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Decision 06-05-039 May 25, 2006

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 CONDITIONALLY APPROVING PROCUREMENT PLANS FOR 2006 RPS SOLICITATIONS, ADDRESSING TOD BENCHMARKING METHODOLOGY, AND CLOSING PROCEEDING

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OPINION CONDITIONALLY APPROVING PROCUREMENT PLANS FOR 2006 RPS SOLICITATIONS, ADDRESSING TOD BENCHMARKING METHODOLOGY, AND CLOSING PROCEEDING

I. Summary

Each California electrical corporation is required each year to procure a minimum amount of electricity from eligible renewable energy resources, eventually reaching procurement equal to 20% of total retail sales. To fulfill this requirement, each electrical corporation must prepare a procurement plan (Plan). The Commission is required to review and accept, modify or reject each Plan.

In this order, we conditionally approve for the next procurement cycle each proposed renewables portfolio standard (RPS) procurement Plan and draft request for offer (RFO) filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). In doing so, the important steps we take include:

1. Adopt PG&E's proposal to allow deliveries anywhere in California

2. Agree with PG&E, SCE and SDG&E (collectively Investor-Owned Utilities (IOUs)) and decline to adopt an Incremental Procurement Target (IPT) of 1.2%, but, in exchange:

    a. stress the importance of each IOU continuing to include its own procurement margin of safety

    b. adopt limited additional reporting on the progress of each project meeting its development and initial operation milestones

3. Retain existing flexible compliance rules by declining to adopt full earmarking or flexible compliance for 2010

4. Encourage, and in some cases direct, IOUs to:

   a. consider whether or not to build their own renewable generation

   b. consider reducing bid and other deposits

   c. not employ resource stacks in resource selections

   d. amend Plans to reflect renewable resource neutrality

   e. amend Plans to address California Independent System Operator (CAISO) market redesign

   f. reconsider disclaimers and elements of IOU discretion

5. Remove barriers to program success by adopting the following measures:

   a. require IOUs to report on evaluation criteria and solicitation results, as recommended by Aglet Consumer Alliance (Aglet)

   b. require that IOUs use an Independent Evaluator to separately evaluate and report on the entire procurement process

   c. encourage each IOU to hold workshops it believes will advance the program

   d. note parties may consider use of the many alternative dispute resolution (ADR) tools available at the Commission

e. require IOUs to include an equal treatment, fair dealing and good faith requirement in their RFOs

f. require IOUs to include a clear and consistent statement of evaluation criteria in their Plans

g. provide clarity on environmental stewardship and the relationship to the Commission's Water Action Plan

h. permit multiple simultaneous bids

6. Address limited elements unique to each IOU's Plan, such as

a. clarify treatment of transmission (PG&E and SDG&E)

b. include references, where appropriate, to Commission General Order (GO) 167 (PG&E and SCE)

c. include payment of interest on deposits (SCE)

d. include IPT (SDG&E)

e. strongly encourage a 2006 solicitation (SDG&E)

7. Adopt a schedule for the next solicitation cycle (see Appendix A)

PG&E, SCE and SDG&E shall submit amended Plans and amended RFOs to the Director of the Energy Division within 15 days of the date of this order. Unless suspended by the Energy Division Director within 20 days of the date of this order, each utility shall proceed to use its amended Plan and RFO for its 2006 RPS program and solicitation.

We continue to employ the presumption that utilities are able to use their business judgment in running their solicitations, with the guidance we provide and within the parameters we establish. Utilities ultimately remain responsible for program success, within application of flexible compliance criteria. We will later judge the extent of that success, including the degree to which each IOU elects to take the guidance provided herein, demonstrates creativity and vigor in program execution, and reaches program targets and requirements.

We also here address issues related to a time of delivery (TOD) benchmarking methodology. We adopt TOD factors, but decline to adopt a specific benchmarking methodology.

All issues which need to be addressed in Rulemaking (R.) 04-04-026 are now resolved. We incorporate the record in this proceeding into a new Order Instituting Rulemaking (OIR). This will permit us to most efficiently take advantage of the current work and continue the RPS program efforts of utilities, parties and the Commission toward reaching the goal of 20% of retail sales generated by renewable resources no later than 2010. This proceeding is closed.

II. Procedural History

Senate Bill 1078, effective January 1, 2003, established the RPS program.[1] Decision (D.) 03-06-017, the first of several decisions implementing the program as part of R.01-01-024, set initial parameters and requirements. These included: (a) a process for determining the market price of electricity, (b) criteria for the rank ordering and selection of Least Cost/Best Fit (LCBF) renewable resources, (c) flexible compliance rules, and (d) an approach to forming standard contract terms and conditions.

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[1] Stats. 202, Ch. 516, S3, codified as Pub. Util. Code §§ 399.11, et seq. All subsequent code section references are to the Public Utilities Code unless noted otherwise.

We opened this proceeding, R.04-04-026, in April 2004 to continue implementation of the RPS program. In D.04-06-014, we adopted limited standard terms and conditions for RFOs, and directed compliance filings for both Plans and RFOs. We also provisionally approved each IOU issuing an RFO for the 2004 RPS program solicitations.

In D.05-07-039, we conditionally approved the Plans and RFOs for the 2005 solicitations. In D.05-10-014, we conditionally approved the long-term RPS procurement plans of each IOU, directed the filing of a supplement to each IOU's long-term plan, and ordered that review of future long-term plans be conducted in R.04-04-003 or its successor proceeding. We also noted that the Assigned Commissioner and assigned Administrative Law Judge (ALJ) should set a schedule for the consideration of 2006 draft Plans and RFOs. By Assigned Commissioner and ALJ Ruling dated November 19, 2005, the IOUs were directed to submit their 2006 RPS Plans and draft RFOs.

On December 7, 2005, PG&E, SCE and SDG&E filed supplements to their respective 2005 long-term Plans. On December 22, 2005, PG&E, SCE and SDG&E filed the annual RPS Plans for 2006 and draft RFOs. On January 17, 2006, the following parties filed comments on the 2006 Plans: PG&E, the Commission's Division of Ratepayer Advocates (DRA), Aglet, Green Power Institute (GPI), and Union of Concerned Scientists (UCS). On January 31, 2006, the following parties filed reply comments: PG&E, SCE, SDG&E, DRA, Aglet, UCS and Alliance for Retail Energy Markets (AReM).

Regarding the benchmarking methodology, on January 10, 2006, SCE filed updated TOD factors for its 2006 solicitation, as ordered in D.05-12-042. On January 17, 2006, PG&E, SCE and SDG&E filed proposals for benchmarking TOD profiles. On February 8, 2006, PG&E filed a supplement to its 2006 solicitation protocol and TOD benchmarking proposal. Also on February 8, 2006, SCE filed a supplement to its benchmarking proposal. On February 15, 2006, DRA, Aglet, GPI, and Solel Inc. (Solel) filed comments. On March 1, 2006, PG&E, SCE and SDG&E filed reply comments.

This decision addresses the most recently proposed RPS Plans, including RFOs. We also address issues that arise from parties' proposals and comments on a TOD benchmarking methodology.

III. Overview of RPS Program and 2006 Plans

Pursuant to the RPS legislation, each electrical corporation is required each calendar year to procure, with some exceptions, a minimum quantity of electricity from eligible renewable energy resources as a percentage of total retail sales. (§ 399.15(a).) This is generally known as the annual procurement target, or APT. Each electrical corporation is also required, with some exceptions, to increase its total procurement from eligible renewable energy resources by at least 1% of retail sales per year until it reaches 20%. (§ 399.15(b)(1).) This is generally known as the incremental procurement target, or IPT.

To fulfill these requirements, each electrical corporation must prepare a renewable energy procurement plan. (§ 399.14(a).) The Plan must include, but is not limited to, (a) an assessment of demand and supply to determine the optimal mix of renewable resources, (b) use of compliance flexibility mechanisms established by the Commission, and (c) a bid solicitation. (§ 399.14(a)((3).) The Commission must review and accept, modify or reject each electrical corporation's Plan prior to the commencement of renewable resource procurement. (§ 399.14(b).)

Pursuant to ruling dated November 19, 2005, each IOU submitted its most current (2006) Plan on December 22, 2005. Each Plan describes the actions the

IOU will undertake in order to meet its 2006 APT and IPT as it proceeds to ultimately procure 20% of its retail sales from eligible renewable resources by 2010. Each Plan includes resource planning information and a master purchase and sale agreement or RFO. The Plans are briefly described below.

A. PG&E

PG&E estimates its 2006 APT is about 10,942 gigawatt-hours (gWh), and its IPT is approximately 700 gWh.[2] In its 2006 Solicitation, PG&E seeks to procure approximately 1% to 2% of its retail sales volume, or between approximately 700 and 1,400 gWhs per year.

PG&E states that, starting in 2007, it will require more capacity to meet its reserve margin requirements, as well as additional peaking energy resources to meet its net energy requirements. After 2007, PG&E says it will require additional dispatchable peaking and shaping resources to meet energy and capacity requirements for all subperiods. PG&E reports that, based on the Commission's flexible compliance rules, projects that offer deliveries with an on-line date no later than the start of 2008 are of particular interest to PG&E.

PG&E's proposed 2006 Plan and draft master purchase and sale agreements are similar to those in 2005. PG&E seeks Power Purchase Agreements (PPAs) with delivery terms of 10, 15 or 20 years beginning in 2006 or beyond. Participants may also propose delivery terms between 10 and 20 years. Participants may submit offers for four specific products: (a) as-available, (b) baseload, (c) peaking, or (d) dispatchable. PG&E states that it will also

[2] This is an APT of about 1,561 average megawatts (aMW) at an 80% capacity factor (CF). This is an IPT of about 101 aMW at an 80% CF.

consider two types of combination products: (a) peaking and as-available, or (b) peaking plus other firm deliveries in any combination of other TOD periods.

In addition to purchases, PG&E will also consider two ownership alternatives: (a) power purchase agreement with PG&E buyout option (in which the developer gives PG&E the option to purchase the facility at a pre-determined price after it has been in operation for a certain number of years), and (b) turnkey agreement (in which the developer sells the project to PG&E for a pre-determined price at the time the project enters commercial operation). PG&E states that it will evaluate offers using the following considerations: (a) market valuation, (b) portfolio fit, (c) non-price factors, (d) adjustment for transmission adders and integration costs, and (e) other non-price considerations.

PG&E assumes a status quo regulatory environment as the context for its 2006 Plan. PG&E identifies four differences between its 2005 and 2006 proposed solicitations:

1. In 2006, bidders will have more time after PG&E issues its solicitation in which to submit bids.

2. While the evaluation criteria remain the same as in the 2005 solicitation, the quantitative weightings have been eliminated to provide more flexibility and accommodate the wide range of technologies and specific project circumstances.

3. The resource needs section has been updated to reflect updated assessment of portfolio needs.

4. In 2006, PG&E proposes to accept bids from all eligible renewable resources, resulting in the acceptance of bids with delivery points anywhere in California, in addition to the CAISO delivery points authorized in D.05-07-039.

B. SCE

SCE estimates its APT for 2006 is 14,220 gWh, and its IPT for 2006 is 754 gWh.[3] SCE states that it has a near-term need for renewable energy during the time period beginning January 1, 2006 and ending on December 31, 2008, and, therefore, its evaluation criteria will favor proposals which include these initial operation dates. SCE states it also has long-term needs for renewable energy and will consider proposals which are based upon initial operation dates after December 31, 2008, but it will not consider any proposals based upon an initial operation date after January 1, 2013.

SCE's 2006 Plan and RFO are similar to those in 2005.[4] SCE states that its 2006 RPS Plan is straightforward: after SCE completes its 2005 procurement, SCE intends in 2006 to contract for the balance of renewable power necessary to achieve 20% renewables by 2010. SCE indicates that it does not have an institutional preference for a particular resource mix or technology type. SCE's affiliates are permitted to submit a bid.[5]

Many variables affect SCE's procurement needs, according to SCE, including a projection of bundled sales, the amount of load in SCE's service territory served by direct access providers, and the anticipated level of output from baseline contracts. As a result, SCE develops high, base and low

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[3] This is an APT of about 2,029 aMW at an 80% CF. It is an IPT of about 108 aMW at an 80% CF.

[4] In fact, SCE states that it intends to issue an RFO in 2006 that is substantially identical to its 2005 RFO. SCE did not file a new draft RFO with its 2006 Plan.

[5] Because SCE affiliates may participate, SCE reports that it has engaged an independent evaluator to monitor the process. SCE will discontinue the engagement of the independent evaluator if SCE does not receive a proposal from an SCE affiliate.

procurement need scenarios. In order to maximize its compliance prospects, SCE states that it plans to procure for the high procurement needs scenario. If SCE successfully procures to its high procurement needs scenario in 2010, and the high procurement needs scenario actually occurs, SCE estimates it will achieve a 20% level of renewables in 2010. SCE estimates it will be above 20% in 2010 if either the base or low case procurement needs scenario actually occurs.

SCE allows sellers to offer contract terms of 10, 15 and 20 years, and requires each proposal to be at least 1 MW. For generating facilities located in SCE's service territory, SCE says the only acceptable delivery point is CAISO Zone SP-15. For generating facilities located outside SCE's service territory, SCE says it will consider proposals with a delivery point outside of CAISO Zone SP-15, but that the delivery point must be within the CAISO control area.

According to SCE, it will evaluate proposals based on criteria intended to achieve the lowest ratepayer cost and the best fit with utility retained generation and California Department of Water Resources generation. SCE says it takes into account the criteria in the Commission's LCBF decision, D.04-07-029. Specifically, SCE states it will employ a production simulation model to calculate total system production costs and benefits associated with the renewable generating facility, incorporating Effective Load Carrying Capacity values, transmission costs, and integration costs and benefits. This will produce a benefit/cost ratio for each proposal. In addition, SCE will consider, among other things, debt equivalence, credit, and seller qualifications. Finally, SCE says it will utilize attributes identified by the Commission as quantitative methods for evaluating tie-breakers.

C. SDG&E

SDG&E states that its 2006 APT is 741 gWh.[6] SDG&E does not identify the amount of its 2006 IPT. SDG&E says it expects to exceed both its 2006 APT and IPT, and will bank APT surpluses for future compliance.

While SDG&E says it continues to move aggressively toward the 20% by 2010 goal, it is considering whether or not to issue an RFO in 2006. SDG&E anticipates making this decision after it concludes negotiations with bidders from its 2005 solicitation. SDG&E reports that, to the extent necessary, SDG&E will avail itself of the flexibility permitted in the RPS program including the ability to (a) sign bilateral agreements, (b) bank purchases in excess of the APT, and (c) borrow from the bank to make up shortfalls. SDG&E anticipates that it may seek approval of bilateral contracts.

If SDG&E seeks additional offers, SDG&E says it intends to issue one RFO. According to SDG&E, that RFO will solicit PPAs and/or ownership options from developers of all renewable technologies that can interconnect with the CAISO or are located in the Imperial Valley. SDG&E says products may include unit firm or as-available deliveries starting in 2007, 2008, 2009 or 2010. SDG&E's draft RFO allows sellers to offer renewable products anywhere in the CAISO grid or in the Imperial Valley, but SDG&E says it continues to have a preference for in-basin renewable resources, particularly those that can offer overall reliability, must run reliability, or resource adequacy benefits.

SDG&E says that bids will be initially ranked based on the all-in bid price and transmission costs. SDG&E's draft RFO states that three components

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[6] This is an APT of about 106 aMW at an 80% CF.

of the LCBF that are of primary importance to SDG&E are: (a) delivered energy costs, (b) overall fit with SDG&E's resource portfolio, and (c) transmission system upgrade costs. SDG&E says it will differentiate offers of similar cost by reviewing qualitative factors including location, benefits to minority and low income areas, resource diversity, and environmental stewardship. It will also differentiate offers of similar cost by reviewing other factors (e.g., delivery reliability, ability to advance schedule, technology, likelihood project will be able to develop and achieve commercial operation within established time frames, operational flexibility, development risk, financing plan, corporate capabilities, credit, proven experience, repowering, contract extension).

SDG&E seeks power purchase agreement proposals for 10, 15 or 20 years, but will consider other contract durations subject to Commission approval. Resources located in Imperial Valley must commence no earlier than July 2010, unless the resource has adequate transmission capability to deliver to the CAISO control area. Resources from Imperial Valley without adequate transmission capability shall be contingent upon SDG&E obtaining approval for, and being able to license and construct, a new 500 kilovolt (kV) line from Imperial Valley to the San Diego area, according to SDG&E.

SDG&E also seeks PPA proposals with either a buyout option or a turnkey acquisition. SDG&E also says it intends to append a copy of the Edison Electric Institute (EEI) Agreement to the RFO, and reserves the right to revise both the RFO and EEI Agreement prior to issuance. Finally, SDG&E's draft RFO states that all offers in response to its RFO shall be evaluated together with offers in response to SDG&E's distributed renewable technologies solicitation, and one short list will be created.

IV. Issues Common to All Plans

We have, in fulfilling our duties and allowing electrical corporations to fulfill theirs, granted electrical corporations considerable flexibility in the way they satisfy RPS program goals. In this context, we have provided guidance, and adopted limited and specific program requirements. We have also taken steps to broaden and enhance the quality of RPS bids and improve the contracting process. Further, we have employed the presumption that utilities are able to use their business judgment in running their solicitations, unless their plans threaten to impair the effectiveness of the RPS program. (D.05-07-039, page 15.)

We continue to do so here. We also provide additional guidance, take limited actions to further expand opportunities, and adopt a schedule to organize the process for 2006. We encourage IOUs to make modifications regarding, and we set boundaries on, certain interactions to neutralize the transaction (i.e., level the field) between parties in order to avoid impairing the effectiveness of the program.

We do this based on comments from IOUs and parties that raise several concerns. These concerns include whether or not additional compliance flexibility should be permitted now, because IOUs foresee potential difficulties about reaching 20% of deliveries by 2010. Concerns have also surfaced about whether or not there is room for discrimination in selection of bidders for the short list, and, as a result, whether there should be increased disclosure of evaluation and selection methods. In fact, as SDG&E says:

> "It is plain, however, that despite the measurable progress made to date by the parties involved in the implementation of the RPS program, significant obstacles to the success of the program continue to exist." (Reply Comments, page 2.)

We address below the important obstacles and issues raised by parties. We do so in the context of reaffirming that each electrical corporation ultimately has the duty to take all reasonable actions to meet the state's RPS goals. Our responsibility includes reviewing the results of solicitations, and accepting or rejecting proposed contracts submitted for approval, based on consistency with approved Plans. (§ 399.14(c).) The Plans approved herein will be a fundamental, but not necessarily the only, part of that review, as described further below.

Moreover, while we review each Plan, our conditional acceptance is based on the fact that we have neither written each Plan, dictated with precise detail the specific language on each page of each Plan, nor do we take over procurement. These remain IOU Plans, subject to our guidance along with limited, focused and specific direction. Further, the procurement duties remain those of each IOU. The IOU is ultimately responsible for proposing and obtaining approval of reasonable Plans, and achieving successful procurement under the RPS Program.

A. Transmission

1. Deliveries Anywhere in California

PG&E's Plan includes a proposal to accept bids from all eligible resources, as defined by the CEC, with delivery points anywhere in California. This would be in addition to the CAISO delivery points authorized by D.05-07-039. Aglet agrees, saying:

> "IOUs should be able to contract with renewable suppliers that propose delivery points anywhere in California. Public Utilities Code § 399.11(a) clearly states that the goal of the RPS is to attain 20 percent renewable energy for California, and not just for the CAISO control area. PG&E's proposal is consistent with that goal and

> deserves serious consideration by the Commission."
> (Aglet Comments, page 8.)

We approve PG&E's proposal for the reasons stated by Aglet. We were previously concerned about accurately tracking deliveries for RPS compliance. (D.05-07-039, page 33.) We understand that tracking issues are now resolved. This allows us to adopt PG&E's proposal for all three IOUs, to the extent any IOU does not now do so,[7] and will help California reach program goals by allowing IOUs to cast "a wider net for projects…" (D.05-07-039, page 10.)

PG&E also proposes to use "typical commercial arrangements" (i.e., remarketing, swaps, transmission adjustment bids) to permit PG&E to accept electricity at a CAISO delivery point and avoid the cost of congestion. (Plan, page 12.) GPI supports this proposal during transmission-constrained episodes. (GPI Comments, page 4.)

We encourage utilities to be creative and innovative in all reasonable ways in order to meet the RPS program goals, both during transmission-constrained and unconstrained times. It is ultimately up to the California Energy Commission (CEC), however, to design and implement an accounting system to verify compliance with the RPS by retail sellers. (§ 399.13(b).) In that context, we remind parties that only those deliveries verified by the CEC in its procurement verification report may be counted toward a utility's RPS requirements. If parties and the CEC develop a verification method that does not apply to a specific contract signed by a utility, or the CEC is unable to verify claimed

[7] SDG&E says it currently accepts offers from projects anywhere in California.

generation from a particular contract, we will not allow that generation to be counted toward the IOU's RPS obligations. Our authorization for IOUs to seek contracts throughout California is not a substitute for actual verification of procurement by the CEC.

2. Cost

Transmission issues are recognized as presenting potential impediments to achieving RPS goals. We have been examining these issues here and in other proceedings (e.g., Investigation (I.) 00-11-001), and have recently opened a new proceeding to continue that work (I.05-09-005). GPI makes a recommendation in its comments on the 2006 RPS Plans here, however, that we think deserves consideration, since it may increase flexibility and facilitate achieving RPS goals.

GPI asserts that the considerable discussion about transmission (e.g., need, location, cost, cost recovery) has not yet considered an important issue in the larger discussion. That issue is gross versus net cost for RPS-related transmission.

According to GPI, renewable energy will either displace energy from existing plants or new plants. Displacing energy from those plants affects the transmission system. Future transmission needs are different for RPS scenarios versus non-RPS scenarios, but the choice is not between RPS and doing nothing. Rather,

> "The choice is between making the transmission improvements needed for 20% renewables, and making the transmission improvements needed for any non-RPS alternative scenario with the same demographics. Looking at the net, rather than the gross, transmission requirements for renewables may alter perspectives on cost allocation issues." (GPI comments, page 3.)

No reply comments oppose GPI's suggestion, and DRA states its support:

> "DRA maintains that this transmission-system issue calls for reevaluating the IOUs practice of making the costs of all transmission upgrades necessary for the interconnection of renewable resources part of the costs of those renewable resources. A more comprehensive cost allocation, including the cost of transmission for conventional resources, should be used to put the costs of transmission upgrades for renewable resources in proper perspective." (DRA Reply Comments, pages 2-3.)

We agree that these costs must be viewed in the proper perspective. Determining the cost to attribute to a project depends upon what one considers to be the alternative. If demand for electricity grows, for example, and we assume that demand is met with something other than blackouts, then some alternative makes that electricity available. Whatever the alternative, it has implications with respect to the physical transmission system. It also has implications for cost allocation related to cost recovery, and cost allocation as it may relate to project ranking.

The LCBF methodology requires that projects be ranked on a total cost basis, and that total costs include "indirect costs associated with needed transmission investments…" (§ 399.14(2)(B).) In doing this, however, we have already recognized that it may be reasonable to adjust transmission costs for their net cost:

> "Adjustments may also be appropriate if, for example, renewable generation is expected to replace planned non-renewable energy flows in a manner that reduces the need for transmission upgrades. [Footnote deleted.] We will revisit the continued reasonableness of the adopted Transmission Ranking Cost Report and bid evaluation

> methodologies in future years. We will continue to make improvements as appropriate…" (D.05-07-040, pages 7-8.)

One potential improvement is for IOUs to subtract transmission costs related to a non-RPS scenario from those related to an RPS scenario on a system-wide basis to determine the net costs that should be used for the LCBF analysis. This might be done in large increments of RPS versus non-RPS facilities. The result might be that IOUs and their ratepayers are responsible for the cost of the "backbone" transmission system, with RPS generators responsible in the LCBF ranking analysis only for their reasonable costs of interconnection to the grid (e.g., generation tie lines). This may or may not be consistent with the way an IOU would present cost assessment for a new utility powerplant. That is, "indirect" costs related to a new utility plant would not necessarily include the cost of all secondary and downstream changes to the transmission system, only those to interconnect the new plant to the transmission "backbone." As a result, going forward, the LCBF analysis might reflect the "indirect costs associated with needed transmission investments transmission costs" on a net, not gross, basis.

Parties should continue to present concerns and solutions. Further recommendations on this issue, if any, should be supported with example calculations and information on how such methods would work. Neither GPI nor DRA, however, present a sufficiently developed recommendation here for our adoption.[8]

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[8] GPI asks that this issue be addressed in R.05-09-005. To do so, GPI should make specific proposals there, to the extent consistent with the issues and schedule in the Assigned Commissioner's Scoping Memo for that proceeding.

3. Projects

We are required to direct electrical corporations to prepare RPS Plans. We must review and accept, modify or reject those Plans. We must review the results of an RPS solicitation submitted for approval and accept or reject proposed contracts based on consistency with the approved Plan. Finally, we are directed to exercise our authority to require compliance with our RPS Plan orders. (§ 399.14(a), (b), (c) and (d).)

In this context, we note parties express considerable concern regarding whether or not transmission will be available to permit compliance with the requirement that 20% of retail sales be obtained from renewable resources by 2010. We are considering this matter in several places, as noted above.

We also point out here, however, that electrical corporations must bring us their concerns and problems along with reasonable proposed solutions in time for us to respond and allow this program to succeed. In a future determination of an electrical corporation's compliance with an RPS Plan and program requirements, we will consider the extent to which the electrical corporation brought a problem to us on a timely basis, and proposed a reasonable and realistic solution. We will not be sympathetic to granting waivers or reducing penalties due to lack of transmission, for example, without the electrical corporation demonstrating that it took all reasonable action to bring the problem to our attention timely, presented realistic solutions, filed applications timely for necessary projects, and took any and all other actions that could reasonably have been expected to address, if not solve, the problem.

B. Compliance

1. IPT of 1.2%

Parties were asked to discuss whether or not the Commission should adopt an IPT greater than the 1% increment required by statute. An IPT of 1.2%, for example, would create a margin of safety toward meeting the 2010 RPS goal of 20%, thereby planning against various risks, including project or contract failure. IOUs oppose this requirement, while it is supported by DRA.

We decline to adopt an IPT of 1.2%, or other specific margin of safety. The IOUs are already engaged in contingency planning. Their contingency planning may or may not ultimately be adequate, but it appears sufficient at this time.

For example, PG&E reports that it seeks to acquire incremental procurement in 2006 of between 1% and 2% of its retail sales volume (between 700 gWh and 1,400 gWh per year). (PG&E Solicitation Protocol, December 22, 2005, page 2.) PG&E says that it intends to include a margin of safety in its procurement. (Reply Comments, page 2.) SCE shows that it is planning to achieve 20% renewables generation as a percentage of bundled sales under the high procurement requirement scenario by 2010. This means that SCE will have in excess of 20% if the base or low procurement scenarios materialize. (SCE Plan, December 22, 2005, page 10.) SDG&E declares that it has adopted a strategy of achieving 24% of its bundled customer retail load served by renewable generation by 2010. (Supplement to Long-Term Procurement Plan, December 6, 2005, page 17.)

There are enough other program issues and details that we do not wish to potentially further complicate the program by adopting either an increased IPT or other margin of safety requirement (along with the possibility of other penalty measures and methods for compliance flexibility). Rather, as SDG&E says "the resources of the Commission and the other parties …are better put to use in removing the *existing* roadblocks to the program's success…" (Reply Comments, page 4, emphasis in original.) We agree, given that each IOU already includes a margin of safety in its Plan. IOUs must now meet APT and IPT requirements, or face penalties. IOUs and parties should focus their resources on making the program successful each year at those levels, and by 2010, without Commission-adopted increased incremental goals.

Importantly, IOUs understand that they are ultimately responsible for program success each year and by 2010. For example, SCE says: "SCE is ultimately required to meet its RPS obligations or possibly suffer penalties…" (Reply Comments, page 5.) SCE also says: "SCE is responsible for achieving its RPS procurement obligations…" (Reply Comments, page 9.) SDG&E says: "The utilities are already required to meet incremental procurement targets ("IPTs"), annual procurement targets ("APTs") and the overall 20% target." (Reply Comments, page 4.) PG&E notes that "the Commission has sufficient incentives in place to encourage PG&E to meet its RPS targets, including the consequences for non-compliance discussed in D.03-06-071." (Reply Comments, page 3.)

The RPS Procurement Plans we have adopted before, and adopt here, provide sufficient opportunity for each IOU to succeed. We decline to adopt a larger IPT or other margin of safety. But, we remind IOUs that we are required to enforce our orders if an electrical corporation fails to comply. (§ 399.14(d).) We have every intention of doing so, and encourage all electrical corporations to undertake all reasonable actions to make the RPS program a success.

For example, seller non-performance may be an excuse for an IOU's failure to meet an IPT or APT.[9] If an IOU uses seller non-performance as an excuse, however, that IOU must also show that it took all reasonable actions to vigorously pursue necessary IPT and APT goals. This may include an IOU setting and reasonably pursuing its own margins of safety. While we do not adopt an IPT of 1.2%, in exchange we expect an IOU, in any non-compliance defense, to show its plan included a reasonable margin of safety, or it took other reasonable actions, to satisfy its RPS targets.

We will also require a modest amount of additional reporting in exchange for not adopting increased margin of safety targets. Specifically, we direct each IOU to provide us with information on whether each approved RPS project (for which a PPA has been executed between the generator and the IOU, and approved by the Commission) is on target with the project's milestones and projected initial operation date. This information shall be provided with each compliance report (currently due March 1 and August 1 of each year; see D.05-07-039, Ordering Paragraph 17). Energy Division may work with the IOUs to determine an acceptable reporting format.[10] Each utility should also make the report available to the fullest extent possible to those on the service list, and any

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[9] See D.03-06-071, page 50. Seller non-performance includes contract default, force majeure, terminations, and project development delays, assuming non-performance is due to factors beyond the control of the utility. No IOU excuse is permitted if the IOU was responsible for the seller's non-performance.

[10] Among other things, we may use this to help assess whether an IOU had (or should have had) reasonable expectation or knowledge of upcoming non-compliance, and should have taken more aggressive action in order to avoid potentially being liable for a non-compliance penalty. Each IOU should notify Energy Division when a major milestone is missed.

other person or party expressing interest, subject to confidential treatment of protected information.

2. Full Earmarking and Flexible Compliance in 2010

PG&E and SCE believe the flexible compliance rules need to be modified to allow for full earmarking now, and flexible compliance in 2010. We decline to do so. We encourage IOUs to redouble their efforts to make this program a success no later than 2010, rather than focus limited time and energy of parties and the Commission on modifying the program so IOUs do not later face the potential for penalties. We may or may not give the full earmarking proposal further consideration in the upcoming decision on reporting but, for the reasons explained below, we decline to adopt it here. As we said last year, and repeat here, we consider 2010 the year by which 20% of energy sold to retail end-users is to be delivered from eligible renewable resources. The utilities should too.

a) Background

The RPS legislation required that we adopt:

> "Flexible 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." (§ 399.14(a)(2)(C).)

We adopted initial flexible compliance rules in 2003. (D.03-06-071, pages 40-55.) In doing so, we rejected a California Wind Energy Association (CalWEA) proposal that we characterized as "too rigid" (which included only a three-month extension to make up a deficit). We also rejected a PG&E and SCE proposal that we characterized as the "other extreme" (which included permitting deferral of the entire procurement obligation up to three years with no review or penalties). We adopted a middle ground recommended by The Utility Reform Network (TURN) and SDG&E, the primary elements of which are:

- An IOU must meet 75% of its procurement target each year (with limited exceptions)

- An IOU may carry forward a deficit of up to 25% without explanation for up to three years, but must satisfy the deficit within the three-year period

- A present year procurement target must be met before applying procurement to previous years' deficits

- Annual shortfalls in excess of 25% are permitted upon a demonstration of one of four conditions:
    - Insufficient response to an RFO
    - Contracts already executed will provide future deliveries sufficient to satisfy current year deficits
    - Inadequate public goods funds to cover above-market renewable contract costs
    - Seller non-performance (including contract defaults and conditions beyond the control of the utility).

- An IOU is subject to a non-compliance penalty of $0.05 per kilowatt-hour (kWh), with an overall cap at $25 million

As we explained in 2003, these rules permit an IOU reasonable flexibility in meeting its procurement targets, but do not allow it to get so far behind as to jeopardize its ability to make up deficits, jeopardize its ability to meet the overall RPS goals, or compromise any future RFOs. They allow an IOU to engage in good faith efforts to maximize ratepayer benefits and promote orderly renewable resource development, without unnecessarily frustrating RPS program objectives. The penalties provide incentives and clear consequences, establish concrete and transparent rules, and remove uncertainty. Recognizing the program was new, we granted each utility an exemption for the first year. We also found that compliance requirements are not triggered until an IOU is creditworthy.

In 2005, we adopted a PG&E recommendation to modify the flexible compliance rules. This modification permits a utility, in response to a shortfall greater than 25% for a particular year, to demonstrate in its annual compliance filing that contracts already executed will provide incremental future deliveries sufficient to satisfy the current year's deficit. If able to make that demonstration, the utility is permitted to "earmark" the future deliveries to apply first to the portion of the deficit that exceeds 25% in the year of the deficit, rather than to the year of contract delivery, so long as no deficit is carried forward more than three years. (D.05-07-039, Ordering Paragraph 14.)

b) Proposal

PG&E and SCE now propose "full earmarking," wherein deliveries from earmarked contracts may satisfy any portion of a prior year's deficit, not just the portion that exceeds 25%.[11] PG&E and SCE also propose that flexible compliance rules apply in 2010.

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[11] PG&E says that certain references to APT should be to IPT, citing D.04-06-014, Appendix B, page B-2 in support. (PG&E Comments, page 2, footnote 2.) As a result, PG&E explains that its comments refer to IPT, not APT. We understand the proposal here to be with respect to IPT. We expect to address the treatment of APT and IPT, as used for reporting and flexible compliance, in a decision in the near future and there

Footnote continued on next page

c) Discussion

We agree with GPI and DRA that the full earmarking proposal is an effort to roll back the 2010 RPS date, if not all the way back to 2017, then back to somewhere between 2010 and 2017. In combination with flexible compliance for 2010, it pushes the compliance date back to at least 2013.

We rejected such proposals in 2003, and again in 2005, because we wanted to prevent continuous roll-over of the 25% shortfall. Continuous roll-over may permit a utility to fall so far behind in its RPS procurement that it jeopardizes attainment of the program's goals. (D.05-07-039, page 13, citing D.03-06-071, page 49.)

Lack of Evidence: IOUs contend that their procurement decisions now may be affected by our decision regarding earmarking, and may affect the cost of the program. We are not persuaded. No evidence supports this assertion. For example, there is no evidence that the market price referent (MPR) next year will be more than it is this year. There is no evidence that procuring more now compared to later will increase the overall cost of the program at all, or if so, how much. Nor is there evidence that this cost, if any, is greater than the benefits of the renewables program, or greater than the incremental benefits of obtaining program goals sooner.

For example, assume more is procured in 2006 due to our decision to deny full earmarking and flexibility in 2010 compared to the amount procured in 2006 if we allow full earmarking and increased flexibility. Also assume that increased procurement now results in IOUs not being able to

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reconcile confusion, if any. We do not need to address the APT and IPT distinction here, however, to dispose of the proposal.

negotiate as low a price from an RPS generator as would be the case otherwise. There is no evidence, even given these assumptions, that this sum, if any, is substantial. Moreover, there is no evidence how this sum, if any, compares to the benefits already found by the state of attaining 20% renewables or attaining the benefits earlier. Rather, it is California state policy to attain 20% renewables "for the purposes of increasing diversity, reliability, public health and environmental benefits." (§ 399.11(a).) The decision to attain 20% renewables has already balanced various direct and indirect costs, and determined the benefits justify the target. This policy decision is already constrained by the Market Price Referent (MPR) and the state's willingness to use Supplemental Energy Payments (SEPs), if any. Even if there is a cost to rejecting the recommendation of PG&E and SCE, which we are not convinced there is, we are not persuaded that it is material, that it is greater than the benefits of the program, or that it is greater than the incremental benefits of obtaining program goals sooner.

We also note that, while reporting and compliance are important, we do no want stakeholders to become diverted from the larger picture: 20% no later than 2010. The success of this program will largely be determined by the fundamental economics (e.g., level of RPS generator costs compared to MPRs and the availability of SEPs, if necessary). It will also fundamentally be driven by the vigor and commitment of each electrical corporation to the program's success. We agree with SDG&E when it "asks that all parties remain focused on identifying reasonable and practical implementation strategies that will ensure the best outcome for California." (Reply Comments, page 2.) Parties need to focus on strategies for success.

Future Defenses: Electrical corporations, including IOUs, will have a full opportunity later, if needed, to defend themselves against penalties.

That may be a complete defense, and may or may not include showing (a) insufficient response to RFOs, (b) inadequate SEPs to fund above-market costs, (c) seller non-performance independent of IOU's actions, or (d) other reasons.

As we have said before, it is our clear desire never to visit these penalties. IOUs may procure more renewables than the minimum required amounts. The best way to prove parties wrong who believe IOUs are unreasonably resisting this program is for the IOUs voluntarily to procure more than the bare legal requirements, within the MPR and SEPs. (D.03-06-071, pages 52 and 55.) And we repeat: "the utilities' focus should now be on seeking and signing the best possible contracts for renewable energy, rather than on seeking adjustments to compliance standards." (D.05-07-039, page 12.)

Policy of the State: Even if we wanted to adopt full earmarking and flexible compliance now—which we do not—the 20% by 2010 action item is the policy of the state, not just the Commission. That is, this action item was adopted jointly in Energy Action Plan II (EAP II) by the CEC and the Commission, not just the Commission. It was developed with the active participation of California's agencies having energy-related responsibilities, including, but not limited to, the Business, Transportation, and Housing Agency; the Resources Agency; the State and Consumer Services Agency; the CAISO; and the California Environmental Protection Agency (EPA). It was a coordinated implementation of energy policy articulated by the Governor through Executive Orders and instructions to agencies. It implements legislative direction. We decline to unilaterally act in conflict with EAP II, absent further consultation with those involved in EAP II development and adoption. Rather, we are bound by the commitments we agreed to therein, and will not modify them on our own at this time.

Further Evidence: On May 15, 2006, PG&E moved to file a supplement to its reporting and compliance comments. PG&E states that its supplemental comments (including a confidential appendix) provide evidence from its 2005 solicitation to support its full earmarking recommendation. We have given careful consideration to PG&E's further evidence and argument. We are not persuaded by any data, information or assertion therein.

PG&E asserts that "full earmarking will result in customer savings…and avoid sending inappropriate signals to the renewables market." (May 15, 2006 Supplemental Comments, page 1.) According to PG&E, the savings will be "hundreds of millions in costs." (*Id.*)

To the contrary, program prices payable by PG&E and its customers are already basically constrained to levels no higher than the MPR. Prices above the MPR are typically subject to recovery via SEPs, at no direct cost to PG&E ratepayers. The use of the public's money (e.g., via SEPs) should be left to those public officials authorized to make such decisions. By seeking full earmarking now, PG&E effectively seeks to prevent the Commission from making LCBF decisions, and the CEC from making decisions about the use of SEPs.

That is, RPS contracts are dependent upon Commission approval, with CEC approval of SEPs, if required. If PG&E decides to seek approval (via an advice letter submitted to the Commission) of a contract at a price above MPR, it is reasonable to let the process work itself out. The Commission may or may not approve the contract based on a full range of LCBF or other criteria. If approved by the Commission at a price above MPR but subject to recovery of SEPs, it is reasonable to let the CEC consider the use of SEPs. California citizens may desire the project now, for example, with earlier reduction in greenhouse gases (GHG) compared to another project later with delayed reduction in GHG. That is a weighing and balancing for the CEC to make on behalf of California's citizens based on the availability of SEP funds, and all the evidence and argument that will be presented to the CEC.

Every party, including PG&E, is legitimately concerned about LCBF and total RPS program cost. We are also concerned with meeting all other RPS program purposes and objectives (e.g., resource diversity, reliability, public health, environmental benefits, stable prices, economic development, new employment, reduction in reliance on imported fuels; see § 399.11(a) and (b)). Nonetheless, PG&E's cost concern, as it is reflected in its full earmarking recommendation, is misplaced. It seeks to have decisions made now that need not yet be made until all facts are known, and all competing purposes and objectives are weighed. It also takes decision-making away from the Commission and the CEC, including the balancing of competing public purposes and objectives that will properly be undertaken by each agency.

PG&E is also concerned that rejecting full earmarking now unreasonably gives a preference to projects with shorter lead times over those which might which take longer to develop. PG&E asserts that projects with longer lead times "should not be disadvantaged prematurely." (May 15, 2006 Supplemental Comments, page 3.) To the contrary, this is again a decision to be made by the Commission in its assessment of LCBF and other factors, and the CEC in its application of SEP funds.

Another potential concern with disallowing full earmarking now could be that it will artificially increase demand in the near term. This in turn might cause higher prices from bidders, sending "inappropriate signals" to the market, and result in the signing of more contracts now at higher prices than would otherwise occur (thereby incurring extra "hundreds of millions in costs"). To the contrary, there is a mechanism for relief from higher prices due to a lack of effective competition. (§ 399.14(c).) That is, if the entire supply curve shifts due to lack of effective competition, the Commission may order that contracts be renegotiated, or a new solicitation be conducted. In contrast, moving up or down the supply curve does not itself cause inappropriate price signals or excess costs. Rather, movement along the supply curve may be the normal result of policy decisions that California's public officials should make after weighing all competing interests, with the benefit of all the facts, once presented. Moreover, PG&E and its customers are largely, if not completely, protected as described above by approved contracts being at or below MPR, with costs above MPR generally recoverable via SEPs.

Finally, PG&E's cost concern might actually be a concern about penalty exposure absent full earmarking, since the absence of full earmarking may make it difficult to otherwise reach various procurement targets, according to PG&E. To the contrary, PG&E may, if penalties become an issue, state all necessary defenses at the appropriate time. Those defenses may include, for example, that reasonably priced bids were of insufficient quantity to meet targets, or that bidders were unable to offer sufficient supply within the required year to meet targets. These or other defenses may or may not be sufficient, but will be fully considered at the appropriate time. It is premature to grant full earmarking now based on a concern that may or may not materialize. Rather, existing rules already reasonably balance many competing goals, needs and objectives (e.g., reasonable flexibility while not allowing a utility to get so far behind so as to jeopardize its ability to meet overall goals or compromise future RFOs). As a result, no changes are warranted at this time.

Request for Extension of 2005 Earmarking Deadline: In its May 15, 2006 pleading, PG&E also asks that the earmarking deadline for the 2005 solicitation be deferred from June 30, 2006 to September 30, 2006.[12] PG&E gives examples of issues that it asserts need to be resolved, and will make the June 30, 2006 deadline problematic. No party argues to the contrary. No other IOU asks for similar relief. PG&E's request is granted, but only for PG&E.

C. Utility Construction and Ownership

PG&E and SDG&E include utility ownership alternatives in their RFOs. In particular, each shows that a bidder may offer a turnkey agreement or a buyout option after a number of years. SCE does not mention turnkey or buyout options, but allows affiliates of SCE to bid.

We note, however, that neither PG&E, SCE nor SDG&E as a utility company includes any discussion in its Plan of the utility itself building, and then owning and operating, the renewable generation resource. We point out that procure "means that a utility may acquire the renewable output of electric generation facilities that it owns…" (§ 399.14(g).) Also, "[n]othing in this article [Article 16, the RPS statute] is intended to imply that the purchase of electricity from third parties in a wholesale transaction is the preferred method of fulfilling a retail seller's obligation to comply with this article." (*Id.*)

The law is clear. The utility may procure the renewable generation from itself. There is no preference for compliance through purchases from a third party, including affiliates or others.

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[12] The June 30, 2006 date is set in D.05-07-039, ordering paragraph 15.

The IOUs are apparently not contemplating the building of renewable generation at this time. We intend to enforce the 20% by 2010 requirement. In doing so, we will take into account whether or not each electrical corporation undertook all reasonable actions to comply. One of those actions is building, then owning and operating, the resource itself. Utility construction of generation resources, of course, must be fully consistent with all Commission procurement rules (e.g., all-source solicitations; see D.04-12-048). We do not here require utilities to build resources. We only observe that the option should be considered.

The burden is on the electrical corporation to comply with the RPS program, subject to certain compliance flexibility. Compliance must be met, subject to compliance flexibility and absent valid reasons otherwise. By adopting the amended Plans herein, we point out that the absence of discussion in the 2006 Plans about a utility building, owning and operating the renewable resource does not excuse an IOU from compliance on the basis that it did not build the plant itself, absent a valid reason otherwise.

Finally, we point out that a utility may build a renewable resource and, under appropriate circumstances, earn between 0.5% and 1.0% increased rate of return on that investment. (§ 454.3.) That is, the Legislature has authorized an increased incentive for utility ownership of renewable generation. We think IOUs should consider taking advantage of this law and, where reasonable and appropriate, we will authorize the increased rate of return.

D. Deposits and Collateral

For the reasons explained below, we encourage IOUs to reconsider various bid and deposit requirements. We will take the level of deposits into account should an electrical corporation later seek to avoid a non-compliance penalty.

1. Summary of IOU Requirements for Deposits and Collateral

IOUs have different approaches to deposits and collateral. For example, PG&E requires a bid deposit of $3 per kilowatt (kW) upon notice that the bidder qualifies for PG&E's short list. The bid deposit is refundable under most conditions. The bid deposit converts to Project Development Security upon execution of a PPA, and the amount increases to $20/kW. PG&E also requires Commercial Operation Security during the time of commercial operation, with the amount either fixed (e.g., 12 months of revenue for a 20-year contract) or fluctuating (e.g., replacement cost collateral).

SCE requires a Proposal Deposit of $25,000 upon the submission of a proposal. Seller must replace the Proposal Deposit with a Short List Deposit upon notice the bidder qualifies for the short list, but the Proposal Deposit is not returned until later (e.g., upon SCE's rejection of seller's proposal, or upon execution of a PPA; see SCE 2005 Procurement Protocol, page 11, Item 3.05(d)). The Short List Deposit is the greater of zero or net capacity times $3/kW less $25,000.[13] The Proposal Deposit and Short List Deposit are refundable under most conditions. Upon execution of a PPA, SCE requires seller to post Performance Assurance in the amount of $20/kW, which is held by SCE as a

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[13] The formula means that projects of 8,333 kW and smaller have a Short List Deposit of zero, and projects over 8,333 kW have an increasing deposit amount. For example, a 5 megawatt (MW) project would have a Project Deposit of $25,000 and a Short List Deposit of zero, for a total deposit of $25,000. A 10 MW project would have a Proposal Deposit of $25,000 and a Short List Deposit of $5,000, for a total deposit of $30,000.

Development Fee (to ensure seller maintains adequate progress in development of the project by the firm operation date). SCE also requires collateral during the operation of the project to cover a portion of SCE's exposure in the event that the market price for energy supplied to SCE by seller exceeds the energy price during the term of the PPA.

SDG&E's Plan states that SDG&E reserves the unilateral right to evaluate and determine the credit-worthiness of each bidder. Each bidder is required to complete an RFO credit application as part of the offer.[14] SDG&E requires that the credit support arrangements (e.g., letter of credit) be negotiated prior to an offer being accepted as a winning offer. SDG&E does not appear to have a specific Proposal Deposit, Bid Deposit, Short List Deposit, Project Development Security, Commercial Operation Security, or similar amounts, but SDG&E reserves the right to negotiate deposits and collateral as it believes necessary.

2. Bid Deposit

We addressed bid deposits in D.05-07-039. We noted there that, according to California Wind Energy Association (CalWEA) and Solargenix, a bid deposit could deter qualified bidders or harm negotiations. We also noted that, according to SCE, bid deposits could improve the quality of submitted bids. We determined we had insufficient information to choose between these hypotheses, would not interfere with the IOUs' judgment about the need (or lack

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[14] The credit application was not submitted with the 2006 Plan. Bidders are referred to an RFO website for the application. The website address, however, indicates it is "TBD." We understand this to be "To Be Determined."

thereof) for deposits for 2005, and urged parties to bring evidence of problems with bid deposits for 2005, if any, to our attention.

No party brings any new information to our attention. Aglet restates the position of CalWEA and Solargenix, and says it agrees. Aglet recommends a maximum bid deposit of $3/kW for SCE and SDG&E as used by PG&E.

Given the absence of specific new evidence, we decline to adopt Aglet's recommendation. Nonetheless, we make the following observation. PG&E does not require a bid deposit until a bidder is selected for the short list. In contrast, SCE requires a bidder to deposit $25,000 simply to submit a bid. While the deposit is refundable, that is a deposit of $25/kW for a 1 MW project. That seems to be an excessive amount, and an unreasonable requirement for a project simply to submit a bid.

SCE believes its approach improves the quality of bids, and may alleviate later financial losses should a project otherwise fail. DRA correctly points out, however, that this is a balance of risk between "margin of safety" (with avoidance of project failures) and facilitating the development of desirable projects. (DRA Comments, page 4.) To mitigate barriers to program success, we think the better balance is to have more projects, not less, submit bids for evaluation. In fact, SCE observes that:

> "the developers' views of what RPS-eligible renewable resources are likely to be available is at least as important, if not more important, than the utilities' views, because the developers are uniquely situated to know whether or not particular resources are worth developing and bidding into a utility solicitation." (Plan, December 22, 2005, page 18.)

We do not direct SCE to change its deposit amount or practice, but encourage SCE to reconsider and adopt a scheme more in line with that of PG&E: no Proposal Deposit, a Bid Deposit of $3/kW once the project is on the short list, and full refund of the deposit including interest under most conditions. We similarly decline to direct SDG&E to adopt any particular deposit amounts or practice, but also recommend that SDG&E employ equally reasonable criteria.

We will take the level of deposits into account should an electrical corporation later seek to avoid a non-compliance penalty. That is, if an electrical corporation later faces a non-compliance penalty but seeks reduction or waiver of that penalty, that corporation must make a showing that its deposit requirements were reasonable compared to those of PG&E, and that its deposit scheme did not prevent otherwise viable projects from coming forward at least for evaluation. We again urge parties to bring evidence of problems with bid deposits, if any, to our attention.

3. Other Collateral

We similarly make no orders regarding other collateral requirements of the IOUs (e.g., Project Development Security, Commercial Operation Security, Performance Assurance Deposits, Development Fees, other collateral). Nonetheless, just as with bid deposits, we might take the level of other collateral into account should an electrical corporation later seek to avoid a non-compliance penalty. We again urge parties to bring evidence of problems with collateral, if any, to our attention.

E. Resource Stacks

The LCBF Plan must include an assessment of portfolio supplies to determine the optimal mix of renewable resources with various deliverability characteristics. (§ 399.14(a)(3)(A).) In its discussion of supplies, PG&E's Plan addresses various resource types and the optimal mix based on PG&E's need. PG&E's Procurement Protocol states that, for turnkey proposals, it has a strong preference for small hydro and central station solar. At least some parties appear to have interpreted this as continued use of "resource stacks."

On the other hand, SCE states that:

> "…the development of a 'resource stack' of preferred or projected future renewable procurement has limited benefits…Moreover, given SCE's experience with recent solicitations, resource types cannot be definitely 'ranked;' therefore, a resource stack may be at odds with the least-cost/best-fit evaluation standards imposed by the RPS legislation. SCE also does not have an institutional preference for a particular resource mix or technology type, and the RPS legislation does not require any specific mix of technology types." (Plan, December 22, 2005, pages 18-19.)

We agree with SCE. We have noted the dangers of using resource stacks to pre-screen or discourage bids, and stated that we do not want resource stacks to act as hidden weighting factors in bid evaluations. (D.05-07-039, page 7.) In its reply comments, PG&E clarifies that "PG&E has previously explained that it would evaluate bids on a case by case basis, instead of using a resource stack to select its contacts." (Reply Comments, page 12.) We are satisfied that the IOUs are not using resource stacks.

PG&E, however, should not state a preference for particular resource types in its Plan Protocol. This may unreasonably discourage bids, or act as a hidden weighting factor. The Plan might generally assess portfolio supplies to determine the optimal mix of renewable resources with various deliverability characteristics. (§ 399.14(a)(3)(A)). Any specifics in the Plan, Plan Protocol and RFO, however, must be renewable resource neutral. Therefore, PG&E must amend its Plan, Plan Protocol and RFO as necessary to remove any specific statements of preference for renewable resource types (e.g., section titled "Ownership Alternatives, Turnkey Agreement;" elsewhere, as necessary).

F. CAISO Market Redesign

IOUs were asked to analyze and justify any proposed contract terms that would be effective upon implementation of CAISO market redesign.

1. Proposals

PG&E points out that upon implementation of CAISO market redesign, transmission under CAISO tariffs will change from a zonal to a nodal basis. This affects the definition of "delivery point." PG&E proposes language that recognizes a change in the delivery point if the CAISO market redesign occurs. PG&E states the language is the result of extensive negotiations with interested parties in a successful attempt to address the risk of potential transportation charges that might emerge during the 10-20 year term of a PPA.

SCE does not propose a contract term concerning market redesign. Rather, SCE believes it is inappropriate to adopt a standard contract term allocating risk associated with delivery in the event of market redesign. SCE contends the appropriateness of such terms depend upon unique circumstances and should be individually negotiated.

SDG&E also proposes a contract term pertaining to the definition of delivery point upon CAISO market redesign. SDG&E says it expressly reserves the right to revise the draft RFO as necessary, pending conclusion of the 2005 solicitation evaluation.

2. Adopted Term

PG&E and SDG&E each make their own proposal. Each should be permitted to employ their proposed contract term.

Aglet agrees with SCE that there may be complex issues related to risk associated with market redesign, but points out that the basic language used by PG&E and SDG&E provide protection to the utility, its ratepayers and suppliers. Aglet recommends SCE be ordered to adopt similar language. We agree.

SCE contends we should decline to allow relitigation of the issue of standard terms and conditions, and should reject Aglet's recommendation. To the contrary, the Ruling on the 2006 RPS Program specifically asked parties to address this issue. (Ruling dated November 9, 2005, page 3.) While we generally agree with SCE that IOUs should be able to use their best business judgment, we oppose individual negotiation on such a standard term. SCE shall amend its Plan and RFO to include language substantially similar to that proposed by either PG&E or SDG&E, as SCE determines best for its area (with specific references, of course, to the SCE area, as necessary).

G. Bid Selection, Evaluation, and Potential Discrimination

Each Plan describes the evaluation criteria the IOU will use to rank bids.[15] It is clear from these descriptions that the evaluation process allows room

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[15] For example:

PG&E states it will use: market valuation (either as "forwards" or "options" with consideration of debt equivalents), portfolio fit, non-price factors (credit, project status, technology viability), transmission adders, integration costs, and other non-price considerations (social, reliability, environmental, resource diversity, transmission

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for judgment. For example, PG&E specifically says one difference between its 2005 and 2006 solicitation process is that in 2006 the quantitative weightings have been eliminated, providing more flexibility and accommodation to the wide range of technologies and specific project circumstances.

Aglet is concerned with the role of judgment in the selection process, and asks: "what assurance does the Commission have that the final selection will not discriminate against a particular technology?" (Comments, page 3.) We share this concern. It is our responsibility, on behalf of the state's ratepayers and businesses, to approve a program and process that is fair and equitable. Further, it must be equitable not only between technologies but also be nondiscriminatory between bidders within a technology.

To cure this problem, Aglet recommends that each utility's contract evaluation model be determined before, not after, bids are received. At a

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network benefits, modification to solicitation requirements and agreement). (Plan Protocol, pages 25-28.)

SCE states it will take into account the criteria expressed in the Commission's LCBF decision (D.04-07-029), and will specifically employ a production simulation model to calculate total system production costs and benefits (incorporating effective load carrying capacity values, transmission costs, and integration costs and benefits), plus debt equivalence, credit and seller qualifications, and will use other attributes as tie-breakers. (RFO, pages 14-15.)

SDG&E states it will evaluate offers on the basis of an LCBF analysis with three components having primary importance (delivered energy cost, overall fit with SDG&E's resource portfolio, transmission system upgrade costs), with high emphasis on the offer prices not only as initial cost but long-term cost, and differentiation of similar cost offers using several factors (e.g., location, benefits to minority and low income areas, resource diversity, environmental stewardship, delivery reliability, ability to advance schedule, technology, operational flexibility, development risk, financing plan, corporate capabilities). (RFO, pages 21-23.)

minimum, Aglet recommends that each IOU present the Commission with a description of its contract evaluation model, inputs, and how inputs are to be weighed. DRA strongly agrees. (DRA Reply Comments, pages 1-2.) In response, IOUs argue for increased, not decreased, flexibility in the selection process. IOUs recommend against micromanagement of the procurement process. PG&E asserts that:

> "Requiring the micro justification described by Aglet would be to place a straightjacket on PG&E at a time when it is important to understand the commercial viability of a project. The utility must be able to exercise its business judgment…" (Reply Comments, page 12.)

We agree with the concerns expressed by Aglet and DRA, but conclude that the RPS project evaluation and selection process within the LCBF framework cannot ultimately be reduced to mathematical models and rules that totally eliminate the use of judgment. Rather, the process of negotiating the lowest price while shaping the best fit can involve give-and-take between bidder and IOU, and judgment by each party. We do not seek to eliminate the reasonable and proper use of judgment by any participant, including IOUs, bidders, parties and the Commission. Nonetheless, because we agree with the concerns of Aglet and DRA regarding the potential for discrimination and bias in the project evaluation and selection process, along with the need for a fair and equitable procedure, we take several steps to address these concerns now, short of adopting standard offers.[16]

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[16] A standard offer for buying electricity is similar to a standard tariff for selling electricity. It eliminates undue discrimination on the basis of project, price, bidder, technology or type.

1. IOU Report on Evaluation Criteria and Selection

First, we adopt Aglet's "minimalist" recommendation. That is, we require certain information, but decline to determine each IOU's modeling method before bids are received. We think an order now that requires IOUs to file more information on evaluation models, with comments and replies by parties followed by a subsequent Commission decision before bids are received, would unreasonably divert limited resources of parties and the Commission, and unduly delay the process.

Rather, we will require each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected. We are confident each utility can craft such report. We will hold each utility to the requirement of submitting a reasonable report consistent with our previous direction that "utilities should make their evaluation process transparent to their Procurement Review Groups and the Commission." (D.05-07-039, page 7.)

To assist each IOU complete that goal, however, we note certain elements that should be in each report. For example, it should start with an executive summary that summarizes the model, process, all bids (both winning and losing), prices, the evaluation of each bid, and any other relevant summary information. In more detail, subsequent chapters of the report should describe each IOU's evaluation criteria, selection model and the process used. It should contain a table, matrix or other device to show all evaluation factors used (both quantitative and qualitative). For the quantitative elements, it should show the bid's all-in electricity price, the most recently adopted applicable MPR, the scoring of each quantitative factor, and the final quantitative score. For the qualitative elements, it should contain a narrative description of each qualitative factor, and the evaluation of each qualitative factor for each project as it was used in the final selection process. It should conclude with the final result for each project. It must contain anything else reasonably necessary for a full and complete explanation to the Commission of the evaluation and selection process by the IOU.

Energy Division may, but is not required to, work with the IOUs on a format for this report and may, if it wishes, specify a format. That format should be designed to assist Energy Division (plus the Procurement Review Group (PRG) and others who are involved) assess the projects as they work their way through the evaluation process. It should eventually make approval of the Advice Letter (AL) for specific projects routine, since a standard format is used throughout the process, and data is updated as necessary for quick assessment.

We note that in this context the report may serve as a screening tool. We encourage IOUs and Energy Division to consider its use in that way. As such, it may potentially become more complete as the process unfolds.

For example, it may be used early in the process to initially screen projects. When more data is available (e.g., MPR), the data may be entered and the tool updated. Using the same tool with updated information, assessment, analysis and conclusions should help make the process transparent and easy to follow. It should also simplify the review of the ALs for specific projects.

Finally, if different, each IOU shall separately submit a copy of each important decision document used by the IOU's management to reach critical intermediate decisions, along with the final evaluation and selection.

2. Independent Evaluator

Because of the complexity, importance, and potential for conflicts and disputes, we also require each IOU to use an Independent Evaluator to separately evaluate and report on the IOU's entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The Independent Evaluator's preliminary report should be provided with the IOU's short list, and a final report with the AL for approval of selected bids. This requirement is independent of whether or not there are utility owned or utility affiliated projects under consideration.

The costs of the Independent Evaluator may be entered into the Long Term Procurement Memorandum Account or other appropriate account. (See D.05-07-039 and D.04-12-048). Each IOU should consult with the PRG and Energy Division Director before selecting the Independent Evaluator. To the fullest extent feasible, each IOU should seek to follow the advice of the PRG and Energy Division Director on the selection, and subsequent management, of the Independent Evaluator. In addition, as we stated in D.04-12-048, each IOU shall allow periodic oversight by the Commission's Energy Division, and shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process. The Independent Evaluator shall also make periodic presentations regarding its findings to the IOU and the IOU's PRG. (See, D.04-12-048, Findings of Fact 94-95; Ordering Paragraph 28.) Our intent is to preserve the independence of the Independent Evaluator by ensuring free and unfettered communication between the Independent Evaluator and the Commission's Energy Division, and an open, fair, and transparent process that the PRG can confirm.

3. Workshops and Use of Alternative Dispute Resolution Procedures

The November 9, 2005 Ruling directed IOUs to include a discussion of specific plans for pursuit of wind repowering. On this topic, SCE states that it sent a letter to existing wind projects soliciting interest in repowering and expansion. SCE also discussed repowering and expansion at the 2005 bidders' conference. SCE reports that it received very limited interest. According to SCE, it is unclear what has caused such a low level of response from the wind industry given their frequent public statements of interest in repowering and expansion. SCE says it is willing to sponsor a workshop specifically aimed at identifying the issues and potential solutions that would encourage a more robust response from existing projects.

We encourage SCE to do so, even though SCE does not need specific encouragement from us to conduct a workshop. Rather, IOUs are already under our direction to secure 20% renewables by 2010, and are potentially subject to penalties if they do not. That should be encouragement enough.

We re-emphasize that SCE, as all IOUs, should undertake all reasonable actions to reach the RPS goal. If that involves conducting a workshop, we are confident that SCE will do so. If SCE is later subject to penalties, but seeks reduction or waiver of those penalties, we will include in that assessment whether or not SCE took all reasonable actions, such as whether or not it conducted workshops. The burden will be on SCE to establish that it in fact took all reasonable steps, but the industry simply did not respond at the level of MPRs and SEPs.

There may or may not, however, be other tools that might be useful to advance program goals. For example, IOUs, RPS generators, and/or industry groups should consider taking advantage of resources for ADR at the Commission.

In particular, the Commission has encouraged ADR for more than two decades, and we have facilitated and approved many settlements since the 1980s. Most recently, we have adopted an expanded ADR program under the supervision of the Chief ALJ. (See Resolution ALJ-185, August 25, 2005.) We encourage parties to take advantage of our program, which includes facilitation, mediation, arbitration and early neutral evaluation.

4. Equal Treatment, Fair Dealing and Good Faith Performance

We note with approval that SCE states a seller has no liability to SCE for certain damages "provided that Seller uses commercially reasonable efforts in developing and submitting such forecast to SCE." (PPA, § 3.10(d).) SCE pledges that it "shall in good faith work with Seller" under certain conditions. (*Id.*, § 10.05.) Similarly, PG&E pledges that certain approvals will "not to be unreasonably withheld." (Solicitation Protocol, Attachment I, Master PPA for Firm Product, § 3.7(b).)

We encourage IOUs to include such language throughout their Plans, RFOs, and PPAs, as appropriate. In this way, burdens are shared and equal between parties, and obligations are neither one-sided nor unfair. The duty here is for good faith, fair dealing, and reasonable behavior by both parties.

To the extent not now clear in the Plans and proposed PPAs, each Plan and PPA should be amended to incorporate a term which requires equal treatment, fair dealing, reasonable behavior, and good faith performance from each party.[17] This should be included as a general term early in the PPA, making clear that this expectation applies to both parties throughout the entire agreement.

5. Disclaimers and IOUs Discretion

Each IOU's Plan states many disclaimers which allow it to reject offers and/or terminate the solicitation.[18] We do not limit these disclaimers per se. Nonetheless, we note that each IOU reserves for itself considerable discretion not normally available in the framework of either tariffs (when the IOU is a seller) or standard offers (when the IOU is a buyer).

We expect each IOU to achieve the 20% by 2010 requirement, absent appropriate application of flexible compliance rules. We will hold each IOU to having undertaken all reasonable action to achieve that requirement. As such, each IOU may wish to reconsider the tone and nature of its disclaimers. Each IOU may wish to present a Plan that focuses more on the many positive ways it

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[17] Such term might be modeled, in part, after an item commonly in the General Terms and Conditions section of telecommunications interconnection agreements. For example, in the recent interconnection agreement arbitration between AT&T California and Verizon Access Transmission Services, parties agreed to the following term: "Each party shall act in good faith in its performance under this agreement and, in each case in which a Party's consent or agreement is required or requested hereunder, such Party shall not unreasonably withhold or delay such consent or agreement." (Application (A.) 05-05-027.)

[18] See, for example, PG&E Solicitation Protocol, Item I.C., page 1; SCE 2005 RFP, § 1.02; and SDG&D Draft RFO, Items 1.0 (e.g., paragraph 2) and 10.0.

intends to accomplish the state policy to have 20% renewables by 2010, and how it will work with all stakeholders in reasonable ways to make that happen.

H. Evaluation Criteria, Environmental Stewardship and Water Action Plan

1. Evaluation Criteria

In adopting the RPS legislation, the Legislature specifically found and declared (§ 399.11) that increasing California's reliance on renewable energy resources to reach the target of 20% promotes the purposes of, and may do, each of the following:

- increase the diversity, reliability, public health and environmental benefits of the energy mix
- promote stable electricity prices
- protect public health
- improve environmental quality
- stimulate sustainable economic development
- create new employment opportunities
- reduce reliance on imported fuels
- ameliorate air quality problems
- improve public health by reducing the burning of fossil fuels

Further, the Legislature specifically stated that each electrical corporation, in soliciting and procuring renewable energy, "may give preference to projects that provide tangible demonstrable benefits to communities with a plurality of minority or low-income populations." (§ 399.14(a)(5).)

We have discussed these and other potential benefits from RPS generation, and bidders are encouraged to describe these benefits, if any, in their bids. We have directed IOUs to make it known in their Plans that such benefits are sought, and apply transparent criteria to evaluating such claims. (D.03-06-071, page 37.) We have further discussed this assessment by application of quantitative and qualitative factors used in bid evaluation. (D.04-07-029, page 28; also Findings of Fact 27 and 28.)

IOUs' Plans differ on their treatment of these factors. For example, some plans list several of these factors (e.g., PG&E and SDG&E). Others only say attributes identified by the Commission will be used as tie-breakers (e.g., SCE).[19]

Because we have directed IOUs to make it known in their Plans that such benefits are sought, and apply transparent criteria to evaluating such claims, we believe each IOU can and should do a better and more consistent job of actually stating the specific criteria and encouraging bidders to state such benefits, if any, in their offers. Thus, each IOU should amend its Plan to do a better job of specifically identifying and stating each factor found and declared by the Legislature, and discussed in our decisions, along with specifically encouraging bidders to address such benefits, if any.

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[19] SCE's Plan identifies these other factors under tie-breakers, and says "SCE will utilize those attributes identified in D.04-04-026 [sic] as quantitative methods for evaluating tie-breakers." (SCE 2005 RFP, Item 5.02, page 15.) It is unclear if SCE means to refer to the R.04-04-026, or to D.04-07-029 (where quantitative and qualitative factors are addressed). SCE should make this clear. More importantly, however, as we direct in this order, SCE must state each quantitative and qualitative criterion and solicit bidders to address such benefits, if any, within these criteria.

2. Environmental Stewardship and Water Action Plan

Among the criteria and benefits to consider is environmental stewardship. We include environmental stewardship as a qualitative factor for IOUs to consider when evaluating bids. (D.03-06-071, page 37; D.04-07-029, page 29.)

Our interest in the environment and environmental stewardship includes our air, land and water. IOUs must consider all aspects of the environment in their assessments. Since our last RPS decision, we have taken further action regarding environmental matters. We take this opportunity to link these actions.

In particular, on December 15, 2005, we adopted a Water Action Plan. Among our action items is:

- Educate water industry stakeholders regarding policies and practices which reduce water and energy consumption. (Water Action Plan, page 7.)

- Consider energy use as an important outcome of all water policy decisions and work toward a 10% reduction in energy consumption by the utilities over the next three years. (Water Action Plan, page 10.)

- Collaborate with the California EPA to reduce California greenhouse gas (GHG) emissions. (Water Action Plan, page 11.)

Environmental stewardship requires balancing all competing demands and supplies of precious resources to reach the best outcomes. We clarify here that environmental stewardship includes the environmental impacts of the proposed RPS generation facility on California's water quality and use. RPS projects which provide particular benefits in helping us achieve responsible and reasonable water quality, use and improved water resource management consistent with our Water Action Plan, EAP II, and environmental stewardship generally, are encouraged to identify such benefits in their proposals. IOUs are expected to include this factor in their "transparent criteria in evaluating such claims." (D.03-06-071, page 37.)

I. Multiple Bids

PG&E does not permit a bidder to simultaneously submit competing offers to other electricity corporations.[20] In contrast, SDG&E permits a bidder to submit competing offers to other electrical corporations, but the bidder must withdraw the offer from other solicitations once the bidder is selected for SDG&E's short list. (SDG&E Draft RFO, December 22, 2005, page 14 of 30.) SCE's approach is similar to that of SDG&E.[21] SDG&E's approach is superior, and PG&E is directed to amend its RFO to allow simultaneous bids in the same manner as SDG&E for the reasons stated below.

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[20] PG&E requires that the bidder state it has not provided, and will not provide, during the time the offer is deemed binding, an offer to another party. (Solicitation Protocol, Attachment A, page 1, item F.) Bidders submitting offers are bound by their offers for a period of 9 to 12 months from the date of submittal. (Solicitation Protocol, page 5, Item IV.A.) In comments on the draft decision, PG&E asserts it actually permits bidders to participate in multiple solicitations but, once the project is short-listed, the bidder must commit its project to PG&E or withdraw its bid, citing page 7 of its Solicitation Protocol in support. (PG&E Comments on Draft Decision, May 15, 2006, page 14.) Page 7 of the Solicitation Protocol, however, says if the bidder does not notify PG&E of its intent to withdraw then the bidder's offer "will remain binding." (Emphasis added.) To remain binding, it must have been previously binding.

[21] SCE requires that the seller grant SCE exclusive negotiating rights within five days of being notified the seller has been selected for SCE's final short list. (RFO, page 13, Item 4.02.) This is understood to mean that sellers may offer and negotiate simultaneous bids until selected for the final short list.

We found for the 2004 Solicitation that it is "reasonable to permit bidders to participate in more than one utility's RPS solicitation." (D.04-07-029, page 41, Finding of Fact 5.) We also found that "all bids should be treated as potentially multiple until the bids are short-listed and negotiations begin." (D.04-07-029, page 42, Finding of Fact 13.) Nothing is presented here to convince us to change that view.

Competition is diminished to the extent potential buyers and sellers face barriers to making trades, and is increased to the extent unreasonable barriers are removed. In this case, competition is reasonably increased by allowing simultaneous bids to more than one electricity corporation, at least to the point that the bidder is selected for the short list. This facilitates the fullest presentation of projects and information to the market so that buyers can make a wise selection between choices. Because of different evaluation criteria, the same project might be rejected by one IOU but selected by another. Allowing simultaneous bids is the best way to make sure the project gets full consideration.[22]

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22 For example, even if the bid price to each utility is the same, and the MPR is the same between the two utilities (so that the preliminary least cost comparison is the same), the ranking of bids by price, LCBF and other quantitative and quantitative factors might be different between the utilities. This might be because there may be a different mix of bids submitted to each IOU. It might be because the best fit assessment is different between IOUs for the same project. It might be because each IOU applies different qualitative evaluations of the same project, resulting in different raking. Also, the same bidder might have two different prices between IOUs due to different costs to serve each IOU (e.g., different interconnection or other costs). The result might be different short list selections between two utilities even with essentially the same projects for consideration.

In the interest of promoting competition, promoting full consideration of all proposals, and removing barriers to the effectiveness of the RPS program, we direct, as we did in D.04-07-029, that bidders may bid into multiple solicitations, and bids are to be treated as potentially multiple until the short lists are created. Any IOU Plan that provides otherwise must be amended.

J. Timing of Next Solicitation and Compliance for 2006

In the November 9, 2005 Ruling, IOUs were asked to address the possibility of a firm deadline for submission of contracts for Commission approval. In response, IOUs generally oppose firm deadlines, arguing that "flexibility is the key to a successfully managed power procurement solicitation." (PG&E Plan, December 22, 2005, page 10.) Both PG&E and SCE state they intend to conduct a solicitation in 2006, but SDG&E says it has not yet decided. SDG&E says it will make its final decision after conclusion of negotiations with bidders in its 2005 solicitation. (SDG&E Procurement Plan, page 4.)

In its comments, DRA recommends that IOUs follow a competitive simultaneous bid process, which DRA believes is consistent with the periodic determinations of MPRs and SEPs in the RPS statutes. Aglet recommends SDG&E conduct a solicitation in 2006. In reply comments, IOUs argue against micromanagement and "a one-size-fits-all time period for contract negotiations." (SDG&E Reply Comments, page 6.)

Annual Framework: Our approach so far has been one of giving IOUs flexibility largely within an annual framework. This is consistent with the RPS legislation which, for example, contemplates annual procurement targets. (§ 399.14(a)(3).) At the same time, however, the legislation does not specify the frequency of RPS solicitations. It also does not state the cycle for determining the

MPR, other than "after the closing date of a competitive solicitation." (§ 399.14(a)(2)(A).)

There may be a tension here between two approaches. On the one hand, the process might be very structured, with electric corporations' annual bid solicitations beginning and ending on the same dates, plus the same dates for evaluations, determinations of MPR, annual compliance reviews, and submission of contracts to Commission approval. Alternatively, the process might essentially be continuous, flexible and open to all renewable generation sellers at all times.[23] In this second approach there might be periodic determination of MPRs (e.g., so that projects may seek SEPs, as necessary), with procurements measured annually for purposes of determining APT and IPT compliance (including the application of flexible compliance rules).

We do not here make a final determination on approach. Nonetheless, we are not persuaded by IOUs' desire for broad flexibility to determine not only when, but if, they begin and end a solicitation, particularly given concerns expressed by nearly all parties regarding whether or not RPS targets may be reached by 2010. Until we are able to explore the merits, if any, of a more continuous process, the next round needs reasonable structure, similar to that which we have used to date, with a renewed focus on seeking to reach program targets.

As SCE candidly notes, there "are advantages and disadvantages to imposing a firm contracting deadline." (SCE Procurement Plan, page 16.) While parties need sufficient time to resolve and negotiate matters, we are persuaded

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23 According to SDG&E, IOUs now accomplish this via bilateral contracts, which may be signed at any time.

by SCE and UCS that one lesson learned from SCE's protracted 2003 solicitation is that "a final cutoff for submitting contracts to the Commission for approval can operate as a catalyst to resolving outstanding issues in negotiations." (*Id.*) UCS says it "agrees with SCE, as a Commission-imposed deadline on SCE's 2003 solicitation resulted in swift finality and signed contracts." (Comments, page 3.)

We accomplish this by adopting the same RPS Solicitation Timeline employed for prior solicitations, with limited additional guidance. In particular, we set dates and time intervals with the flexibility to modify those intervals if necessary. (See D.05-12-042, Appendix B; also see this order, Appendix A.)

We encourage parties to follow the schedule in Appendix A to this order. We authorize the Energy Division Director, in administration of this program, to modify the dates on Energy Division's own initiative, as necessary, in order to bring the next solicitation to conclusion by the end of 2006 or early 2007. If a party desires modification, the party may seek an extension by letter or electronic mail to the Executive Director, with copy to the Energy Division Director. (See Rule 48(b).[24])

Contracts for 2006 Targets: We previously granted IOUs, at their option, the ability to treat contracts resulting from the 2005 RPS solicitation and signed on or before June 30, 2006, as available to demonstrate compliance with their 2005 APT, for the event of deficits greater than 25%. (D.05-07-039, Ordering Paragraph 15.) Given the timing of the 2006 solicitation cycle, we again believe it

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[24] The letter or e-mail "must be received by the Executive Director at least three business days before the existing date for compliance." (Rule 48(b).) A copy must be served at the same time on all parties to this proceeding. The "existing date for compliance" is either the date in Attachment A hereto, or a modified date by notice subsequently served on all parties by the Energy Division Director.

reasonable to grant IOUs, at their option, the ability to treat contracts resulting from the 2006 RPS solicitation, but signed after December 31, 2006, as available to demonstrate compliance with their 2006 APT, for the event of deficits greater than 25%. Given the schedule adopted in Appendix A, however, the deadline for the 2006 solicitation need not be June 30, 2007. Rather, IOUs may, at their option, treat contracts resulting from the 2006 RPS solicitation and signed by the later of December 31, 2006, or within 45 days after the Commission adopts the resolution approving the PPAs from the 2006 solicitation, as available to demonstrate compliance with their 2006 APT, in the event of deficits in greater than 25%. By the schedule in Attachment A, that will most likely mean a date before June 2007.

2007 RPS Plan Cycle: In our continuing efforts to move toward a calendar year solicitation cycle, we adopt the approach used in developing and reviewing the 2006 Plans for the next solicitation cycle. (D.05-07-039, page 29.) That is, we expect the filing and service of 2007 draft RPS plans and draft RFOs later this year. The specific schedule will be set by the Assigned Commissioner or ALJ. Moreover, as we have also done before, we authorize the Assigned Commissioner to assess the adequacy of Transmission Ranking Cost Reports (TRCRs) used in the LCBF ranking of bids. (D.04-06-013, D.05-07-040.) The Assigned Commissioner or ALJ should set dates, as needed, for utilities to request information for the TRCRs, to file draft TRCRs, and for parties to file comments and replies on the draft TRCRs. The Assigned Commissioner should then assess the adequacy of the draft TRCRs, and determine whether the reports should be modified or other steps taken before the results are used in the ranking of bids. (D.05-07-040, Ordering Paragraph 7.)

Adjustments to 2006 Plan Schedule: In comments on the draft decision, several parties recommend more time in each of several parts of the timeline. We adopt some, but not all recommendations, and further adjust the schedule to focus on completion in 2006.

For example, we are persuaded by parties to grant more time for IOUs to file amended RPS Plans.[25] We also provide time (which had not been specifically identified previously) for IOUs to validate and clarify bids, as recommended by SCE. We compress time for calculation of the draft MPR (since it may be calculated simultaneously with other events, as long as it is not published before the solicitation is closed). We compress Commission time in other places where possible (e.g., timeline for preparation of draft resolution approving some or all PPAs).

We grant more time for parties to negotiate and execute PPAs after IOUs submit their short lists, but not the full 90 days recommended by some parties. Rather, RPS generators and IOUs should be fully engaged in negotiating and resolving issues as necessary through the entire process. They should not wait until the short list is developed. Each RPS generator's bid should be reasonably complete when submitted, and subsequent negotiations should be focused and limited. IOUs should develop their short lists with all, or nearly all, issues resolved, including price. Each IOU may sort its short list by price once the MPR is adopted. Although we grant some additional time, we are not

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[25] SCE asks for 30 days, citing in support that it is conducting a workshop with bidders on May 25, 2006, and may revise its RFO in response to comments made at the workshop. We encourage SCE and each IOU to make reasonable improvements to its Plan and RFOs. We point out, however, that any material change from the Plan submitted and under consideration here must be resubmitted to the Commission for the Commission to "accept, modify or reject." (§ 399.14(b).)

persuaded that parties should need a great deal of additional time to further negotiate and execute the PPA once the short list is developed.

Unless and until parties recommend—and we adopt—RPS solicitations that are essentially continuous, we want to move this process to an annual cycle that is completed at the end of each calendar year, to the fullest extent possible. As such, this solicitation cycle should be completed by the end of 2006, and we adopt a schedule with that in mind. As provided above, however, the Energy Division Director may adjust the schedule, and parties may ask for more time, to the extent necessary. Nonetheless, we expect all parties to move the 2006 solicitation process forward reasonably and without delay, unless particular facts or individual circumstances arise that necessitate and justify the granting of more time.

K. Other items

1. SCE's 2006 Procurement Target

SCE states it will seek to "procure the difference between its high procurement needs obligation…and the amount of contracted-for output available in 2010 from its 2005 solicitation." (Plan, page 10.) Aglet suggests that SCE spread its procurement over four years (2006-2009) instead of attempting to procure all its remaining needs in 2006. As such, Aglet recommends that SCE set a minimum procurement goal in 2006 of 25% of the difference between its high needs obligation and the amount of contracted for output. (Aglet Comments, page 7.) We disagree, and reject Aglet's recommendation.

The state's RPS goal is not 20% **in** 2010, but 20% **by** 2010.[26] There is nothing that reasonably prohibits reaching this goal before 2010. While parties talk generally about incurring too much cost by agreeing to contracts now versus later, they provide no specific or compelling evidence. For example, we have no good estimate at this time of whether the MPR will be more or less next year than this year. Moreover, the program itself is designed to control costs. That is, no bids above the MPR need to be accepted by IOUs, nor approved by the Commission. Thus, ratepayers are never burdened with costs above the reasonable long-term cost of the alternative. Whether or not the state incurs costs above the "market" cost via SEPs is a decision for the CEC, taking into account all the factors that will properly be before them. We reject Aglet's suggestion, and strongly encourage each IOU to aggressively pursue RPS generation now.

2. Other Items

Parties comment on several other items, such as confidential treatment of elements of each Plan and use of Renewable Energy Credits (RECs). Confidentiality has been, or will be, addressed soon by ALJ Ruling. Other important matters will be decided soon by subsequent Commission decision.

V. Issues Specific to an IOU Plan

We comment further below on issues specific to each Plan. We agree with UCS's recommendation, however, that conditional approval of these Plans does not constitute endorsement or adoption of proposed policy measures that have not yet been fully vetted or decided. (UCS Comments, page 4.) Rather, we

[26] The accelerated RPS goal is "20 percent renewables by 2010." (EAP II, October 2005, page 8.) An entity may seek to reach this goal before 2010.

conditionally approve each Plan subject to the amendments required and suggested herein. Each utility, however, remains ultimately responsible for proposing and executing reasonable Plans that achieve the requirement of 20% renewables by 2010, subject to our flexible compliance rules.

A. PG&E

PG&E's Plan states that transmission-related costs will be part of the evaluation, and "projects must bid to one of the selected [transmission] clusters." (Solicitation Protocol, page 18.) At the same time, PG&E states it intends to accept bids from any eligible renewable resource anywhere in California. If the bid must be to one of the clusters, it appears that PG&E intends for the project to incur the transmission cost to get the electricity to that cluster. This may or may not be consistent with PG&E agreeing to take electricity from anywhere in California. PG&E should amend its Plan to make PG&E's expectations clear regarding who pays the transmission cost, or whether that is negotiable, and make clear how out-of-service territory bids will be evaluated.

PG&E's Plan refers to a participant forfeiting its bid deposit if the participant withdraws other than pursuant to a "permitted withdrawal." (Solicitation Protocol, page 7.) It is unclear if "permitted withdrawal" is solely at PG&E's discretion, or if there are conditions which define permitted withdrawal. PG&E should make this term clear.

PG&E's Master PPA for a firm product requires sellers to abide by a certain standard of care. (Solicitation Protocol, Attachment I, Item 3.5, page 17.) If not required elsewhere in the PPA, PG&E should state in Item 3.5 that generating asset owners (GAOs) are subject to the Commissions' GO 167 (unless the GAO is exempted by the terms of GO 167). PG&E's other PPA (e.g., for intermittent sources) should contain this or a similar statement.

PG&E's Master PPA for a firm product requires that sellers perform maintenance only during the three months of March to May of each year. (Solicitation Protocol, Attachment I, Item 3.7(b), page 18.) Sellers are also obligated to a performance requirement of 80% (super-peak), 75% (shoulder) and 55% (night) during March to May, or are subject to performance adjustments (reduced payments). (*Id.*, Item 4.5, page 25.) It does not appear that an allowance is made for scheduled maintenance. PG&E should modify this and its other PPAs to make reasonable accommodation for planned maintenance without performance adjustments, if not now allowed.

B. SCE

SCE was directed (as were PG&E and SDG&E) to "allow bids that have curtailability as an attribute." (D.05-07-039, Ordering Paragraph 9(b).) SCE's 2006 RPS Plan states that its 2005 RFO allowed for curtailability. (Procurement Plan, December 22, 2005, page 14.) SCE clarifies, however, that this means bidders can submit dispatchable bids. (*Id.*) SCE "defines dispatchable products as those generating facilities that are able to be turned on or off at any time by SCE, at its sole discretion…" (*Id.*, page 14, footnote 7.) Dispatchable by SCE at its sole discretion, however, is not what we meant by accepting bids that have curtailability as an attribute. Rather, dispatchable by SCE may be one form of curtailability. SCE must also entertain bids in which the bidder agrees to curtail itself under certain conditions, not necessarily at SCE's sole discretion. That is, where the bidder "may also propose less-than-full deliverability of product output." (D.05-07-039, page 11.) We made this order to cast a wider net for projects. (*Id.*, page 10.) SCE should amend its Plan to permit this wider net.

SCE's RFP states several references that guide a renewable generator's interconnection and operation. (SCE 2005 RFP, Item 6.10, pages 20-21.) With limited exceptions, all generating asset owners are subject to the Commission's GO 167. Unless otherwise exempt, an RPS generator is subject to GO 167.[27] SCE should amend its plan to include reference to GO 167.

SCE's 2005 Pro Forma PPA states the terms under which a Development Fee shall be returned to a seller (e.g., successful initial operation). (PPA, § 304(c), page 19.) SCE states that it will be returned "without interest." In other cases, deposits are returned (or credited toward other fees, deposits or collateral) with interest. For example, SCE returns both the proposal deposit and short list deposit with interest. (SCE 2005 RFP, Item 3.05(c)(ii).) There is no known reason for this inconsistent treatment. SCE should amend its PPA to provide for the return of this and other similar fees, deposits or collateral with interest.

C. SDG&E

SDG&E's Plan does not state its 2006 IPT. Its Plan should be amended to do so.

SDG&E states that it "reserves the right to revise both its RFO and EEI Agreement prior to issuance." (Procurement Plan, page 6.) To the extent such revision is contrary to this or any Commission order, including the Commission's overall direction for the program, that reservation of rights is denied. (§§ 399.14(b) and (d).) The need or usefulness of SDG&E making this statement in its Procurement Plan is unclear. We suggest SDG&E delete this statement when its Plan is amended pursuant to this order.

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[27] Qualifying Facilities (QFs) are generally exempt. (See GO 167, § 2.8.2.) If an RPS generator is a QF, it may be exempt. RPS generators are not otherwise categorically exempt from GO 167.

SDG&E requires RFO Responses to provide "pricing for energy to the point of interconnection with the CAISO grid and to the point of delivery into SDG&E's service area." (Draft RFO, Item 4.13, page 11.) Just as discussed above for PG&E, SDG&E should amend its Plan to make SDG&E's expectations clear regarding who pays the transmission cost, or if that is negotiable, and how out-of-service territory bids will be evaluated.

SDG&E's draft RFO refers to a "Scope of Work" that appears not to be defined. SDG&E should do so, or change the term to "scope of request" consistent with the reference to Section 1.0. (Draft RFO, Item 7, page 18.)

SDG&E's Plan refers to a credit application. (Draft RFO, Item 12, page 27.) It also refers to an Offer Response Form, Additional Narrative Information Sheet, and Consent Form. (Draft RFO, Item 14.0, page 29.) These documents are neither included with SDG&E's document, nor is the website to which parties are referred available. SDG&E should provide copies with its amended Plan.

SDG&E's Plan states that it has not decided whether or not to have a solicitation in 2006, and will make that decision when the 2005 solicitation is complete. We think that is poor judgment. There is clearly a band of uncertainty with regard to demand, supply and transmission issues, making it unclear whether the 20% by 2010 goal can be achieved without constant effort and repeated, vigorous solicitations. This is not the time for any IOU to err on the side of inaction.

For example, a solicitation now might reveal more projects within SDG&E's service area, and without the need for expensive new transmission, than SDG&E currently foresees. The best way to tell this is not with surveys and studies, but an actual test of the market. We understand that a solicitation is not without cost. The cost to SDG&E of such solicitation, however, can be properly managed and controlled by SDG&E. As such, it should not be large. Further, if SDG&E has requested funding from ratepayers, the reasonable costs of the solicitation are already included in SDG&E's rates recoverable from ratepayers (or reasonable amounts will be included in future rates if requested by SDG&E). There is no cost to bidders if no bidder responds. If they do, however, it provides all stakeholders the opportunity to determine whether or not these bids are good for California. On balance, the cost of a solicitation by SDG&E is minor compared to the larger interest of the state reaching its RPS goal of 20% by 2010.

Moreover, there is nothing that prohibits SDG&E from achieving 20% before 2010. We think SDG&E should aggressively pursue this possibility. Further, we think SDG&E's Plan and PPAs should be improved as discussed herein, and this is an opportunity for SDG&E to do so.

We will not order SDG&E to conduct a solicitation, but we will evaluate SDG&E's decision should SDG&E later (beyond the flexible compliance rules) fail to achieve a 1% IPT, or 20% by 2010, and seek a reduction or waiver of a penalty. Absent very good reason to the contrary, we expect to see each IOU conduct a solicitation at least once each year, and—if IOUs assist us craft it—on a continuous basis.[28]

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[28] In comments filed May 15, 2006, SDG&E explains that at the time it filed its 2006 Plan it had not decided whether or not to conduct a solicitation in 2006 because, at that time, it was "unable to predict with any reasonable degree of certainty what the outcome of its 2005 solicitation would be, or what impact the results of the 2005 solicitation would have on the need for a 2006 solicitation." (May 15, 2006 Comments, page 13.) Given the lead time to develop projects, transmission issues and other concerns and constraints, we continue to view SDG&E's early lack of commitment to a 2006 solicitation with concern. Nonetheless, SDG&E now reports "SDG&E has since decided that it will in fact conduct another renewables solicitation in 2006." (*Id.*, page 13.)

VI. TOD Benchmarking Methodology

In December 2005, we adopted a recommendation to approve utilities' TOD factors during the review of utilities' RPS procurement Plans and proposed RFOs. (D.05-12-042, pages 21-22.) We said, however, that in order to do this a methodology for evaluating reasonableness of utilities' TOD profiles is required, on a schedule to be determined by the Assigned Commissioner and assigned ALJ. A schedule was set by ruling dated December 27, 2005. IOUs provided proposed methods on which parties commented. We now address the proposals and comments.

A. IOU Proposals and Comments

The IOUs propose TOD benchmarking methodologies with some similarities and many differences. Each proposal includes use of forward prices. The proposals vary, however, by the degree of quantitative evaluation or qualitative assessment used in the benchmarking exercise. They also differ in their treatment of energy costs (e.g., whether the energy assessment uses on-peak hours only, or averages of 8,760 hours broken into other subsets), and the treatment of capacity costs in the assessment of capacity.

Comments also span a range. Some parties recommend that the Commission adopt one benchmarking methodology that is to be used by all three IOUs. Others recommend use of public (not fee-based) data. Comments also differ on the recommended use of capacity values. A summary of each IOU proposal and the comments is contained in Appendix B.

B. Discussion

No comments lead us to reject any specific TOD factors, and we adopt them as proposed by IOUs, including the update provided by PG&E in its supplemental filing on February 8, 2006. We are not convinced, however, that any benchmarking proposal is sufficiently developed, documented, or explained to be explicitly endorsed or adopted by us at this time. We address the most important specific items and comments below.

1. Uniform Benchmarking Method

We decline to adopt the recommendation that any one benchmarking method be adopted and used by all three IOUs. PG&E correctly notes that we have already decided that each utility may develop its own TOD factors, such that they best reflect each utility's market-based valuation of electricity in different time periods. (D.05-12-042, page 53, Finding of Fact 7.) Utility specific TOD factors are developed using different methods by the IOUs, and the benchmarking methodologies may reasonably also reflect such differences. Moreover, none of the methodologies is sufficiently explained or developed here to merit universal adoption. We do not permanently foreclose the option of adopting one benchmarking method in the future, if one is proposed and shown to reasonably apply to all three IOUs, but we do not do so here.

2. Forward Prices Based On NYMEX And One Day

We decline to adopt Aglet's proposal to require the use of forward prices posted on the New York Mercantile Exchange (NYMEX) website. An IOU or party may use prices posted on the NYMEX website for the purpose of a benchmarking exercise if it wishes, but we will not require NYMEX as the only source. If non-public information is used by an IOU, parties may obtain access to such data after executing an appropriate confidentiality agreement. Moreover, as SDG&E correctly points out, we use fee-based sources for data where necessary (e.g., gas price indices used to calculate monthly commodity gas prices, short-run avoided costs for QFs, calculation of the MPR).

We also decline to adopt Aglet's proposal that the benchmarking be done based on price data from the last day of the calendar year. Trade volumes are typically lower during the last week of the year than during other times of the year, and may not be sufficiently representative of market prices. Further, near-term forward prices for NP-15, such as available from NYMEX, are closely linked to forecast hydro conditions. Using forward prices from only one day (or one week) is unlikely to provide reasonable long-term prices if the hydro situation at that time differs from average hydro conditions. While we do not foreclose a party from using end of year data for a benchmarking exercise, we neither limit the use of data to the last day of the year, nor to a limited number of days at year-end.

3. Capacity Values in Benchmarking Exercise

Aglet recommends that IOUs not use capacity benchmarks or combustion turbine proxies in their benchmarking analyses. We decline to adopt this recommendation.

TOD factors should recognize the extent of the need for additional capacity. TOD benchmarking methodologies should similarly reflect the extent of that need. That is, RPS contracts may run 10 or 20 years. To the extent capacity is needed over 10 to 20 years, TOD factors and TOD benchmarks should reasonably reflect that need.

4. TOD Factors for SCE

Solel recommends that 2006 TOD factors for SCE and PG&E be applied to the 2005 solicitations, evaluations and signed contracts. Otherwise, Solel claims the contracting process could be delayed by at least a year (as projects withdraw from the 2005 solicitation and bid in the 2006 solicitation), important renewable peaking resource development might be delayed (for the same reason), and unwarranted reliance on SEPs might occur (since 2005 factors relative to 2006 factors undervalue peak periods and may require more SEPs in 2005). We first address the recommendation with regard to SCE, and reject it for the following reasons.[29]

We ordered the update to SCE's TOD factors because we determined that SCE's TOD factors were developed in the mid-1990s for purposes unrelated to the RPS program, were not appropriate for the MPR, and should be updated to rely on current market information. (D.05-12-042, page 20.) We directed SCE to recalculate its TOD profiles using market forward energy price information in a fashion similar to that of PG&E and SDG&E. We also ordered that SCE make this change for its 2006 solicitation, but decided not to require the change for SCE's 2005 solicitation, recognizing there would be an inconsistency.

Solel's proposal effectively appeals, and seeks reversal of, our December decision. Solel's arguments are unpersuasive. We already considered and rejected the same or similar arguments. We understood there would be an

[29] We note that SCE filed updated TOD factors for use in its 2006 solicitation on January 10, 2006, as ordered in D.05-12-042. On January 17, 2006, SCE proposed its TOD benchmarking methodology. On February 8, 2006, SCE supplemented its benchmarking methodology to propose a validation methodology. Solel now proposes that SCE's February 8, 2006 pleading be used for the 2005 solicitation. SCE's February 8, 2006 supplement, however, provides a validation methodology based on publicly available data, but does not update SCE's TOD factors. Therefore, we understand Solel's recommendation to be with respect to SCE's January 10, 2006 updated TOD factors.

inconsistency between SCE's 2005 and 2006 TOD factors, but reasoned that this difference would be less problematic than the potential for delay and confusion. (D.05-12-042, page 20.) We specifically adopted SCE's proposal that TOD factors for a particular solicitation cycle be "hardwired" into any and all contracts signed during that cycle. (*Id.*, page 22.)

SCE opposes Solel's proposal, contending that it has formulated its short list from the 2005 solicitation. Ordering SCE to re-evaluate its 2005 bids will introduce confusion and delay (which we considered and addressed just a few months ago in deciding not to order SCE to change its TOD factors for its 2005 solicitation). It is important to bring the 2005 solicitation to completion. We now can move forward quickly with the 2006 solicitation. We also have no data on the amount of SEP funds at issue here, if any, and whether that amount is, or should be, a material consideration in this decision. Thus, we decline to reverse our December 2005 decision now, but will proceed forward as expeditiously and efficiently as possible.

5. TOD Factors for PG&E

Solel also recommends that we order updated TOD factors for PG&E's 2005 solicitation, based on the 2006 TOD factors developed in PG&E's February 8, 2006 supplement. PG&E does not oppose using its 2006 TOD factors for its 2005 solicitation. PG&E says it has analyzed this change on its 2005 short list, and the parties on the short list do not change. PG&E further recommends, however, that the 2005 bidders be given the choice to adopt either the 2005 or 2006 TOD factors, and, if they adopt the 2006 factors, they should be required to re-calibrate their offer prices to ensure no change to the revenue requirement implicit in their bids. We decline to adopt either a mandatory or optional update for all the same reasons we rejected this for SCE, and those stated below.

Bidders relied on the factors published in the 2005 bid to make their offers. Those bids and TOD factors should be permitted to go forward, so that we may bring the 2005 solicitation to a close reasonably soon. An inconsistency, if any, between PG&E's 2005 and 2006 TOD factors is less problematic than delay and confusion introduced by requiring updates for all bidders, or permitting updates for individual projects. The potential for delay and confusion is further increased if we require re-calibration of price offers to ensure revenue requirement neutrality for some or all projects. We seek to bring the 2005 solicitation to a close by June 30, 2006. There is little time left from the filing of this order to the completion of the 2005 solicitation. On balance, it is best to complete the 2005 cycle, and move forward without delay on the 2006 cycle.

6. Adjust TOD Periods

GPI suggests that SCE and SDG&E adjust their TOD periods. For example, SCE might, according to GPI, move (a) the month of June from summer to winter season, and (b) some afternoon weekend and holiday hours in July through September from off-peak to partial peak. Similarly, according to GPI, SDG&E might (a) consider three rather than two seasons, and (b) reassign some weekend and holiday days during summer and the November-December periods. GPI also believes hourly profiles are superior to the use of six or nine TOD periods.

We decline to adopt GPI's recommendation. The benchmarking methodology exercise here is not for the purpose of adjusting TOD periods. The TOD periods used here are generally consistent with General Rate Case (GRC) results, TOD periods in tariffs, and other uses of TOD periods. SCE points out its current 2006 GRC includes a showing on TOD periods that it believes validates the TOD periods in use here. Parties may litigate such changes in future GRCs or other proceedings, as appropriate. GPI's showing, however, is insufficient to justify any changes here.

Moreover, we have already considered and rejected GPI's proposal to time-differentiate the MPR using more than six to nine TOD periods. (D.05-12-042, pages 20-21.) We determined that GPI had not documented quantitative benefits of its method that are commensurate with the radically greater granularity of its proposal. GPI similarly fails to do so here. GPI's showing neither convinces us to reconsider our prior decision, nor that any changes in TOD periods are needed now.

SDG&E supports prospective modification of its TOD profile. SDG&E says: "in the spirit of promoting renewable resources, SDG&E supports the idea of including Saturdays in its on-peak and mid-peak periods as part of its TOD factor for its next RPS solicitation." (Reply Comments, page 6.) SDG&E does not believe it is necessary to split its TOD factors into three seasons, however. We encourage SDG&E and parties to consider prospective modification to TOD periods where reasonable.

VII. Close Proceeding and Move Record to New OIR

We began our work implementing the RPS program in R.01-10-024. We opened this proceeding, R.04-04-026, in April 2004 to continue implementation of the RPS program. On December 16, 2004, the Assigned Commissioner issued the Scoping Memo in R.04-04-026, identifying the next steps to be taken in RPS program development.

Through March 2006, we have issued 13 decisions in R.04-04-026. We have addressed many issues including adoption of an MPR methodology; adoption of standard terms and conditions; adoption of criteria for selection of LCBF renewable resources; conditional approval of Plans and RFOs for the 2005 solicitations; conditional approval of the long-term Plans; establishing the basic parameters for participation of energy service providers, community choice aggregators, and small and multi-jurisdictional utilities; and adoption of the 2005 MPR methodology. We have now accomplished most, if not all, of the goals stated in the Scoping Memo.

In February 2006, we opened R.06-02-012 to continue our work on RECs, as well as the RPS program for other electric corporations (e.g., energy service providers). We simultaneously, or will soon, open another new proceeding to continue implementation of the RPS program for limited, specific other issues. For example, we will address possible improvements to the reporting methodology based on a staff White Paper, plus comments and reply comments filed in March 2006, in this proceeding. Also, the assigned ALJ will rule on pending motions for confidentiality (most likely after release of our upcoming order in R.05-06-040). To facilitate that effort, and take full advantage of the work already done by parties here without requiring that work to be redone, we incorporate the entire record from R.04-04-026 into the new OIR.

As a result, all issues which need to be addressed in R.04-04-026 are resolved. R.04-04-026 is closed.

VIII. Comments on Draft Decision

The draft decision of ALJ Burton W. Mattson in this matter was mailed to the parties in accordance with § 311(g)(1) of the Pub. Util. Code and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on May 15, 2006, by PG&E, SCE, SDG&E, DRA, Aglet, GPI, UCS, CalWEA, Coalition of California Utility Employees, and Independent Energy Producers (IEP). Letters in support of IEP comments were also served on each Commissioner and the service list by

Caithness Energy and Ormat Nevada, Inc. PG&E also filed Supplemental Comments on Reporting and Compliance, a Confidential Appendix to Supplemental Comments on Reporting and Compliance, motion for leave to supplement its comments on reporting and compliance, motion for leave to file confidential appendix under seal, and motion for order to shorten response to seven days. Reply comments were filed on May 22, 2006, by PG&E, SCE, SDG&E, Aglet, GPI, CalWEA, IEP, and Center for Energy Efficiency and Renewable Technologies.

IX. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Anne E. Simon and Burton W. Mattson are the assigned ALJs for this proceeding.

Findings of Fact

1. PG&E proposes accepting bids from eligible renewable resources with delivery points anywhere in California.
2. To the extent reporting problems are now resolved, accepting bids from eligible resources with delivery points anywhere in California casts a wider net for projects and helps IOUs meet program goals.
3. Future transmission needs may be somewhat different for RPS versus non-RPS scenarios, but the essential choice is between RPS with related transmission and other resources with related transmission.
4. IOUs are already engaged in contingency planning, with a margin of safety included in their procurement plans.
5. IOUs must meet APT and IPT requirements (with adjustments for flexible compliance) or face penalties.

6. IOUs' statements demonstrate that they understand that they are ultimately responsible for program success each year and by 2010, subject to flexible compliance rules.

7. The RPS Procurement Plans adopted by the Commission before, and adopted here, provide sufficient opportunity for each IOU to succeed, and larger IPTs or other margins of safety need not be adopted to stimulate IOUs to reach program goals.

8. The year 2010 is the year by which the Commission expects 20% of energy sold to retail end-users to be delivered from eligible renewable resources.

9. GPI and DRA are correct that the full earmarking proposal is an effort to roll back the 2010 RPS date, if not all the way back to 2017, then back to somewhere between 2010 and 2017, and, in combination with flexible compliance for 2010, it pushes the compliance date back to at least 2013.

10. We rejected full earmarking and flexible compliance proposals in 2003, and again in 2005, because we wanted to prevent continuous roll-over of the 25% shortfall, with a utility falling so far behind in its RPS procurement that it jeopardizes attainment of program goals.

11. No evidence supports the assertion that denial of full earmarking and flexible compliance in 2010 will increase the cost of the program; nor that an increase in cost, if any, is material; nor that the increase, if any, is greater than the benefits of the program; nor that the increase, if any, is greater than the incremental benefits of obtaining program goals sooner; while the use of funds above MPR is a matter that should be decided by public officials with that duty after they weigh all competing interests, goals and arguments.

12. PG&E identifies issues that make problematic the signing of contracts by June 30, 2006 for the 2005 solicitation results.

13. Neither PG&E, SCE nor SDG&E, in their role as a utility company, includes any discussion in their RPS Procurement Plans of the utility building renewable generation resource itself.

14. PG&E does not require a bid deposit until a bidder is selected for the short list, while SCE requires a bidder to deposit $25,000 simply to submit a bid.

15. The RPS developers' views of what RPS-eligible renewable resources are likely to be available is at least as important, if not more important, than the utilities' views, because developers are uniquely situated to know whether or not particular resources are worth developing and bidding into a utility solicitation.

16. We have previously noted the dangers of using resource stacks to pre-screen or discourage bids, and stated that we do not want resource stacks to act as hidden weighting factors in bid evaluations.

17. PG&E states a preference for particular resource types in its Plan Protocol, and this may unreasonably discourage bids, or act as a hidden weighting factor.

18. The language proposed by PG&E and SDG&E regarding a change in delivery point upon CAISO market redesign provides protection to the utility, its ratepayers and suppliers.

19. The RPS project evaluation and selection process within the LCBF framework cannot ultimately be reduced to mathematical models and rules that totally eliminate the use of judgment.

20. Several measures can increase the fairness and equity in the bid and selection process, provide the Commission the opportunity to review the use of judgment by the IOUs in the process, increase the transparency of the process, and allow the Commission to take corrective action if necessary including:

a. an IOU report (which can be used as a screening tool) presented to the PRG and the Commission (and available to the service list and the public, with confidential treatment of protected information) that explains each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected;

b. a preliminary and final report from an Independent Evaluator (separate and in addition to the IOU report) on the entire bid, solicitation, evaluation and selection process (available to the utility, PRG, Commission, service list and public, with confidential treatment of protected information);

c. inform all stakeholders about the ADR resources available at the Commission;

d. include an equal treatment, fair dealing and good faith performance clause in each RFO; and

e. inform IOUs the Commission will later assess the extent to which each IOU retains extremely broad disclaimer and discretion language in its RFO in a non-compliance enforcement action.

21. IOUs' Plans differ on the thoroughness with which they identify many of the benefits found by the Legislature and this Commission despite our direction that IOU Plans (a) make it clear that these benefits are sought, (b) encourage bidders to state such benefits, if any, in their bids, (c) apply transparent criteria in evaluating such claims.

22. IOU Plans can do a better and more uniform job of specifically stating benefits identified by the Legislature and Commission, and encouraging bidders to address such benefits, if any.

23. Environmental stewardship, as a qualitative factor to consider in assessing RPS bids, includes the environmental impacts of the proposed RPS generation facility on California's water quality, use and water resource management consistent with the Commission's December 15, 2005 Water Action Plan.

24. PG&E's proposal does not permit a bidder to simultaneously submit competing offers to other electricity corporations.

25. A final cutoff for submitting contracts to the Commission for approval can operate as a catalyst to resolving outstanding issues in negotiations, bring swift finality, and result in signed contracts.

26. It is reasonable to grant IOUs, at their option, the ability to treat contracts resulting from the 2006 RPS solicitation as available to demonstrate compliance with their 2006 APT, in the event of deficits greater than 25%, even if the contract is signed after December 31, 2006, as long as the contract is signed within 45 days of Commission adoption of the resolution approving PPAs from the 2006 resolution.

27. The state's RPS goal is not 20% **in** 2010, but 20% **by** 2010, and there is nothing that reasonably prohibits the state or electric corporations from seeking to reach this goal before 2010.

28. Individual elements of each IOU's Plan are—or appear to be—unclear, inadequately defined, referenced but not included, inconsistent with other elements, or inconsistent with prior Commission orders.

29. No comments recommend rejecting any specific TOD factors.

30. No TOD benchmarking methodology proposal is sufficiently developed, documented, or explained to be explicitly endorsed or adopted at this time.

31. In December 2005, we considered and rejected Solel's recommendation that SCE's 2006 TOD factors be applied to SCE's 2005 solicitations, and nothing presented here merits reversal of that order.

32. Using PG&E's 2006 TOD factors for its 2005 solicitation, and potentially also requiring bidders to re-calibrate their offer prices to ensure no change to the

revenue requirement implicit in their bids, unreasonably introduces the potential for delay and confusion.

33. The TOD benchmarking methodology exercise here is not for the purpose of adjusting TOD periods; the TOD periods used here are generally consistent with GRC results, TOD periods in tariffs, and other uses of TOD periods; we have already considered and rejected GPI's proposal to time-differentiate the MPR using more than six to nine TOD periods; and GPI did not previously document quantitative benefits of its proposed method that are commensurate with the radically greater granularity of its proposal, and fails to do here.

34. Most, if not all, issues which need to be addressed in R.04-04-026 are resolved and remaining issues, if any, can be efficiently handled, without requiring parties to redo work, by incorporating the record here into a new proceeding.

35. No party requested evidentiary hearing.

Conclusions of Law

1. Electrical corporations should be given flexibility in the way they satisfy RPS program requirements, subject to Commission guidance, limited specific program requirements, and a specific timeframe for the next solicitation cycle.

2. Conditional approval of each Plan and RFO does not constitute endorsement or adoption of each element of each Plan and RFO; rather, IOUs remain responsible for overall program success, subject to flexible compliance and tests of reasonableness.

3. Each proposed RPS procurement Plan and draft RFO filed by PG&E, SCE, and SDG&E should be conditionally approved, subject to the guidance, changes and clarifications stated in this order, including each of the following:

   a. allow deliveries anywhere in California

b. decline to adopt an IPT of 1.2%, but, in exchange

   1) each IOU must continue to include its own procurement margin of safety

   2) each IOU must provide limited additional reporting on the progress of each project meeting its development and initial operation milestones (semi-annual compliance reports; notice to Energy Division when a major project milestone is missed)

c. retain existing flexible compliance rules and seek achieving all reasonable program goals without adoption of full earmarking or flexible compliance for 2010

d. encourage, and in some cases direct, each IOU to:

   1) consider whether or not to build their own renewable generation

   2) consider reducing bid and other deposits

   3) not employ resource stacks in resource selections

   4) amend Plans to reflect renewable resource neutrality

   5) amend Plans to address CAISO market redesign as ordered herein

   6) reconsider disclaimers and elements of IOU discretion

e. remove barriers to program success by adopting the following measures:

   1) require each IOU to report (with its short list of bids and also on submission of advice letters for contract approval) on evaluation criteria and solicitation results, with the report submitted to the PRG and Commission, served on the service list, and available to the public (subject to confidential treatment of protected information)

2) require each IOU to employ an Independent Evaluator to separately report (a preliminary report with the short list, final report with IOU advice letter to approve contracts) on its entire bid, solicitation, evaluation and selection process, with the report submitted to the utility, PRG and Commission; served on the service list; and available to the public (subject to confidential treatment of protected information)

3) encourage each IOU to hold any workshop it believes will advance the program

4) advice parties they may consider using the many ADR tools available at the Commission

5) require each IOU to include an equal treatment, fair dealing and good faith requirement in their RFOs

6) require each IOU to include a clear and consistent statement of evaluation criteria in its Plan, including the benefits of the RPS program identified by the Legislature and in Commission orders

7) provide clarity on environmental stewardship and the relationship to the Commission's Water Action Plan

8) permit multiple simultaneous bids

f. Each individual IOU should amend its plan as explained in this order in areas such as, but not limited to:

1) clarify treatment of transmission (PG&E and SDG&E)

2) include references, where appropriate, to Commission GO 167 (PG&E and SCE)

3) include payment of interest on deposits (SCE)

4) include IPT (SDG&E)

5) strongly encourage a 2006 solicitation (SDG&E)

g. Each Plan is subject to being executed pursuant to the schedule for the next solicitation cycle (see Appendix A)

4. PG&E, SCE and SDG&E should each submit amended Plans and amended RFOs to the Director of the Energy Division within 15 days of the date of this order and, unless suspended by the Energy Division Director within 20 days of the date of this order, each utility shall proceed to use its amended Plan and RFO for its 2006 RPS program and solicitation.

5. The Energy Division Director should modify the adopted schedule and timeframes on the Division's own initiative, as necessary, to bring the next solicitation to reasonable conclusion by the end of 2006 or early 2007, while IOUs and parties should propose schedule modification, if any, by letter to the Executive Director pursuant to Rule 48.

6. Previous orders should be restated so that it is clear to each IOU that it ultimately remains responsible for program success, within application of flexible compliance criteria, and the Commission will later evaluate the extent of that success, including the degree to which each IOU elects to take the guidance provided herein; reasonably demonstrates creativity, innovation and vigor in program execution; and reaches program targets and requirements.

7. In a future defense of a non-compliance penalty, if any, the IOU should be required to show it took all reasonable actions to achieve compliance, and the burden to show why compliance was not met should rest with the utility, including, but not limited to showing that:

a. The IOU brought problems with achieving program goals to our attention without unreasonable delay; proposed reasonable solutions; filed applications for necessary projects (e.g., transmission lines, utility owned generation projects) and other program elements, as necessary, without unreasonable delay; and took all other actions reasonably necessary to address potential problems in reaching RPS program targets.

b. The margin of safety adopted by the IOU was reasonable, a higher margin could not have been reasonably foreseen at reasonable cost to have achieved RPS program goals and requirements, and the IOU reasonably managed its adopted margin of safety.

c. The IOU undertook reasonable consideration of building its own renewable generation facilities, including a consideration of an increased rate of return authorized for eligible utility renewable generation facilities.

d. Bid deposits before creation of the shortlist were required; bid deposits greater than those of PG&E are based on good cause; and in all other respects all bids, deposits and collateral requirements were not unreasonable and did not unreasonably prevent RPS projects from being proposed and developed.

e. Disclaimers and IOU discretion that an IOU retains in each Plan were not unreasonable and did not unreasonably prevent RPS projects from coming forward to be proposed and developed.

f. All workshops an IOU could reasonably foresee as helpful to renewable generator development were conducted by the IOU.

8. IOUs should, at their option, have the ability to treat contracts resulting from the 2006 RPS solicitation, but signed after December 31, 2006, as available to demonstrate compliance with their 2006 APT, in the event of deficits greater than

25%, as long as those contracts are signed on or before 45 days after the Commission adopts the resolution approving PPAs from the 2006 solicitation.

9. PG&E's request to defer the earmarking deadline for the 2005 solicitation from June 30, 2006 to September 30, 2006 should be granted.

10. The Assigned Commissioner or ALJ should set a schedule for the filing and service later this year of 2007 draft RPS plans and draft RFOs; should set a schedule related to TRCRs; and the Assigned Commissioner should determine whether draft TRCRs should be modified, or other steps taken, before the TRCRs are used in the LCBF ranking of bids.

11. The law permits an IOU to procure renewable generation from itself and states it is not to be understood to imply that the purchase of electricity from third parties in a wholesale transaction is the preferred method of fulfilling a retail seller's RPS obligations.

12. The 2006 TOD factors developed by SCE and PG&E should not be used for either utility's 2005 RPS solicitation.

13. This record should be incorporated into a new OIR.

14. Evidentiary hearing is not necessary.

15. This proceeding should be closed.

16. This order should be effective today so that the 2006 RPS solicitation may proceed without delay, the record may be incorporated in the new OIR without delay, and pending matters may be addressed in the new proceeding without delay.

O R D E R

IT IS ORDERED that:

1. The following documents, which are the utility proposed renewables portfolio standards (RPS) procurement plans (Plans) and Power Purchase Agreements (PPAs) or Requests for Offers (RFOs), are conditionally approved for the next RPS solicitation cycle:

   a. The Pacific Gas and Electric Company (PG&E) "2006 Renewable Energy Procurement Plan" and "Renewables Portfolio Standard Solicitation Protocol" filed December 22, 2005, and the "Supplement to the Draft 2006 Renewables Portfolio Standards Solicitation Protocol of Pacific Gas and Electric Company Filed December 22, 2005 and TOD Factors Benchmarking Study" filed February 8, 2006.

   b. The Southern California Edison Company (SCE) "2006 Renewables Portfolio Standard Procurement Plan" filed December 22, 2005 (including the 2006 Request for Offers (RFOs) represented by SCE to be substantially identical to SCE's 2005 RFO), and the SCE "2006 Time-of-Delivery Factors" filed January 10, 2006.

   c. The San Diego Gas & Electric Company (SDG&E) "2006 Short-Term Renewable Procurement Plan" filed December 22, 2005.

2. Each document referenced above is adopted on the condition that:

   a. Within 15 days of the date of this order, PG&E, SCE and SDG&E shall each file with the Director of the Energy Division, and serve on the service list, an amended Plan and PPA or RFO consistent with all the orders in this decision, plus all guidance in this decision with which the utility agrees, in particular as identified in Conclusion of Law 3.

b. Unless suspended by the Energy Division Director within 20 days of the date of this order, each utility shall use each amended Plan and PPA or RFO for its next solicitation.

3. The 2006 RPS procurement cycle shall be as stated in Appendix A. The schedule may be modified by the Energy Division Director as reasonable and necessary for efficient administration of this solicitation, with the goal of bringing this solicitation to reasonable conclusion no later than early 2007, and parties shall comply with any such modified schedule. Parties may seek schedule modification by letter to the Executive Director (pursuant to Commission Rules of Practice and Procedure), and, if granted, shall be subject to any such modifications.

4. Each utility ultimately remains responsible for reasonable RPS program outcomes, within application of flexible compliance criteria. The Commission shall later review the results of renewable resource solicitations submitted for Commission approval, and accept or reject proposed contracts based on consistency with each approved Plan. The Commission shall also judge the contract results, program results, and non-compliance pleadings by, but is not limited to, considering the degree to which each utility reasonably elects to take or reject the guidance provided herein; reasonably demonstrates creativity, innovation and vigor in program execution; reaches program targets and requirements; shows it took all reasonable actions to achieve compliance, including but not limited to the factors identified in Conclusion of Law 7.

5. PG&E's request to defer the earmarking deadline for the 2005 solicitation from June 30, 2006 to September 30, 2006 is granted for PG&E.

6. Each utility shall, at its option, have the ability to treat contracts resulting from the 2006 RPS solicitation, but signed after December 31, 2006, as available to demonstrate compliance with its 2006 Annul Procurement Target, in the event of

deficits greater than 25%, as long as those contracts are signed on or before 45 days after the Commission adopts the resolution approving the PPAs resulting from the 2006 solicitation.

7. The Assigned Commissioner or ALJ in Rulemaking (R.) 04-04-026 (or its successor proceeding with regard to ongoing implementation and administration) shall set a schedule for the filing and service later this year of draft RPS plans and draft RFOs for the 2007 solicitation, and subsequent draft RPS plans and draft RFOs, as necessary. The Assigned Commissioner or ALJ shall set a schedule for matters related to Transmission Ranking Cost Reports (TRCRs) to be used in the ranking of bids in an RPS solicitation. The Assigned Commissioner shall assess the adequacy of each TRCR based on filed comments and reply comments, and shall determine whether each TRCR shall be approved, modified, or other steps taken before a TRCR is used in ranking bids in an RPS solicitation.

8. Each utility shall allow periodic oversight of the work of the Independent Evaluator by the Commission's Energy Division, and shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process. The Independent Evaluator shall also make periodic presentations regarding its findings to the utility and the utility's Procurement Review Group (PRG). This process shall preserve the independence of the Independent Evaluator by ensuring free and unfettered communication between the Independent Evaluator and the Commission's Energy Division, and an open, fair, and transparent process that the PRG can confirm.

9. The record in R.04-04-026 is incorporated into the record in a new Order Instituting Rulemaking (OIR) on the RPS program. The motions for confidential treatment of certain portions of some pleadings in R.04-04-026 shall be part of the record incorporated into the new OIR, and the motions shall be ruled upon there.

10. No hearing is necessary.

11. R.04-04-026 is closed.

This order is effective today.

Dated May 25, 2006, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

Commissioner Dian M. Grueneich recused herself from this agenda item and was not part of the quorum in its consideration.

APPENDIX A

RPS SOLICITATION TIMELINE

(Updated from D.04-07-029 and D.05-12-042)

- Utilities file annual RPS procurement plans and RFOs.

- CPUC approves procurement plans and RFOs.

- Utilities issue RFOs.

- Respondents file notice of intent to bid.

- Deadline for respondents to submit bids.

- Utilities notify CPUC when bidding has closed.[1]
  Notification by letter to Executive Director.

- MPR is calculated by Commission when last solicitation is complete.
  CPUC staff calculates and discloses draft MPR in a draft resolution. After party comments, MPR is finalized when Commission adopts MPR resolution.

- Utilities evaluate the bids to develop short lists.[2]
  PRG meetings are held to review bid results.

- Utilities issue short-listed bids to CPUC and PRGs.
  Bidders have five days to withdraw all conflicting bids. Otherwise bid is binding.

- PRGs and CPUC review utilities' short lists.

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1 CPUC staff are not allowed to see the results of the RPS solicitations until the Commission adopts the MPR resolution.

2 Utility evaluation process may begin prior to MPR release and adoption.

- Utilities and bidders negotiate and execute contracts.

- Utilities submit contract advice letters for CPUC approval.

    It may be appropriate for utilities to file contracts in groups as final agreements are reached. Contracts that do not require SEP funds could be submitted separately.

- CPUC reviews advice letters submitting contracts.

- Contracts are approved by adoption of Commission resolution.

- Sellers confirm PGC funding with utilities within 10 days after receiving notice of SEP determination from Energy Commission.

    After SEP determination is made, generators and utilities may re-structure payment streams in their contract or take other actions in accordance with Standard Terms and Conditions, "SEP Awards, Contingencies," based on SEP determination.

    If SEP award is not made within 120 days of submission of the contract for CPUC approval, generators may exercise termination rights under the provisions of Standard Terms and Conditions, "SEP Awards, Contingencies."

- If necessary, utilities submit amended advice letters with revised proposed contracts, reflecting results of SEP determinations, to CPUC for review and approval by resolution.

<u>NOTE ON SEPs</u>

Contracts approved by CPUC and having a contract price greater than the MPR may be eligible for SEPs. The Energy Commission's instructions for submitting applications and supporting materials are set forth in the current *New Renewable Facilities Program Guidebook*, available at http://www.energy.ca.gov/renewables/documents/index.html. Thirty days after receiving a contract and all relevant data required to conduct the SEP evaluation, the Energy Commission releases PGC Funding Confirmations to CPUC, utility, and individual bidder, and will identify any caps imposed. Final SEP awards are subject to conditions identified in the current *New Renewable Facilities Program Guidebook*.

ADOPTED SCHEDULE
FOR 2006 SOLICITATION

ITEM	NO. OF DAYS	APPROXIMATE DATES
CPUC's Conditional Approval of RPS Plans	0	5/25/06
IOUs file amended RPS Plans	15	6/9
IOUs issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 20)	22	6/16
Respondents file Notice of Intent to Bid	29	6/23
Bidders Conferences	36	6/30
Deadline for Bids	92	8/25
IOUs validate and clarify bids	99	9/1
IOUs notify CPUC Executive Director when Bidding Closed	103	9/5
MPR calculated and Draft Resolution filed	103	9/5
IOUs develop Short Lists		
CPUC Adopts MPR Resolution	133	10/5
IOUs submit short lists to PRGs and CPUC (with report on evaluation criteria and selections; also Independent Evaluator Preliminary Report)	134	10/6
PRGs review IOU Short Lists		
IOUs and bidders negotiate and execute PPAs	158	10/30
IOUs submit ALs with PPAs for CPUC Approval (with updated IOU report on evaluations and selections, and Independent Evaluator's Final Report)	166	11/6
Draft Resolution Approving some or all PPAs in ALs	174	11/14
CPUC adopts Resolution on PPAs (last meeting in 2006)	204	12/14
Sellers confirm PCG funding with IOUs within 10 days of receiving SEP notice from CEC	234	1/13/07
IOUs submit amended AL, as necessary, with revised proposed contracts reflecting SEPs	244	1/23
Draft Resolution Approving some or all amended PPAs	251	1/30
Commission adoption of Resolution on Amended PPAs	281	3/1

(END OF APPENDIX A)

APPENDIX B

SUMMARY OF TOD BENCHMARKING METHODOLOGY PROPOSALS AND COMMENTS

A summary of the TOD benchmarking methodology proposals and comments follows.

1. PG&E Proposal

PG&E proposes comparing on-peak TOD factors developed from published on-peak forward power prices to a set of modified IOU-specific RPS TOD factors that have been modified to reflect a comparable on-peak time period. PG&E initially proposed this based on the relative value of forward energy prices. PG&E modified this via a later supplement to incorporate in both its TOD factors and methodology the residual fixed costs of new peaking resources. PG&E says, given PG&E's need to meet Commission-adopted resource adequacy requirements, it is appropriate to account for the additional cost of new peaking capacity, which will be needed as early as 2008. The original and revised TOD factors are as follows:

Monthly Period	Super Peak		Shoulder		Night	
	Orig	Rev	Orig	Rev	Orig	Rev
June-Sept	1.502	1.959	0.992	0.903	0.716	0.626
Oct-Dec; Jan-Feb	1.343	1.471	1.090	1.030	0.810	0.731
March-May	1.114	1.319	0.928	0.843	0.676	0.584

Source: February 8, 2006 Supplement, page 5
Original: December 22, 2005 Solicitation Plan based on energy only
Revised: February 8, 2006 Supplement to Draft 2006 RPS Solicitation Protocol based on energy and new peaking capacity

PG&E says deviations between TOD factors and benchmarks should be expected and should not serve as an indicator of error or unreasonableness. Rather, according to PG&E, deviations might indicate the need for further investigation. PG&E illustrates its energy benchmarking methodology and reports:

Period	Modified On Peak RPS TOD Factor	On Peak TOD Ratios based on Market Forward Information
June-Sept	1.20	1.20
Oct-Dec; Jan-Feb	1.20	1.18
Mar-May	1.00	1.09

PG&E proposes as its capacity benchmarking methodology the calculation of net capacity cost in three steps. First, the annual real economic carrying charge fixed cost of a new combustion turbine can be benchmarked using publicly available sources when actual market bids are not available. Second, expected net energy benefits are calculated using the Black option model as a function of several variables (e.g., NP 15 peak energy forward price; citygate natural gas prices; variable operation and maintenance costs; volatility of NP 15 peak energy forward prices; volatility of citygate gas forward prices; correlation between peak energy forward prices and gas forward prices). PG&E recommends using current market information rather than historic information. Third, the net capacity cost is calculated. PG&E says the allocation of the resulting net capacity cost does not involve proprietary information, and is allocated using the allocation factor formula PG&E currently uses to allocate capacity payments to qualifying facilities.

2. SCE Proposal

SCE's 2006 TOD factors are as follows:

Season	TOD		
	On	Mid	Off
Summer	3.28	1.28	0.67
Winter	1.02	0.82	0.65

Source: SCE's January 10, 2006 compliance filing pursuant to D.05-12-042, page 2.

SCE proposes close inspection of SCE input data and methodology in lieu of a separate benchmarking process. SCE says it believes a detailed review of the inputs and methodology utilities use to calculate TOD profiles is the appropriate way to evaluate those profiles. According to SCE, this is because TOD factors are forward looking for 10 to 20 years using prospective data, and the benchmarking process must also use prospective data. SCE asserts that, in the near-term, there will never be any proof that the factors selected are correct. To the extent the benchmarking process relies on publicly available historic data, there is a significant probability of a disconnect, according to SCE. Thus, SCE asserts that the process of exercising quality control on the data and methods used to calculate the TOD factors is itself the benchmarking effort.

In its supplement, SCE restates that instead of benchmarking, SCE recommends the Commission exercise quality control over SCE's data and methodology. SCE says the Commission can exercise this quality control by using a validation methodology that reasonably recreates SCE's data and methodology while replacing SCE's proprietary data with publicly-available data. SCE's validation methodology uses four pieces of data: annual SP 15 forward 7x24 electricity prices; SCE's incremental cost of firm capacity, as defined by a combustion turbine proxy; SCE's relative loss of load probability factors by TOD period; and historical hourly SP 15 Power Exchange data. SCE proposes forward electricity price data that can be purchased by the public from brokers. Other data comes from SCE's 2006 General Rate Case or historical data. SCE performs an illustrative calculation, which shows SCE TOD factors differ from validation factors by between zero and 14%. Relying entirely on publicly-available data will not allow precise replication of SCE's filed TOD factors, according to SCE. Nonetheless, SCE says the two sets of factors are reasonably consistent and illustrate that SCE's TOD factors are fair and reasonable.

3. SDG&E Proposal

SDG&E's TOD factors are as follows:

Season	TOD		
	On	Semi	Off
Summer	1.6293	1.0400	0.8833
Winter	1.1916	1.0790	0.7928

Source: Procurement Plan, December 22, 2005, Appendix A, page 12

SDG&E recommends TOD profiles be benchmarked for reasonableness based on the logic of the calculation, and the reasonableness of the underlying assumptions, using a qualitative evaluation, not a quantitative assessment. SDG&E says its TOD factors are based on the following factors, almost all publicly-available: historical California Power Exchange hourly price data adjusted so the on-peak to off-peak ratios equal those from the 2006 SP-15 forward electric market. The forward prices are available to the public through a fee-based subscription, according to SDG&E.

SDG&E says the logic of its TOD profile is that the hourly PX profile is an adequate hourly profile, but is based on hydro and weather conditions in 1999-2000, which should be updated based on current forward prices. SDG&E adjusts all hourly prices proportionately, but says other methods are available and the Commission must assess whether proportional adjustment is reasonable. Adjustments should also be judged for reasonableness based on external implications, according to SDG&E. For example, SDG&E asserts an adjustment that makes the TOD profile more "peaky" should be consistent with a utility resource plan showing the need for peaking resources.

SDG&E says it will work with its PRG and Energy Division to provide adequate information to ensure success of the benchmarking process, and success will occur if the process does not require extensive utility or Commission resources while satisfying the Commission that the TOD profiles are reasonable. SDG&E says confidential data will be redacted in public versions of the data.

4. DRA Comments

DRA recommends that all utilities use an approach similar to SCE's for benchmarking TOD proposals (largely because DRA finds SCE's TOD proposal best reflects the correlation between TOD and capacity values). DRA also proposes the application of a hypothetical solar plant to benchmark the utility TOD factors.

5. Aglet Comments

Aglet recommends that the Commission adopt the energy benchmarking proposal of PG&E for all IOUs (with some modification), but that IOUs not use capacity benchmarks or combustion turbine proxies in their benchmarking analyses. Further, Aglet recommends use of forward prices from the New York Mercantile Exchange website from the last trading day of the year, not from sources which require paying a fee. Aglet believes that non-market participants should be allowed to participate in investigations of divergent TOD/benchmarking results.

6. GPI Comments

GPI finds that IOUs have produced TOD factors for their 2006 solicitations that are reasonably representative of expected future values profiles, although they could be made better. GPI recommends benchmarking against historic market information, and utility demand curves, as well as quality control measures. GPI believes hourly profiles are superior to a more limited number of TOD periods, and that more periods should be considered, at least in some cases.

7. Solel Comments

Solel believes the PG&E and SCE Supplements represent better approaches to evaluating and calculating TOD profiles, they should accepted, and they should be applied to the 2005 as well as 2006 and future RPS solicitations.

(END OF APPENDIX B)