solicitation. While we are willing to grant the utilities all reasonable flexibility, this approach is too imprecise, in that it will potentially result in ratepayers over-paying for 30% of a renewable facility’s output.

The remaining options, proposed by TURN and PG&E, are variations on the concept of “blending” the peaker and baseload MPRs based on the relative delivery of a generator on- and off-peak. The TURN proposal, while less precise than PG&E’s, is straightforward and more easily implemented. As described in TURN’s Opening Brief:

> “Under this concept, the peaker MPR would apply to a fixed number of delivery hours based on the capacity factor chosen in the MPR model (*e.g.*, 20% capacity factor x 8,760 = 1752 hours). If a solar thermal facility offered 2,500 hours/year of peak-oriented deliveries, then the pricing could be

> benchmarked against a weighted average of the peaker MPR (1,752 hours) and the baseload MPR (748 hours)."

Without adopting the proposed capacity factor of 20%, we will endorse this method for the first round of RPS solicitations, with the following restrictions.

At the time the MPRs are released, the Commission will identify the capacity factor utilized in calculating the peaking MPR.[13] The Commission will allow the utilities discretion to allocate the number of hours inherent in this capacity factor to match their particular peak periods. This allocation should comport with the guidance on this subject the utilities will provide to bidders in their RFOs. The utility's description of its peak period should encompass the range of reasonable determinations by this Commission regarding the capacity value of a peaking resource. The utility should then apply the weighted-average blending method proposed by TURN to only those products that very clearly do not fit in the baseload or peaking categories. We do not expect that this blending will be necessary or appropriate for the substantial majority of the bids received by the utility. To insure transparency in this process, the utilities should be prepared to discuss any utilization of this method with their PRGs.

b) Qualitative & Quantitative Factors Used in Bid Evaluation

D.03-06-071 instructed renewable bidders to describe potential benefits of their projects, identifying local reliability, low income or minority communities, environmental stewardship, resource diversity, curtailabilty, and

[13] This process is necessary to prevent bidders from utilizing this important variable to approximate the peaking MPR when preparing bids.

dispatchability as attributes to be considered. The utilities were also directed to apply transparent criteria in evaluating such claims, and share the results of these evaluations with their PRGs for consideration.

In their comments the parties focused on the attributes listed below, identifying (1) qualitative attributes to be used to differentiate tie-breakers and (2) quantitative attributes to be used in the first ranking of bids.

- resource diversity
- benefits to minority and low income communities
- environmental stewardship
- local reliability
- curtailment and dispatchability
- repowering

In their briefs, PG&E, SCE, TURN, CalWEA, IEP, and ORA identified curtailment and dispatchability as quantitative attributes to be used in the first ranking of bids. SCE, CalWEA, and IEP identified local reliability as a quantitative attribute. Lastly, TURN, PG&E, and CalWEA identified repowering as a quantitative attribute. All other attributes were identified as qualitative and perhaps considered as tie-breakers.

SDG&E was the only party to consider all attributes to be qualitative. SDG&E did note that curtailment and dispatchability are quantifiable attributes, but will only model for large projects during the bid evaluation process (SDG&E Reply Brief, p. 3). They argued that they should not be required to perform curtailment/dispatchability analysis on all bids, especially if the projects are so small that utility operations would not be materially impacted by these attributes.

With regard to the issue of repowering, CalWEA argues that the Commission should issue guidelines regarding fair evaluation of any repowering proposals (CalWEA Opening Brief, p. 13). Specifically, CalWEA suggests that the Commission direct utilities to: (1) expressly solicit repowered bids; (2) credit the bid with the cost savings accrued by replacing an existing contract; (3) apply no transmission adder if a repowered facility does not increase its nameplate capacity; and (4) evaluate repowering proposals for any remarketing benefits that would accrue as compared to the replaced contract.

Likewise, TURN recommends that any bid from a QF seeking to repower or extend an existing contract should be credited with savings relative to otherwise applicable payment terms. (TURN Opening Brief, p. 7.)

PG&E responded to TURN/CalWEA's proposal for crediting repowered bidders the above market value of their restructured contracts. PG&E argues that it is important that excessive value is not attributed to repowering. "The value of pre-existing contractual obligations should be realistic and … the amount of credit generated by the repowering must be limited to the historical output of the project before repowering." (PG&E Reply Brief, pp. 9-10.) In their reply briefs, SDG&E and SCE support repowering, but do not agree with CalWEA's proposal that existing renewable projects should be awarded the above-market value of their existing contracts. They argue that the record is insufficient to support this crediting, which would give repowered bidders preferential treatment.

D.03-06-071 directs the utilities to apply transparent criteria in evaluating the tie-breakers used to rank bids. To ensure transparent and consistent criteria, for the 2004 RPS solicitation we identify curtailability, dispatchability, and repowering as quantitative attributes that the utilities need to incorporate into their bid evaluation process. All other attributes are to be considered qualitative given that there is an inadequate record on how to monetize these attributes.

With regard to the Commission adopting specific methodology for evaluating the bids from repowered facilities, we decline to do so for the 2004 RPS solicitation. The Commission supports utility evaluation methodologies that would credit repowered bidders for additional benefits provided as a result of contract restructuring. However, the record does not contain a sufficiently detailed proposal for a specific guideline or crediting method at this time. Therefore, rather than approving a specific methodology, we will adopt the general guideline that repowered bidders should expect to receive credit for the benefits they provide, subject to the individual circumstances of each bid. The development of more specific guidelines for evaluating repowering may be addressed in the future.

We find that attributes relating to curtailment, dispatchability, and repowering are properly considered quantitative, and should be evaluated using quantitative methods. Each utility should develop a quantitative method that is feasible in light of its overall evaluation methodology, and share the method and results with its PRG. We are not requiring the utilities to perform detailed quantitative analyses on these issues. Rather, we are concerned that the methods used by the utilities to value these attributes be transparent and give sufficient weight to what may be significant benefits provided by particular renewable projects. Bearing in mind the limited guidance we provide here, we will grant the utilities substantial flexibility in the implementation of this aspect of our order.

The parties also raised the issues of tie-breakers and their role in bid evaluation. GPI noted that while it is difficult to quantify externality factors, using them only as tie-breakers fails to recognize the difference in attributes between projects (GPI Opening Brief, p. 5). TURN expands upon this point, stating that using qualitative factors as tie-breakers is problematic since the probability of an actual tie is somewhat remote. In addition, TURN notes that the Commission has not identified what price differential would count as a tie, thus making the "… use of qualitative benefits to tip the balance only in the case of identical adjusted bids scores meaningless." (TURN Reply Brief, p. 4.) Consequently, TURN recommends that the presence of verified qualitative factors be used to justify moving a bid onto the short list – subject to two conditions: (1) bid rank should be within reasonable price proximity to those selected for the short-list, and (2) the utility should consult with, and receive general support from, its PRG prior to elevating a bid based on qualitative factors. (TURN Reply Brief, p. 5.)

We agree that the use qualitative attributes as tie-breakers in the bid evaluation process is challenging. Nonetheless, the Commission has consistently stated its interest in seeing these factors employed in bid ranking. TURN's proposal that verified qualitative factors be used to justify moving a bid onto the short-list, subject to the two conditions listed above, is a reasonable approach to take for this solicitation. As ordered in D.03-06-071, the utilities should apply transparent criteria in evaluating qualitative attributes and share the results of these evaluations with their PRG for consideration.

c) Proposed Utility Approaches

Each utility has proposed a different method of analyzing bids received in the RPS solicitation. All are workable, and, with the incorporation of the guidance above regarding integration costs, capacity values, "blended" MPRs, and quantitative/qualitative bid attributes in addition to the utility-specific guidance provided below, they are approved for this year's RPS solicitation.

No party expressed opposition to the utilities' use of divergent methods in performing the LCBF analysis. In its opening brief, IEP recommended that "bid evaluation determinants (*i.e.*, factors) should be open, transparent, and non-discriminatory" (p. 2), a proposal subsequently endorsed by CEERT (Reply Brief, p. 3). We endorse this principle, and direct the utilities to implement it by giving clear guidance in their RFOs regarding the evaluation methodology they will employ, incorporating the direction in this decision.

We describe each of the utilities' proposed methodology below, indicate where the direction on integration costs, capacity values and blended MPRs should be applied, and give particular direction on certain issues specific to each approach.

As a preliminary matter we will address one issue that arose in briefs, resolution of which will apply uniformly to all three utilities. SCE proposes to utilize a "debt equivalence component" (Opening Brief, p. 6) in evaluating bids. Per D.04-01-050, the issue of debt equivalence will be considered in a detailed manner in each utility's cost of capital proceedings. The utilities should not employ debt equivalency considerations in evaluating RPS bids at this time, as the Commission has no approved methodology for doing so, and such an analysis may discourage the long-term renewable energy contracts the Commission has indicated it favors.

SDG&E: As described in its opening brief, SDG&E plans to emphasize three components in its LCBF analysis: energy cost delivered to

SP-15; overall fit with the utility's resource portfolio; and transmission system upgrade costs (SDG&E Opening Brief, p. 8). The assessment of portfolio fit will be in relation to the supply and demand balance identified in SDG&E Long-Term Resource Plan. The utility will not employ production simulation modeling for each bid, relying instead on the match of a bidder's output profile with the needs identified in the Plan. SDG&E's evaluation process and results will be made available to its PRG for review and input.

CalWEA argues that SDG&E should be forced to employ the bid evaluation methodology employed by either SCE or PG&E (CalWEA reply brief, p. 6). This argument appears to be motivated by CalWEA's desire to see the capacity values adopted in the CEC Integration Study employed in SDG&E's analysis. As directed above, SDG&E should employ the average of the Integration Study's findings for wind, 24%, as the minimum level of capacity credit to assign to wind facilities. Given this direction, we do not order SDG&E's to adopt the evaluation methodology of either SCE on SDG&E.

SDG&E requests flexibility in implementing its evaluation methodology, and, in general, such flexibility is warranted. SDG&E should follow the direction provided in this decision regarding integration costs, capacity values, blended MPRs, and quantitative/qualitative bid attributes should be forthcoming with its PRG in discussing its evaluation methods. With these caveats, SDG&E's proposed LCBF methodology is approved.

SCE*:* While also relying on the needs identified in its Long-Term Resource Plan, SCE's LCBF analysis would employ a production simulation model "to calculate the total system production benefits and costs associated with a renewable project" (SCE Reply Brief, p. 3). By incorporating ELCC values, transmission costs, and integration cost and benefits, this analysis will, according to SCE, produce a cost/benefit ratio for each bid. This ratio will then be used to compare the bids received.

A key input into this cost/benefit modeling approach will be the ELCC value associated with the bid, as this will drive the determination of the value of the bidder's generation. We reiterate our direction that SCE should follow the capacity value guidelines provided above, and should provide its assumptions and results to its PRG for review. As described above, no adders for integration costs should be employed.

ORA endorses the SCE approach by virtue of its explicit adoption of ELCC values (ORA Opening Brief, p. 3). We agree that the proposed method outlined by SCE is appropriate for this year's solicitation, and with the caveats noted above, it is approved.

PG&E: PG&E's proposed LCBF methodology focuses on four areas: determination of the market value of the bid; calculation of transmission adders and integration costs; evaluation of portfolio fit; and consideration of non-price factors (Opening Brief, p. 4). These are roughly the same criteria to be employed by SDG&E and SCE, with one important difference.

PG&E's proposal for determination of the "market value of the bid" employs the utility's calculation of a time of delivery (TOD) profile, utilizing the utility's proprietary forward price curve. This TOD profile subsumes the value of a generator's capacity into the price received for its electricity at a specific point in the 8,760 hours of potential utility need. This is a significant difference between the PG&E approach and those advocated by SCE and SDG&E.

No party expressed strong concern with the PG&E approach, and several parties expressed support for it (CalWEA Opening Brief, p. 6; CEERT Reply Brief, p. 4). Parties generally agree that the PG&E approach eliminates the need for separate ELCC values. We will therefore not require PG&E to utilize the Integration Study's ELCC findings. It appears that the TOD profile method provides an appropriate value for capacity independently of these ELCC calculations.

TURN conditions its support for the PG&E proposal with the requirement that the delivery profile submitted by the bidder be used both to evaluate the project and to determine payments under the resulting contract. In TURN's view, such a requirement would eliminate the incentive for bidders to "overestimate peak period deliveries in order to secure a contract" (Opening Brief, p. 6). In its reply brief, PG&E states it "agrees that actual payments should reflect bid profiles" and "intends to make time-differentiated payments, so that a bidder received 100% of its bid price if the project delivers the exact number of hours at the times projected by the delivery profile" (Reply Brief, p. 6-7). PG&E should conform its analysis to be consistent with this principle.

ORA and CalWEA express concern regarding the definition of "peak" hours in PG&E's proposed TOD profile (Opening Briefs, pp. 3 and 9, respectively). These parties are concerned that the utility's peak will be defined too narrowly, and will exclude the output of facilities that should properly be considered peaking. In its reply brief, PG&E pledges to offer guidance in its RFO on its definition of "peak." We note the interaction of this definition with the discussion of the "blended" MPR above. As directed above for all three utilities, PG&E should define its peak broadly enough to encompass the range of reasonable determinations by this Commission regarding the capacity value of a peaking resource.

Only the whole, PG&E's proposed evaluation methodology is sound. Parties also observed that this method of analyzing the value of a bidder's output would meld cleanly with the proposal for a TOD method of calculating the MPR, as discussed above. PG&E's use of a TOD profile will thus potentially provide valuable information on how to implement such a change in the future. With the caveats discussed above regarding the linking of payments to bid profiles, the definition of "peak," and the direction provided on integration costs, the blended MPR, and quantitative/qualitative bid attributes, PG&E's evaluation methodology is approved.

8. PRG Review Issues

Two issues were raised regarding PRG review of the RFOs and subsequent bid evaluation process. First, SCE suggests that Commission and Collaborative staff not participate in PRG activities prior to the release of the MPR (with special meetings of the PRG, excluding Commission and Collaborative staff, being convened if necessary to review bid results prior to the release of the MPR), in order to avoid a violation of the statutory requirement in Cal. Pub. Util. Code Section 399.14(a)(2)(a) that the MPR be disclosed only after the closing date of a competitive solicitation. SCE SDG&E, TURN and IEP support this position as well. This position is consistent with the Commission's decision in D.04-06-015 and will be adopted.

Second, IEP claims that a critical component of a transparent, competitive procurement process is that public stakeholders, including bidders, receive information related to the key factors in bid evaluation (including, as appropriate, modeling inputs and assumptions) simultaneously in advance of the bid submission, preferably at the time of the release of the RFO. IEP suggests that while the PRG can assist the utilities in reviewing bids, they need not and should not receive any modeling inputs and assumptions separate from what is publicly available. IEP requests that the Commission prohibit the utilities from sharing "any modeling inputs and assumptions" to the PRG unless such information is also made publicly available. IEP suggests that this is necessary to prevent "leaks" of information to "potential, select bidders."

SD&GE and TURN object to IEP's proposal. SDG&E claims that the modeling inputs and assumptions relating to bid evaluation are confidential and that releasing this information to the public would provide an unfair advantage to bidders at the expense of utility customers. TURN agrees that this information should not be provided to the public, but asserts that, without this type of information, the PRG members would be unable to verify the legitimacy of the application of Commission-approved evaluation criteria to individual bidders and would not be able to provide the necessary feedback to the utilities. Both SDG&E and TURN point out that PRG members are bound by non-disclosure agreements from disclosing any such information.

We will reject IEP's proposal to require that any information that is released to the PRGs also be automatically, and simultaneously released to the public. The intent of the PRG is to allow non-market participants to provide guidance to the utilities in the preparation of the RFOs and the evaluation of bids and as noted by SDG&E and TURN, PRG members have signed Protective Orders that prohibit the release of confidential information. In R.01-10-024, the prior procurement rulemaking, we have consistently sought to provide reasonable access to information to all interested parties. Among other things, we have adopted a series of Protective Orders, which provide interested parties, including market participants under certain conditions, with access to confidential information.[14] We intend to continue to provide this same type and degree of access and transparency in the instant rulemaking.

Finally, TURN requests that the Commission require each utility to provide a summary of all bid evaluations adjustments to its PRG prior to the compilation of a short list. After allowing the PRG to review and comment on the evaluation results, the utility should identify a short list and begin negotiations with individual bidders. TURN also requests that, when final advice letter filing are made seeking approval of individual contracts, the utility should be required to transmit to the PRG its final analysis and ranking of all received bids, including raw bid pricing, each separate quantitative adjustment used in the analysis, and re-ranking resulting from qualitative factors, and the final score for each bid. This level of transparency should give the Commission confidence that the final selection process was consistent with least-cost, best-fit requirements. TURN's request is reasonable and should be adopted.

IV. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Peter V. Allen and Julie M. Halligan are the assigned Administrative Law Judges for this proceeding.

V. Shortening the Public Review Period of the Draft Decision

In order to reach the goal of attaining a target of 20% renewable energy for the State of California, we have committed to the expeditious implementation of SB 1078. In light of the fact that the legislature has found that increasing

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[14] See, ALJ's Ruling Adopting Amended Protective Order and Severing an issue for hearing, dated January 14, 2004.

California's reliance on renewable energy may have significant economic, social, health, and environmental benefits,[15] we find, on our own motion, that the public necessity requires that the 30-day period for public review and comment provided in Public Utilities Code Section 311(g) be reduced so that the utilities can issue RFOs for renewable generation resources in July, 2004. Only by issuing a decision on the least-cost, best-fit evaluation criteria promptly can we effectively facilitate the utilities' attempts to comply with the Annual Procurement Target requirements for this calendar year. In shortening the comment period, we have carefully balanced the public interest in avoiding harm to the public welfare resulting from delay in considering this draft decision against the public interest in having the full 30-day period for review and comment required by Rule 77. We conclude that the former outweighs the latter and that failure to shorten the comment period for this draft decision would cause significant harm to the public welfare. Accordingly, we reduce the comment period for this draft decision. Comments on the draft decision are due at noon on July 2, 2004, and reply comments are due at noon on July 6, 2004.

VI. Comments on the Draft Decision

Opening comments were filed by PG&E, SDG&E, SCE, ORA, CEERT, GPI, Calpine, and UCS. Reply comments were filed by PG&E, SDG&E, SCE, CalWEA, UCS, and TURN.[16] We have reviewed the comments filed, and made changes to the Draft Decision as appropriate.

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[15] Public Utilities Code Section 399.11

[16] TURN did not file opening comments.

Findings of Fact

1. Pub. Util. Code §§ 399.14(a)(2)(B) requires the Commission to adopt a process and methodology for establishing a least-cost and best-fit evaluation criteria to be used in implementing the RPS program.

2. Commission D.03-06-071, as modified by D.03-12-065, began the process of developing the least-cost and best-fit criteria.

3. The Commission has considered the record in this proceeding and in the RPS phase of R.01-10-024, the previous procurement rulemaking.

4. The Commission and CEC Collaborative staff have held a workshop and received comments on the subject of least-cost and best-fit evaluation criteria.

5. It is reasonable to permit bidders to participate in more than one utility's RPS solicitation.

6. The utilities should issue RFOs for renewable generation resources consistent with the approved renewable procurement plans.

7. Pursuant to Pub. Util. Code § 399.14(a)(2)(A), Commission and collaborative staff should not participate in the procurement review groups until after the MPR has been disclosed. ORA may participate in the procurement review groups before the MPR is disclosed, as it is not part of the collaborative staff.

8. D.04-06-014 established a window from June 30, 2004 to July 15, 2004, during which utilities must issue Requests for Offers consistent with their approved renewable procurement plans.

9. It is reasonable to modify the adopted solicitation window to allow the utilities to revise their RFOs consistent with the orders adopted in today's decision.

10. It is premature to decide when the utilities should issue RFOs in 2005 and subsequent years.

11. It is reasonable to require bidders that have been "short-listed" to withdraw competing bids, to avoid the situation in which the utilities are negotiating against one another for the same project, potentially resulting in inflated prices.

12. Requiring bidders to withdraw competing offers after being notified that they are on a utility's short-list eliminates the need to require bidders to identify whether or not they have submitted multiple bids.

13. All bids should be treated as potentially multiple until the bids are short-listed and negotiations begin.

14. Given the fluid nature of the solicitation and contract approval process, it is not reasonable to adopt a rigid solicitation schedule.

15. The Integration Study finds that, at present levels of penetration, renewable generation causes no noticeable increase in the cost of ancillary services beyond those costs imposed by normal system variability.

16. The results of the Integration Study have been reviewed and affirmed by the California Energy Commission.

17. It is reasonable to use the results of the Integration Study for the 2004 RPS solicitation and adopt the Integration Study's findings of zero adders for regulation and load-following costs.

18. The CEC has statutory flexibility in administering the SEP funds, including establishing caps on the amounts any generator can receive.

19. For the initial RPS procurement, it is reasonable to allow the utility and the bidder to renegotiate the bid price or utility payment following the CEC's determination on any requested Supplemental Energy Payments to allow the

utility and generator to structure payments under an RPS contract such that the contract provides appropriate performance incentives throughout the contract term.

20. The utilities should use their weighted average cost of capital (WACC) as the discount rate in calculating the level of utility payments over the first ten years that would result in total payments equal to the MPR over the life of the contract.

21. For wind resources, it is reasonable to adopt a capacity value that is an average of the capacity values found in the Integration Study for the existing resources in California's three principal wind areas (Altamont, San Gorgonio, and Tehachapi): 24%.

22. We do not adopt the Integration Study results for solar thermal electric resources, as these results were repudiated by the study's authors before adoption of the report.

23. Capacity values for solar thermal electric resources should be subject to negotiation between the bidder and the utility.

24. The Integration Study findings do not provide a capacity value for small hydro facilities.

25. Capacity values for small hydro should be subject to negotiation between the bidder and the utility.

26. The TURN proposal for "blending" the peaker and baseload MPRs is reasonable for use in the initial RPS solicitations, with the clarification that the Commission will identify the capacity factor used in calculating the peaking MPR and the utilities will have the discretion to allocate the number of hours inherent in this capacity factor to match their individual peak periods.

27. Utilities should treat curtailability, dispatchability, local reliability, and repowering as quantitative attributes.

28. All other potential benefits associated with renewable resources, such as benefits to low income or minority communities, environmental stewardship, local reliability, and resource diversity should be treated as qualitative attributes.

29. The presence of demonstrated qualitative attributes should be used to justify moving a bid onto the short list subject to two conditions: (1) the initial bid rank should be within reasonable price proximity to those selected for the short-list and (2) the utility should consult with, and receive support from, its PRG prior to elevating a bid based on qualitative factors.

30. The issue of debt equivalency is being considered in each utility's cost of capital proceeding.

31. SDG&E and SCE should use the average of the Integration Study's findings for wind, 24% as the minimum level of capacity credit to assign to wind facilities.

32. PG&E's time of delivery profile method provides an appropriate value for capacity independent of the Effective Load Carrying Capability calculations and is reasonable for use in the initial RPS solicitation.

33. Commission and CEC Collaborative staff should not participate in the PRG activities prior to the release of the MPR.

Conclusions of Law

1. There is an adequate record in R.01-10-024 and in this proceeding to adopt criteria for the rank ordering and selection of least-cost, best-fit renewable resources.

2. The process adopted for the ranking of bids is consistent with the statutory requirements.

3. Pursuant to Rule 77.7(f)(9), we find that public necessity requires a reduction of the 30-day period for public review and comment on this draft decision because failure of the Commission to act on July 9, 2004, could endanger the public's health and welfare, and this clearly outweighs the public interest in allowing the full 30-day period for public review and comment.

4. Utilities should not add any ancillary service costs to the renewable energy bids they receive.

5. Allowing the utility and generator to structure payments under an RPS contract to ensure consistent performance incentives over the contract term is consistent with the intent of the RPS statute.

6. Utilities should apply a blended peaking and baseload MPR to products that do not fit squarely in either category.

7. The utilities should not use debt equivalency considerations in evaluating RPS bids at this time because the Commission has not approved a method for doing so, and debt equivalency analyses may discourage the long-term renewable energy contracts the Commission has indicated it favors.

8. With the requirement that SDG&E follow the direction provided above regarding integration costs, capacity values, and blended MPRs, SDG&E's proposed bid evaluation method is reasonable for use in the initial RPS solicitation and should be approved.

9. With the caveats regarding the linking of payments to bid profiles, the definition of peak, an the direction provided on integration costs and the blended MPR, as discussed above, PG&E's bid evaluation method is reasonable for use in the initial RPS solicitation and should be approved.

10. With the caveat that SCE should follow the capacity value guidelines provided above, and should provide its assumptions and results to its PRG for

review, the proposed method for bid evaluation outlined by SCE is appropriate for this year's solicitation.

11. The utilities should issue RFOs for renewable generation resources consistent with today's decision and their approved renewable procurement plans.

12. In order to proceed expeditiously with RPS procurement, this order should be effective today.

O R D E R

IT IS ORDERED that:

1. A least-cost, best-fit methodology is adopted, as described above, consistent with the preceding Findings of Fact and Conclusions of Law.

2. The Assigned Commissioner and Assigned Administrative Law Judges will make such rulings as are necessary to effectuate this order.

3. The three major utilities have from July 9, 2004 to July 15, 2004 to issue their Requests for Offers for renewable generation resources, consistent with this order and their renewable procurement plans as approved by the Energy Division.

This order is effective today.

Dated July 8, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN

SUSAN P. KENNEDY
Commissioners