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Decision 09-06-018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 08-08-009 (Filed August 21, 2008)

DECISION CONDITIONALLY ACCEPTING 2009 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN SUPPLEMENTS

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DECISION CONDITIONALLY ACCEPTING PROCUREMENT PLANS FOR 2009 RENEWABLES PORTFOLIO STANDARD SOLICITATIONS AND INTEGRATED RESOURCE PLAN SUPPLEMENTS

1. Summary

The California Renewables Portfolio Standard (RPS) Program requires that each California electric utility procure, with limited exceptions, an annual minimum quantity of electricity generated from eligible facilities powered by renewable energy resources. The amount, subject to flexible compliance provisions, must increase by at least 1% each year, and must reach 20% of total retail sales by no later than 2010.

As part of fulfilling this requirement, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) must each prepare an RPS procurement plan (Plan). The Commission is required to review and accept, modify or reject each Plan before commencement of renewables procurement. Sierra Pacific Power Company (Sierra) and PacifiCorp (collectively multi-jurisdictional utilities, or MJUs), must file a biennial Integrated Resource Plan (IRP), along with limited supplemental information. Sierra and PacifiCorp must file more comprehensive Supplements in years in which an IRP is not filed. The Commission reviews each IRP and Supplement.

In this decision, we conditionally accept the Plans filed by SCE, PG&E, and SDG&E. We also review the Supplements to IRPs filed by Sierra and PacifiCorp. Important steps we take include:

1. Require an Imperial Valley special bidders conference.
2. Require specific monitoring of Imperial Valley proposals and projects.

3. Adopt a requirement for a more standardized project viability methodology and calculator, and increased transparency of the bid evaluation process.
4. Adopt a uniform date before which an investor-owned utility (IOU) may not require that a bidder execute an agreement requiring exclusive negotiations with the IOU.
5. Require IOUs to exclude language that would discourage or prohibit bids longer than 20 years, and require IOUs to consider and evaluate all bids.
6. Accept IOU proposals for modifications to least-cost, best-fit protocols and descriptions.
7. Direct SDG&E to provide both energy-only and all-in time of use (TOU) factors with its next TOU showing.
8. Commend utilities for innovative work (e.g., PG&E proposal to include joint development and ownership; SCE RPS Standard Contract Program) and continue to encourage utility-owned RPS generation as necessary to meet RPS goals, when consistent with Commission procurement protocols and where appropriate and reasonable.
9. Accept SDG&E's proposal to include an Imperial Valley sub-solicitation as part of its general solicitation in 2009, consistent with allowing SDG&E to fulfill its Sunrise Powerlink Transmission Line commitments.
10. Adopt a schedule for completing the 2009 solicitation cycle and process for initiating the 2010 solicitation cycle.

SCE, PG&E and SDG&E shall each, within 14 days of the date this order is mailed, file and serve an amended Plan, with a copy also filed on the Director of the Commission's Energy Division. Each utility shall proceed to use its amended Plan for its 2009 RPS program and solicitation, unless the amended Plan is suspended by the Executive Director or Energy Division Director within 21 days of the date this order is mailed. Sierra and PacifiCorp may each use its IRP and Supplement without delay. A more comprehensive summary of requirements for the amended Plans and future Supplements is in Appendix A. The 2009 solicitation schedule is in Appendix B.

We continue to employ the presumption that each utility may apply its own reasonable business judgment in running its solicitation, within the parameters we establish and the guidance we provide. Utilities ultimately remain responsible for program implementation, administration and success, within application of flexible compliance criteria. We will later judge the extent of that success, including the degree to which each utility implements the orders adopted herein, elects to take the guidance provided herein, demonstrates creativity and vigor in program administration and execution, and reaches program targets and requirements. This proceeding remains open.

2. Background

Senate Bill (SB) 1078 established the California RPS Program effective January 1, 2003.[1] Several Plans have been implemented, and solicitations held, by SCE, PG&E and SDG&E under the RPS Program.

On May 29, 2008, we completed the specification of MJU obligations under the RPS Program. This includes the filing of an MJU's biennial IRP in some years (along with limited supplemental information), and the filing of a more comprehensive Supplement to its IRP in other years. (Decision (D.) 08-05-029.) The timing of MJU IRPs results in the consideration of a more comprehensive Supplement to each IRP for 2009.

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[1] Stats. 2002, Ch. 516, Sec. 3, codified as Pub. Util. Code §§ 399.11, et seq., as amended by SB 107 (Stats. 2006, Ch. 464, Sec. 13, effective January 1, 2007). All subsequent code section references are to the Public Utilities Code unless noted otherwise.

2.1. Rulemaking 06-02-012

On April 3, 2009, three issues pending in Rulemaking (R.) 06-02-012 were transferred to this proceeding for consideration and disposition. (*See* Assigned Commissioner's Ruling (ACR) Transferring Consideration of Issues.) To the extent they relate to the 2009 RPS Procurement Plans and Supplements, we address these issues in a companion order.

2.2. Rulemaking 08-08-009

On June 20, 2008, an Amended Scoping Memo identified certain elements with respect to 2009 Plans for SCE, PG&E and SDG&E, and Supplements to IRPs for Sierra and PacifiCorp, and set the schedule. On June 26, 2008, a motion for extension of the schedule was granted.[2]

On September 15, 2008, the three largest Investor-Owned Utilities (IOUs) filed and served their 2009 RPS Plans, and the two MJUs filed and served Supplements. On October 1, 2008, the three IOUs filed draft Transmission Ranking Cost Reports (TRCRs). On October 15, 2008, comments on the 2009 Plans and Supplements were filed by nine parties.[3] Comments on the draft TRCRs were also due on October 15, 2008, but no comments were filed. On

[2] *See* Ruling dated August 12, 2008.

[3] Comments were filed by the Commission's Division of Ratepayer Advocates (DRA), jointly by the Center for Biological Diversity (the Center) and the Sierra Club, jointly by the California Cogeneration Council (CCC) and the Solar Alliance, jointly by the Large-Scale Solar Association (LSA) and the California Wind Energy Association (CalWEA), L. Jan Reid (Reid), and SDG&E.

October 22, 2008, reply comments were filed on the Plans and Supplements by four parties.[4]

Motions for evidentiary hearing were due by October 29, 2008. No motions were filed, and no hearing was held.

On December 18, 2009, we granted a Certificate of Public Convenience and Necessity (CPCN) for the construction of the Sunrise Powerlink Transmission Project (Sunrise). (D.08-12-058.) We noted the relationship of certain Sunrise issues to the 2009 RPS Procurement Plans, and directed the assigned Commissioner to put forth specific proposals for comment. On February 3, 2009, an ACR identified the proposals and, to address certain issues, also included, a Staff Proposal to refine the methodology used to assess project viability. On or about February 27, 2009, comments were filed by 13 parties.[5] On March 6, 2009, reply comments were filed by eight parties.[6]

On February 27, 2009, SCE moved to bifurcate certain Sunrise issues for treatment in the 2009 Procurement Plan decision, with others to be treated later. On March 6, 2009, PG&E responded in support. On March 16, 2009, DRA responded in opposition. By ruling dated April 29, 2009, the motion was denied. By ACR dated April 29, 2009, the draft TRCRs were accepted for use with the

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[4] Reply comments were filed by The Utility Reform Network (TURN), SDG&E, PG&E and SCE.

[5] Comments were filed by PG&E, SCE, SDG&E, DRA, Center for Energy Efficiency and Renewable Technologies (CEERT), Green Power Institute (GPI), LSA, Sempra Generation (Sempra), Independent Energy Producers Association (IEP), Reid, Union of Concerned Scientists (UCS), CalWEA, and Stirling Energy Systems, Inc (SES). These comments are noted later herein as Sunrise Comments.

[6] Reply comments were filed by PG&E, SCE, DRA, CEERT, GPI, Reid, UCS, and CalWEA. These comments are noted later herein as Sunrise Reply Comments.

2009 Plans. At the request of the Administrative Law Judge (ALJ), on May 8, 2009, SCE filed standard contracts and other materials related to SCE's RPS Standard Contract Program.

3. Overview of 2009 Plans, 2009 Supplements and Commission Approach

3.1. Overview of 2009 Plans and Supplements

Each utility covered by the RPS Program is required each calendar year to procure, with some exceptions, a minimum quantity of electricity generated from eligible facilities powered by renewable energy resources.[7] This minimum is measured as a percentage of total retail sales and is generally known as the annual procurement target, or APT. Each utility 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%. This is generally known as the incremental procurement target, or IPT, and results in annual incremental growth in the APT. (§ 399.15.) Each utility must, subject to certain flexible compliance provisions, reach 20% by 2010.[8]

[7] Exceptions include, for example, the use of provisions which allow flexible compliance.

[8] While statutes provide for 20% by 2010, the goal of 33% by 2020 has been established in other ways. For example, as early as October 2005, the California Energy Commission (CEC) and this Commission jointly adopted Energy Action Plan II (EAP II) identifying as a key action item the implementation of 33% by 2020 (subject to cost-benefit and risk analysis). (EAP II, at 8.) In February 2008, we concluded that retail sellers should be expected to increase RPS procurement each year toward a goal of 33% by 2020 but should not be subject to penalties for failure to procure more than 20% by 2010. (D.08-02-008, Conclusion of Law 13.) On November 17, 2008, the Governor established an RPS target by which all retail sellers shall serve 33% by 2020. (Executive Order S-14-08.) On December 11, 2008, the California Air Resources Board (CARB)

Footnote continued on next page

Each utility, as part of fulfilling these requirements, must prepare a Plan for the procurement of RPS-eligible energy. 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 flexible compliance mechanisms established by the Commission, and (c) a bid solicitation.

The Plans of SCE, PG&E, and SDG&E (the three largest utilities) are subject to Commission review and acceptance, modification or rejection prior to the commencement of renewable resource procurement. (§ 399.14; D.03-06-071.[9]) For the MJUs (Sierra and PacifiCorp), we review the biennial IRP (with limited supplemental information) and, in years without an IRP, an expanded Supplement to the IRP.[10] (D.08-05-029.) The Commission does not require the MJUs to engage in the same solicitation cycle required of the three largest utilities. Therefore, the MJUs need not await Commission action before their commencement of renewable resource procurement.

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adopted a Scoping Plan for implementation of California's greenhouse gas statute (Assembly Bill 32; Stats. 2006, Ch. 598, codified at Health & Safety Code § 38500 et seq.). CARB's Plan includes implementing 33% renewable resources in the electricity sector by 2020. (D.08-12-058, at 6.) Finally, SDG&E offered to commit, upon the approval of Sunrise, to achieve 33% by 2020. On December 18, 2008, we accepted SDG&E's commitment to reach 33% by 2020, and approved the project. (D.08-12-058, at 260.)

[9] Also *see* D.05-07-039, D.06-05-039, D.07-02-011, D.08-02-008.

[10] All RPS-obligated load serving entities (LSEs) must meet five basic elements of the RPS Program. These are: (1) 20% by 2010; (2) increase annual procurement by 1%; (3) report on progress; (4) use of flexible compliance; and (5) uniform penalty provisions. The LSEs include not only large utilities but also MJUs, small utilities, electric service providers (ESPs) and community choice aggregators (CCAs). The MJUs (Sierra and PacifiCorp) must file IRPs and certain Supplements to IRPs. The small utilities (i.e., Bear Valley, Mountain Utilities), ESPs and CCAs are not required by the Commission to file annual procurement plans. (*See* D.06-10-019 and D.08-05-029.)

The Plans are summarized in Appendix C. The Supplements are summarized in Appendix D.

3.2. Overview of Commission Approach

We have followed an approach of "flexibility with accountability" as we allow utilities to fulfill their duties under the Program. That is, we have granted RPS-obligated utilities considerable flexibility in the way they satisfy RPS Program goals. In exchange, each utility must meet its RPS Program targets, within application of flexible compliance criteria. The Program includes penalties for unexcused failures to meet targets.

Our responsibility includes accepting, rejecting or modifying the procurement Plans of SCE, PG&E and SDG&E before a particular solicitation. We also review the IRPs and Supplements to IRPs of the MJUs. We do not, however, write any Plan, IRP or Supplement; dictate with precise detail the specific language of any Plan, IRP or Supplement; nor do we micro-manage what is in the Plan, IRP or Supplement. Rather, each utility has considerable flexibility to develop and propose its own Plan, IRP and Supplement. Our review is at a reasonably high level. Neither do we take over the procurement process. Each entity is ultimately responsible for achieving successful procurement using its Plan, IRP or Supplement pursuant to, and consistent with, the RPS Program.

Our responsibility also includes reviewing the results of solicitations. It includes accepting or rejecting proposed contracts, based on consistency with approved Plans, when the contracts are submitted for approval. (§ 399.14(d).) The Plans accepted herein are a fundamental, but not necessarily the only, part of that review (as described in prior decisions, including D.06-05-039, D.07-02-011 and also below). Similarly, the Supplements will be a fundamental, but not necessarily the only, consideration when reviewing an MJU's compliance with RPS Program obligations.

We have conditionally accepted prior Plans, provided guidance, taken steps to broaden and enhance the quantity and quality of RPS bids, and improved the contracting process.[11] We continue to do so here. We do not repeat existing Commission directions, requirements and guidance. Rather, all existing directions and guidance remain unchanged unless specifically addressed otherwise herein.

We first address several issues that arose during our consideration of Sunrise. Next, we address several issues common to all Plans. We then address limited issues specific to a particular Plan or Supplement. We conclude by adopting the schedule for 2009 RPS solicitations and the process for considering 2010 Plans.

4. Sunrise Issues

In the decision authorizing a CPCN for Sunrise, we identified four proposals for possible consideration in our review of the 2009 RPS Procurement

[11] For example, we require IOU Plans to: (a) include consideration of proposals with delivery points anywhere in California; (b) incorporate reasonable margins of safety (e.g., allowing for some possible project delays or failures while still meeting Program targets); (c) include interest on deposits; and (d) clearly state the evaluation criteria used in the LCBF selection process. We have also (a) adopted revised standard terms and conditions (STCs) for model contracts to increase contracting flexibility; (b) included solicitation of short-term contracts within approved Plans to promote flexibility; (c) recognized individual utility initiative as part of the utility's Plan in order to facilitate creativity, while accepting the utility's proposal to defer certain decisions (e.g., SCE Biomass Program); and (d) permitted eligible contracts to be treated as a pool rather than require earmarking to identify a specific contract for future satisfaction of a deficit. (*See*, for example, D.06-05-039, D.07-02-011, D.07-11-025, and D.08-02-008.)

Plans. (D.08-12-058, at 263-268.) We directed that the assigned Commissioner issue a ruling with these proposals and seek comment. (*Id.*, Ordering Paragraph 14.) The last proposal involved four issues. To facilitate consideration of these four issues, Energy Division developed a project viability evaluation methodology. The Energy Division proposed methodology was attached to the ruling for parties' consideration and comment.

Respondents and parties provided many useful comments. We first discuss the initial three proposals. We then address the last proposal and four issues in our discussion of the staff proposal.

4.1. Special Imperial County Bidders Conference

We said in the Sunrise decision that we expected approval of Sunrise to prompt proposals from RPS-eligible renewable developers for viable, competitively priced projects in the Imperial Valley. We also said we expected these proposals as early as in response to the 2009 RPS solicitation. To increase the likelihood of this outcome and to highlight the opportunities enabled by Sunrise, we proposed that each respondent utility hold a special bidders conference in Imperial County. (*Id.*, at 266-267.)

Several parties support, or do not oppose, a special Imperial Valley bidders conference. Other parties contend it would be redundant and unnecessary. For example, IEP asserts that sophisticated bidders are well aware of the RPS process, and a special conference makes sense only if an IOU has already planned the 2009 solicitation without consideration of Imperial Valley resources. CalWEA says a bidder with any wherewithal will be able to travel to a utility's regular bidding conference. Reid is concerned that a special conference might give the impression that a preference will be given to Imperial Valley developers, and that projects in other areas need not apply. This is counterproductive to overall RPS development, according to Reid. SCE says that most developers who might build in Imperial Valley do not have their business development staff in that area. SCE points out that it did not find it necessary to have a special Tehachapi bidders conference, but has received significant bids from that area.[12] SCE does not object to holding a special conference in Imperial Valley, but is uncertain that it is necessary.

Despite these concerns, we are convinced that a special Imperial Valley bidders conference has merit. A special bidders conference will highlight the unique opportunities created by Sunrise. We expect it to increase both the number and viability of proposed projects. The conference itself should not be unduly expensive, but it should help facilitate economically efficient and optimal use of the nearly $2 billion Sunrise investment. We also endorse SDG&E's proposal that the Commission encourage (but not mandate) utilities developing their own set of affirmative actions to increase awareness among Imperial Valley renewable developers.

We recognize the concerns of IEP and others, however, and permit the three IOUs to each schedule their special conference at a time and place that it believes is most efficient for the IOU and stakeholders. This may be on the same day and at the same place as the regular bidders conference, but held as a special part of that conference, in order to separately and uniquely highlight and discuss the new opportunities in the Imperial Valley. Alternatively, it may be held

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[12] SCE notes that it achieved significant bids by stating within its RPS solicitation a preference for projects within the Tehachapi area, and properly valuing the benefits of projects sited near approved transmission infrastructure, without giving unfair preference to non-viable or uncompetitive Tehachapi projects.

separately from the regular bidders conference at a time and place the IOU determines to be reasonable.

We also agree with CEERT regarding inclusion of certain subjects that highlight the special importance and unique expectations relative to Imperial Valley renewable resources and Sunrise. In particular, we expect each conference host to explain:

1. The key elements of the Commission's decision approving Sunrise, including our express intention to use all regulatory tools at our disposal so that the renewable resources enabled by Sunrise are developed;
2. The size, route, status and construction schedule of Sunrise;
3. The estimate of 1,900 megawatts (MW) of Imperial Valley renewables expected to be delivered over Sunrise by 2015, with more than half of that development from high capacity geothermal resources, and
4. SDG&E's commitments to:
    a. Not contract for any length of term with conventional coal generators that deliver power via Sunrise,
    b. Replace any approved renewable energy contract deliverable via Sunrise that fails with a viable contract with a renewable generator located in Imperial Valley (e.g., a minimum of 2,253 gigawatt-hours (GWh) per year),[13] and
    c. Voluntarily raise its RPS goal to 33% by 2020.

[13] D.08-12-058, at 265, footnote 680. We note that 2,253 GWh per year is about 500 MW at 50% capacity factor (CF).

We also acknowledge the view of CalWEA that projects outside Imperial Valley may create significant flows on Sunrise.[14] The special bidders conference should accept those possible effects and, as such, should be open to, and welcome, any bidder within the region of the Western Electricity Coordinating Council (WECC) whose project might create this type of important flow on Sunrise.

Finally, as part of their 2010 RPS Procurement Plans, IOUs should report on their experience with the special Imperial Valley bidders conference in 2009, and the reasonableness of a special Imperial Valley bidders conference in 2010. We will use this information in deciding how to proceed with future special bidders conferences, if any.

4.2. Specific Monitoring of Imperial Valley Proposals

In the Sunrise decision, we also discussed a role for Energy Division in determining whether attractive Imperial Valley projects make it through the 2009 solicitation. We suggested that Energy Division specifically monitor Imperial Valley proposals submitted in response to each IOU's 2009 solicitation. The ACR stated that utilities, and other entities as appropriate, should be required to provide certain information and updates, so that Energy Division might reasonably fulfill this role.

Several parties endorse this proposal. Other parties express concerns. The IOUs state that creation of reports for Energy Division would be reasonably easy.

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[14] CalWEA points to "2,600 MW of proposed wind projects in Baja California … [which] are very likely to produce power flows on Sunrise that are essentially equal to those created by Imperial Valley resources." (Sunrise Comments, at 6.)

Sunrise is an important project in California. It deserves reasonable attention to ensure that it is used efficiently, equitably and wisely. We conclude that specific monitoring of proposals and projects for transmission over Sunrise has merit.

Utilities and other entities should, therefore, work with Energy Division to identify the necessary data and manner of reporting that is most efficient and effective. We also expect this information to be updated, particularly with bids in 2010 and thereafter. To ease the burden on reporting entities, Energy Division should seek to include this Imperial Valley information, to the extent feasible, as part of routine compliance or other reports. As discussed more below, this may also include information on why certain projects are not selected.

We consider the concerns of, but are not persuaded by, those who oppose this special monitoring. For example, Reid is concerned that special reporting may be counterproductive because it will discourage other bidders, and create the impression that a preference is being given to Imperial Valley developers. We disagree. Bidders will participate in RPS solicitations from all locations within the California and the WECC based on their abilities and interests. There is no credible evidence that monitoring will discourage bidders. Monitoring does not mean that preference is given to Imperial Valley developers.

CalWEA believes specific monitoring of Imperial Valley bids will create pressure on utilities to select these bids even when contrary to LCBF evaluation. We are not persuaded. The nearly $2 billion investment in Sunrise warrants special monitoring to assess results and consider remedial measures when appropriate. To obtain Commission approval of contracts, utilities must disclose their LCBF evaluation of projects. Along with the Commission, parties monitor LCBF results. Parties may comment on advice letters, and make recommendations on approval or rejection of particular projects. The Commission will approve advice letters only for projects that have merit, and will reject advice letters seeking approval of contracts with Imperial Valley projects if they are unreasonable. Monitoring will not create undue pressure to select or approve bids when otherwise contrary to LCBF evaluation.

SDG&E says extensive resources in East San Diego County and Northern Mexico are facilitated by Sunrise and should not be ignored. CalWEA asserts that the specific monitoring, if adopted, should be expanded to include any bids for projects in the WECC system that would create significant flows on Sunrise. We decline to make this a requirement. CalWEA claims the power flows can be determined "using a simple shift factor calculation." (Sunrise Comments, at 6.) We are not convinced that such analysis is simple when there are many variables (e.g., number of projects, different sizes, different locations, varying on-line dates). The monitoring should initially focus on Imperial Valley projects. We encourage utilities, other entities and Energy Division to broaden the monitoring to include other projects when appropriate (e.g., when a project with a significant effect on the flow of power over Sunrise is sufficiently known relative to other projects).

4.3. Remedial Measures for 2010 Solicitation

We stated that if Imperial Valley projects resulting from the 2009 solicitation are not approved by the Commission prior to our approval of the 2010 RPS Procurement Plans that we will consider remedial measures for the 2010 Plans. We identified three:

- Require utilities to automatically shortlist all Imperial Valley proposals that are received in the solicitation so that the projects receive special consideration;

- Include an Imperial Valley bid evaluation metric in the LCBF methodology to give preference to Imperial Valley resources, and;
- Require each utility to conduct a special Imperial Valley RPS solicitation.

Several parties support some or all remedial measures if there are an inadequate number of Imperial Valley projects resulting from the 2009 solicitation. For the reasons explained below, however, we are persuaded by CalWEA, SCE and others that it is premature to adopt remedial measures now. We encourage parties to recommend remedial measures later if the 2009 solicitation produces an unacceptable result.

We decline to adopt remedial measures now because each of the three measures has the potential to conflict with the objectives of efficiency and selecting projects in LCBF order. Automatically shortlisting Imperial Valley proposals so that they proceed to contract negotiation may lead to inefficient use of limited utility and party time. Providing a preference for Imperial Valley resources (which is denied to others) generally conflicts with LCBF principles. An Imperial Valley-only solicitation provides no information about the cost and fit of non-Imperial Valley resources. It potentially handicaps the ability of IOUs and the Commission to select the optimal mix of resources from all bids, similarly violating the LCBF concept. Favoring development in one area undermines the fundamental objective of fair competition on a level playing field.

In its Sunrise comments, SCE states:

> The proper way to value the contribution of Sunrise to the viability of Imperial Valley projects is to appropriately value the transmission benefits of Sunrise, not to require selection of all Imperial Valley

> proposals or to artificially constrain competition. (Sunrise Comments, at 12.)

Reid supports this point saying:

> The proposals are unnecessary because Imperial Valley RPS projects already have a build-in advantage (access to transmission) in the contract evaluation process." (Sunrise Comments, at 7.)

We agree. Instead of limiting competition or creating a preference for Imperial Valley projects, the best approach is to allow the benefits of projects locating near approved transmission infrastructure to be considered within the LCBF analysis, similar to how SCE treats Tehachapi area resources. This approach considers the availability of and access to transmission, not simply the project's location within a geographic area.

Nonetheless, we will consider remedial measures if future evidence shows the LCBF methodology fails to properly value Imperial Valley resources and their unique access to transmission, or that there are other infirmities. Those measures might include automatic shortlisting, a special bid evaluation metric, special solicitation, or other remedies a party may propose. The expense and environmental consequences of Sunrise, just as with any significant infrastructure project, demand nothing less. We will not hesitate to use all regulatory tools at our disposal so that reasonable, cost-effective renewable resources enabled by Sunrise are developed. (*See* D.08-12-058, at 263.)

CEERT recommends that each IOU be required to report in its 2010 RPS Procurement Plan why Imperial Valley projects were not selected if such projects are bid into the 2009 solicitation but the contracts are not signed. We decline to make that order here because we expect this information to be collected by Energy Division, and be available to parties (subject to proper confidentiality treatment) as part of the Imperial Valley monitoring noted above. If it deserves additional treatment as part of the 2010 Plan review, the assigned Commissioner may elect to include this as a specific item when issuing the Ruling setting the schedule and details for the 2010 Plan.

While we decline to adopt a special solicitation only for Imperial Valley resources, we note that SDG&E is in a unique position. SDG&E committed, as a condition of the authorization to build Sunrise, to replace any currently approved renewable energy contract deliverable via Sunrise that fails, with a viable contract for electricity from a renewable generator located in Imperial Valley. This is important and binding. To honor this commitment, SDG&E says it is prepared to hold Imperial Valley-specific solicitations for replacement energy if a Commission-approved project to be carried via Sunrise fails to materialize.

SDG&E may conduct Imperial Valley-only solicitations or take other reasonable action to fulfill its commitment. We do not adopt any policies here which prevent SDG&E from doing so. SDG&E proposes to begin this process with an Imperial Valley-specific solicitation within its 2009 general RPS solicitation. We address this proposal below in the chapter regarding limited issues specific to each plan.

4.4. Project Viability Evaluation Methodology

We also identified four issues that more generally apply to renewable resource procurement throughout the state, but which could encourage the development of the most viable resources facilitated by Sunrise. These issues involve changes in rules and criteria regarding (1) contract failure, (2) assessment of continuing contract viability after contract approval, (3) assurance that projects with demonstrated indicia of viability are given appropriate weight, and

(4) milestone requirements along with provisions for credit, collateral and deposits to ensure selection of the most viable projects.

Energy Division staff quickly developed a proposal for unified treatment of these four issues via a Project Viability Evaluation Methodology. The proposal involves three key components of the RPS Program:

- Procurement process,
- Commission process for contract review and approval, and
- Flexible compliance provisions.

We address each of these three key components in turn and, for the reasons discussed below, we adopt the Energy Division staff proposal in part.

4.4.1. Procurement Process

Staff makes three proposals regarding the procurement process: (a) standardized methodology and criteria to assess project viability, (b) increased transparency regarding an IOU's project viability assessment, and (c) linking project viability and development security. We address each in order.

4.4.1.1. Standardized Methodology

Staff proposes that the IOUs employ a standardized methodology to assess the viability of each proposed project. The proposed methodology uses a minimum set of criteria, and the criteria are weighted to calculate a total project viability score. The tool is referred to as the Project Viability Calculator.

In comments, parties generally support using a standardized project viability methodology and calculator. Parties argue, however, for more individualized treatment, non-binary weighting factors, and the use of the project viability calculator as a screening and indicative (not dispositive) tool. We first put the proposal in perspective by examining the current consideration of project viability in the review of bids.

Each IOU now includes project viability assessment as part of its LCBF methodology.[15] The categories and criteria are not uniform, however, and the weighting (if any) of individual criteria is not entirely clear. Energy Division considers project viability in its evaluation of advice letters seeking approval of contracts. In particular, Energy Division requires each utility to use a specific template when submitting an advice letter. The template for the 2008 RPS solicitation includes a project viability matrix, which is substantially similar to the project viability calculator.[16]

We agree with staff and parties that the current project viability assessment tools can be improved by adopting a requirement for a more transparent and uniform approach. Among other things, this will increase the public's confidence that projects with demonstrated indicia of viability are given appropriate weight.

Therefore, we require that each IOU include a project viability methodology and calculator in its amended 2009 Procurement Plan and

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[15] For example, PG&E assesses project viability using two categories: (a) project status (including 16 criteria) and (b) technology viability and participant experience (including eight criteria). (PG&E Solicitation Protocol, Attachment K, Section II.B.4.) SCE assesses project viability using three categories: (a) seller's capability to perform (with four criteria), (b) technical viability (with three criteria) and (c) project viability (with seven criteria). (SCE Procurement Plan, Appendix B, at B-5 to B-6.) SDG&E assesses project viability using four categories: (a) project status (with seven criteria), (b) transmission availability (with three criteria), (c) technology (with seven criteria), and (d) developer experience (with three criteria). (SDG&E Plan, Appendix C, at 4-5.)

[16] The project viability matrix has three key categories, and essentially uses binary scores for each of 13 criteria, totaling to a final result in the range of 0-15. The project viability calculator also has three key categories, and essentially uses binary scores for each of 14 criteria, totaling to a final viability score in the range of 0-17. (*See* February 3, 2009 ACR, Attachment B, for the project viability calculator.)

solicitation package filed pursuant to this order. The project viability calculator should contain at least three separate, major categories: (a) developer experience; (b) technical viability; and (c) development milestones. Within each category, the project viability calculator must contain criteria used to measure and evaluate the category.[17] The criteria should be specific and exactly stated because, as DRA and others correctly point out, the criteria can otherwise be vague and subject to interpretation. Thus, definitions or descriptions of each criterion must be included in the solicitation documents in order to minimize ambiguity while increasing understandability and transparency in the use of this tool. We agree with CalWEA and others that the scores for each criteria should not be binary (e.g., 0 or 1), but should be in a range (e.g., 1 to 10).

Subsequent to the February 3, 2009 ACR, Energy Division has refined its proposal based on parties' comments, held a workshop, and taken another round of comments. Parties and staff have continued to develop the calculator. We appreciate this effort to respond expeditiously to the Sunrise order. Energy Division will conclude its work shortly, and serve the final product for use in the 2009 solicitation. IOUs should include the final calculator in their amended 2009 Procurement Plans and solicitation materials. This will permit bidders to understand one of the important tools that will be used in the LCBF assessment of bids. It will also provide a uniform approach so that over time we can assess how well this tool is working.

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[17] For example, criteria for developer experience might include experience with projects, financing, ownership and operations; criteria for technical viability might include technology development; criteria for development milestones might include site control, permitting, and interconnection progress.

While we expect the project viability calculator to be a useful tool, we also acknowledge the comment of PG&E that the project viability calculator "attempts to predict a qualitative state." (Sunrise Comments, at 10.) This is echoed by SCE, who says there "is no perfect project viability calculator that will determine whether a project will ultimately come on-line." (Sunrise Reply Comments, at 8.) The project viability calculator seeks to create a numerical score for a future event (i.e., project success) that involves judgment (e.g., assessing the relative amount of developer experience) and may include predicting the future outcome of numerous variables (e.g., if a permit is granted). It cannot, and we do not expect it to, perfectly predict the future. Moreover, parties correctly point out that the project viability calculator score is measured at a moment in time, but may change (for better or worse) with the passage of time.

Thus, we agree with PG&E and other parties that the project viability calculator is to be used as a screening tool, not to determine the exact merit of a particular project or contract. The output of the project viability calculator should be just one factor in the evaluation of projects for LCBF ranking. Utilities ultimately remain responsible for the recommendations they make regarding projects to meet their RPS Program targets.

We adopt the project viability calculator as a useful tool promoting increased transparency, consistency and objectiveness in the initial selection process. At the same time, we note that unless the score is updated as the project is developed, the project viability calculator will not fully address the second issue identified by the Commission (i.e., assessment of continuing viability after contract approval). The project viability calculator may or may not be the best or only tool to assess projects in the development queue. For example, there are already contract provisions that address project delays or failures. We encourage staff and parties to give further consideration to assessment of continuing project viability after contract approval, and to make relevant recommendations to improve program results, when appropriate.

In comments on the proposed decision, SCE and PG&E argue for allowing each IOU to further modify the final staff methodology and calculator. We clarify that we expect each IOU to use the staff final product in its amended 2009 RPS Procurement Plan without further amendment but applied within the guidelines provided by staff. For example, the final staff product may allow IOUs to set category weighting factors as long as the factors sum to 100%. IOUs may not add a category and may not change or delete criteria within a category, but the final staff product may allow an IOU to add criteria within a category. This approach reasonably balances the benefits of the project viability tool being transparent and uniform (thereby increasing the public's confidence that projects with demonstrated indicia of viability are given appropriate weight) with the ability of each IOU to apply unique elements, if necessary and appropriate. This allows California to gain experience with an essentially uniform tool while permitting room for limited unique application. This is a proper balance given that the calculator is a screening, not dispositive, tool while permitting room for judgment. We will consider further refinements over time as necessary.

4.4.1.2. Increased Transparency Regarding Assessment of Bids

Staff proposes changes designed to increase the transparency of an IOU's assessment of project viability. In particular, staff proposes that certain project viability data be identified in public versions of advice letters, along with the Report of the Independent Evaluator (IE). Staff would require additional project viability data to be included in the confidential version of the IE Report. Parties generally do not oppose increased transparency, but disagree on what should be made public. For the reasons explained below, we adopt part of the staff proposal.

We direct that each contract submitted for approval by advice letter contain in the public version of the advice letter certain aggregate results for the solicitation as a whole. The results are to be solicitation-wide, not project specific, for the solicitation from which the particular project emerged. The reportable aggregate variables are to be identified by Energy Division, and should be included in Energy Division's template. For example, they may include minimum, maximum, mean and median results for (a) the total project viability calculator score and (b) each specific criterion within the project viability calculator. We are convinced by staff and others that this will increase the transparency of project viability as measured overall in the market, and provide benchmarks against which project-specific results may be judged.

We are convinced by SCE and others, however, that project-specific information must not be made public. We have directed that result in our confidentiality decision. (D.06-06-066, Appendix 1, Item VII.G (Score Sheets) and Item VIII.B (Specific Quantitative Analysis of Bids).)

Nonetheless, we agree with staff that project-specific project viability information should be included in the confidential appendices to advice letters and validated by the IE in the confidential versions of IE reports. Moreover, upon request from Energy Division, we expect each IOU to provide project viability scores for each project bid into a solicitation, with an explanation of why projects with high project viability scores did or did not make the shortlist. We need not make that order here, but Energy Division may solicit the data when and as needed, and IOUs must comply.

4.4.1.3. Linking Project Viability Score and Development Security

Energy Division proposes that development security be linked to the project viability score. In this way, projects that are determined to be highly viable would pay a reduced development security cost, while less viable projects would pay a higher development security. This provides an incentive for projects to increase their viability, thereby promoting an increase in the overall success of the RPS program.

Staff correctly identifies one important relationship with regard to development security. Nonetheless, for the following reasons we decline to adopt this approach.

Deposits, and development security in particular, serve several purposes and balance many competing interests.[18] For example, SCE points out that one important function of development security is to offset the replacement costs of a failed project. SCE states that projects with different viability scores but similar output characteristics (e.g., capacity, energy, on-line date) have similar replacement costs. For the purpose of offsetting replacement costs, SCE's example supports the assessment of similar development security even if the project viability scores are different.

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[18] The competing interests include "the desire to stimulate the RPS market; the interest of ratepayers and the state in having viable projects bid, develop and operate in a reasonable, reliable and safe manner; and a reasonable balance of risks between all parties." (D.07-02-011, at 19.)

PG&E says the staff proposal should be rejected:

> … because it does not properly address the purpose of project development security. After a PPA [Power Purchase Agreement] has been signed, the purpose of the seller's security is to encourage the development to reach commercial operation date and deliver on schedule. It does this by creating a financial incentive to discourage the seller from pursuing an economic alternative to performing under the PPA. Under the Staff's formula, the more viable the project, the lower the security. The formula makes it easier for highly viable projects to breach their PPAs, if the market price for renewable power increases, and subsequently sell their power elsewhere." (Sunrise Comments, at 13.)

That is, development security not only addresses replacement costs, it creates financial incentives for desirable results beyond project viability. We agree that this can also be an important function.

Even if we set aside these two factors (i.e., replacement cost and financial incentives) and focus only on project viability, we lack data on the degree to which project viability is materially changed based on changes in development security. Moreover, as noted above, the score from the project viability calculator is indicative, not determinative. We hesitate to adopt a precise relationship based on a qualitative tool.

Nonetheless, the concept in general has merit and may be applied within our current structure. That is, development security is a negotiable term.[19] Projects with high viability may seek a reduced development security. If reasonable, the IOU may agree, and the Commission may approve an advice

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[19] The Commission specifically identifies four terms as non-modifiable. (*See* D.08-04-009.) The remaining terms are modifiable, including credit, deposit and collateral.

letter with this provision in the proposed contract. This reasonably meets the underlying objective (i.e., providing an incentive for projects to increase their viability, thereby increasing the overall success of the program). On the other hand, a project with low viability may voluntarily propose to increase its development security as a method to increase its attractiveness compared to other projects. If reasonable, the IOU may agree, and the Commission may approve an advice letter. This relationship may also be captured in the project viability calculator. It may provide a powerful way for some projects to proceed when they might otherwise not be selected, while at the same time providing an offset for replacement costs or compensation to ratepayers if the project fails. We encourage parties to work with Energy Division staff to explore this further.

Finally, SCE points out that development security is not a significant barrier to project development. In support, SCE cites a CEC report which identifies eight primary factors in the failure of renewable energy projects, none of which were related to development security.[20] IEP (representing RPS projects) says: "deposit provisions do not appear to be the problem." (Sunrise Comments, at 14.) We expect deposit amounts and policies to be subject to change over time based on changing market conditions, including barriers to entry. (D.07-02-011, at 19.) We do not oppose reasonable changes to deposit amounts and policies. Under the right conditions, it may be reasonable to modify development security to increase its relationship with project viability.

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[20] SCE Sunrise Comments, at 17, citing "Building a 'Margin of Safety' Into Renewable Energy Procurements: A Review of Experience with Contract Failure," at 24-25, CEC-300-2006-004 (January 2006).

Our current approach is sufficiently flexible to allow application of the staff's proposal. We need not adopt anything more specific at this time.

4.4.2. Commission Review and Approval of Contracts and Amendments

Staff proposes that contracts be placed in one of three categories based on project viability score.[21] In the lowest project viability category, contracts would not be considered for approval. In the middle project viability category, contracts would be considered for approval but only limited contract amendments would be considered. In the highest project viability category, contracts would be considered for approval and major amendments would be considered. Staff says this approach will increase transparency, increase uniformity in the process, and ensure that projects with demonstrated indicia of viability are given appropriate weight. In summary, the proposal is:

Line No.	Category (Project Viability Score)	Eligible for Commission Approval	Contract Amendments Permitted
1	A (low score)	No	Not Applicable (underlying contract not approved)
2	B (medium score)	Yes	Limited amendments permitted
3	C (high score)	Yes	Major amendments permitted

We decline to adopt this proposal. We are convinced by many parties that the project viability calculator needs further development and testing before it is

[21] The proposal primarily focuses on projects that rely on commercially demonstrated technologies. As proposed, the rules may not apply to projects using an emerging technology.

adopted for such a strict, serious and final purpose. For example, we agree with DRA that "the PVC [project viability calculator] is not developed sufficiently at this time to serve the purpose of invalidating bids." (DRA Sunrise Comments, at 6.)

We also are disinclined to adopt a tool that limits our discretion to consider a range of projects. For example, in recommending against a minimum project viability calculator score for Commission approval, DRA convincingly states:

> The PVC [project viability calculator] score is only one element of the LCBF methodology, and to the extent that other factors weigh into that assessment, the PVC alone should not override all other considerations. The reality is that less viable contracts will be disfavored in the LCBF process even without setting a threshold PVC score." (Sunrise Comments, at 6.)

In its objection to a rigid requirement that contracts have a minimum score to justify Commission approval, PG&E correctly says:

> It would be imprudent to automatically reject any PPA that does not meet the minimum project viability score because other benefits of the PPA may outweigh its viability risk." (PG&E Sunrise Comments, at 14.)

For the same reasons stated above, we similarly decline to adopt related rules regarding contract amendments.[22]

4.4.3. Flexible Compliance Provisions

Finally, staff proposes to align flexible compliance rules with project viability, thereby assisting the Commission determine the reasonableness of a

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[22] We may still deny an amendment (e.g., a requested price increase for a project with a medium project viability score) but decline to make that outcome automatic by denying the project the ability to seek our consideration of an amendment.

utility's request to use flexible compliance. In particular, since projects in Category A already face significant development risk, staff proposes that such projects not be eligible to be used for flexible compliance (e.g., may not be used to defer a deficit due to seller non-performance). Staff proposes that projects in Categories B and C may cite seller non-performance as a basis for deferring a deficit. Among other reasons, staff asserts that aligning the use of flexible compliance with project viability increases the incentives for utilities to do the best possible job of screening and selecting the most viable projects.

Some parties support and others oppose this proposal. We decline to adopt this proposal at this time. The score from the project viability calculator is not necessarily a precise or exact predictor of outcomes. Also, flexible compliance provisions are already quite complicated. We decline to make them even more complicated for a modest increase in incentive to select viable projects. A brief background on flexible compliance helps put this in context.

Utilities are required each year to procure an APT, with the APT growing each year by the IPT, and equaling 20% by 2010. Flexible compliance provisions allow some leeway in meeting each APT, and the 20% by 2010. These provisions include the banking of surpluses for later use, and the allowance of a deficit for up to three years. Our rules for deficit allowance permit a retail seller to:

1. defer up to 100% of its IPT (for the first year in which the retail seller has an IPT) for up to three years without stated reason,
2. defer up to 0.25% of its prior year sales for up to three years after the year of the deficit without stated reason, and
3. carry a deficit greater than 0.25% of prior year sales for up to three years after the year of the deficit upon a convincing showing, which may include the following:
    a. insufficient response to a solicitation,

b. contracts already executed will provide future deliveries sufficient to satisfy current year deficit (earmarking),
c. inadequate public good funds to cover above-market costs,
d. seller non-performance,
e. lack of effective competition,
f. deferral promotes ratepayer interests and RPS objectives,
g. insufficient transmission, or
h. showing of other good cause.

Within this framework, utilities already have substantial incentive to select viable projects. Flexible compliance provides flexibility within a window of time, but inadequate procurement in one year may be deferred "to no more than the following three years." (§ 399.14(a)(2)(C)(i).) A deficit thereafter is not excused as an element of flexible compliance protocols.

We have made clear that success is not measured by contracts or promises but by actual deliveries of energy. Deficit deferral permitted for up to three years pursuant to flexible compliance provisions must ultimately be filled by actual deliveries no later than at the end of three years. Failure to do so exposes the utility to a penalty up to $25 million.[23] This gives each utility a strong incentive to select viable projects, but permits a three-year window to allow for various contingencies. Moreover, we have consistently stated that each utility must include a reasonable margin of safety in its procurement in order to build a buffer against contingencies, and should build and operate its own plants, if

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[23] *See*, for example, D.03-12-065, Attachment A at 52; D.05-07-039, Findings of Fact 12 and 13, Conclusion of Law 5 and Ordering Paragraph 13; D.08-02-008 at 17, 19 and 27, Findings of Fact 10 and 12, and Conclusion of Law 10.

necessary, to meet RPS Program targets. (*See*, for example, D.08-02-008, at 26, 32.)

UCS recommends that seller non-performance be eliminated as an excuse for deferring procurement deficits. According to UCS, the best and most straightforward way to promote program success is to ensure that compliance rules are aligned with incentives to procure the most viable projects. UCS recommends this be done by eliminating seller non-performance. We decline to make this change.

Seller performance is not certain, and it is reasonable to provide some measure of flexibility. At the same time, however, we have made no provisions for failure to reach program targets after the flexible compliance period. As a result, the existing penalties ultimately align flexible compliance with results, and provide substantial incentive for buyers to select viable projects.

Staff's proposal is creative. It seeks to reasonably build on the existing incentives for each utility to select viable projects. The probable benefits, however, do not at this time appear to outweigh the additional complexities and related costs. While we decline to adopt the proposal now, we welcome additional proposals from staff and parties that will continue to build proper incentives into the program. We especially invite additional comprehensive proposals that address the entire flexible compliance regime (not individual pieces), particularly if able to moderate (not exacerbate) program complexity.

5. Other Issues Common to All Plans

We address the following eight issues common to most if not all Plans:

- Exclusivity Agreement Date
- Tradable Renewable Energy Credits (TRECs)

- Standard Terms and Conditions 5 (STC 5) and 25-year Contract Term
- Network Upgrades
- LCBF
- TOU Factors
- Utility-Owned Generation (UOG)
- Data for 2010 Plans

5.1. Exclusivity Agreement Date

The Commission adopted a schedule for the 2008 solicitation that was limited to major milestones, thereby permitting IOUs and staff reasonable flexibility. (D.08-02-011, at 46.) The schedule included a date for each IOU to submit its shortlist to the Commission and the Procurement Review Group (PRG). The schedule did not address if and when IOUs may request or require a bidder to execute an agreement for exclusive negotiations. As the 2008 solicitation progressed, bidders of at least one utility asked for early notification of their shortlist status because they had been shortlisted by another IOU, and that IOU was requesting that the bidder agree to exclusive negotiations.

As a result of this situation, respondents and parties were asked to address the following question for the 2009 solicitation: "Should the Commission take a position on whether or not an IOU may execute exclusivity agreements with bidders prior to formal notification to all bidders?" PG&E and SDG&E encourage Commission adoption of a consistent schedule for all three utilities so that bidders will have approximately simultaneous information regarding their shortlist status before being required to agree to exclusive negotiations with only one IOU. SCE recommends the Commission focus on policy objectives and compliance requirements, letting IOUs separately decide details related to the competitive solicitation process and dates for exclusivity agreements. Sierra and PacifiCorp assert the issue does not apply to them.

In addressing this question, we first note that in 2004, the Commission adopted the following as part of the LCBF methodology:

1. All bids should be treated as potentially multiple until bids are short-listed and negotiations begin. (D.04-07-029, Ordering Paragraph 1, Finding of Fact 13.)
2. It is reasonable to require bidders that have been shortlisted to withdraw competing bids, to avoid the situation in which the utilities are negotiating against one another for the same project, potentially resulting in inflated prices. (D.04-07-027, Ordering Paragraph 1, Finding of Fact 11.)

That is, we determined that exclusivity is a reasonable requirement upon a bidder being shortlisted, but we did not establish a uniform date to trigger exclusivity. We are persuaded by PG&E and SDG&E to now adopt a uniform date before which an IOU may not request or require that a bidder execute an agreement requiring exclusive negotiation with an IOU. Experience from the 2008 solicitation shows that to do otherwise results in the need of one or more IOUs to accelerate their evaluations and notification process in order to compete for attractive RPS offers. This unreasonably places IOUs in a situation where another IOU can reduce the available time for reasonable review of all bids received by that IOU. PG&E's IE advises that it is desirable to avert premature shortlisting. We agree.

Moreover, we are persuaded by SDG&E that a non-uniform exclusivity date allows bidders to "game the system." As SDG&E argues, compressing pre-shortlist negotiations provides an opportunity for the bidder to extract concessions from an IOU in order for the IOU to obtain exclusive rights for further negotiations, raising the likelihood of a bidding war and unnecessary cost increases for ratepayers. Therefore, we adopt SDG&E's recommendation to prohibit execution of an exclusivity agreement with bidders before formal shortlist notification to all bidders.

SCE points out municipal utilities do not have the same procurement restrictions but they are formidable competitors. SCE says the option of when to execute an exclusivity agreement must be left to the IOU because IOUs are competing against many buyers, including municipal utilities.

We are not persuaded. Competition with municipal utilities was not what caused the problem in 2008. PG&E and SDG&E face the same concern as SCE but do not seek the same remedy. We adopt the recommendation of PG&E and SDG&E for the 2009 solicitation.

IOUs and parties may bring further information to our attention for consideration in the 2010 Plans. For example, at least in theory, a fully competitive market protects buyers and sellers without the need to limit competition via exclusivity agreements. Parties may wish to bring us further information on the vitality of the competition in the RPS market and, if sufficiently competitive, on the desirability of eliminating the use of exclusivity agreements altogether. Alternatively, additional experience with a uniform date between Commission-regulated entities relative to other competitors (e.g., municipal utilities) may provide useful insights into necessary changes here.

Finally, SDG&E recommends the specification of additional dates. In support, SDG&E says that prevention of inequitable pre-shortlist negotiations requires the date on which a bidder accepts its shortlist position to be (a) as close as possible in time to the shortlist notification date and (b) the same day for all IOUs.[24]

We decline to set a uniform number of days for a bidder to accept or reject its shortlist position, or a single such date for all IOUs. We did not specify that level detail for the 2008 Plans, and we decline to do so for 2009. We are not convinced that this level of flexibility between IOUs materially harms competition or unreasonably increases the bargaining position of any bidder. We continue to be persuaded of the need for reasonable flexibility, as argued by SCE and others. Each IOU may set its own time limit for the bidder response, as long as it is consistent with the adopted schedule for the overall solicitation.

5.2. TRECs

IOUs include discussion of the use of TRECs in their 2009 Procurement Plans, generally seeking use of TRECs but conditioned on a future Commission order authorizing that use. DRA and TURN recommend that the Commission reject inclusion of the use of TRECs in these Plans. In support, DRA and TURN cite the Commission decision on the 2008 Plans. We there declined to accept SDG&E's proposal to include TRECs in its discussion of flexible compliance. We did so noting that the treatment of Renewable Energy Credits (RECs) was being

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24 SDG&E proposes four weeks between the date SDG&E notifies short-listed bidders and the date short-listed bidders must withdraw from SDG&E's solicitation or accept short-listed standing and provide a development security deposit. (SDG&E Plan, at 7 of 26.) PG&E recommends eight days between the date PG&E notifies shortlisted bidders and the date the bidder notifies PG&E whether it accepts the shortlisted position. (PG&E Protocol, at 4.) SCE proposes ten days between the date SCE notifies a bidder of its short-list status and the date the bidder either withdraws its bid or grants SCE exclusive negotiating rights. (SCE Plan, at 14.)

addressed in R.06-02-012, and we did not want to prejudge the REC issue in the 2008 Plans. (D.08-02-008, at 18.)

Additional events have now occurred. We have adopted the final joint staff report of the CEC and this Commission on the CEC's RPS Tracking System, in which we find that the tracking system is ready to support the use of TRECs for RPS compliance.[25] (Resolution E-4178, November 21, 2008.) Also, a proposed decision on the use of TRECs has been prepared, and commented upon by parties.

Although our consideration of the use of TRECs for RPS compliance is further along than it was in early 2008, it is not yet complete. It would be premature to authorize IOUs' use of TRECs (even subject to conditions) until we have actually authorized the use of TRECs for RPS compliance. That subsequent authorization, for example, may include conditions we cannot foresee here.[26]

The IOUs should, therefore, remove discussion from the Amended Plans to be filed pursuant to this order regarding the use of TRECs to meet RPS Program targets. If and when we authorize the use of TRECs for RPS compliance, each IOU may amend its Plan in accordance with the authorization at that time.[27]

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[25] Our authority to authorize TRECs is conditioned upon this finding by the CEC and us. (§ 399.16(a)(1).)

[26] *See* § 399.16(a)(9).

[27] Each IOU may file and serve an advice letter notifying the Commission and the service list of a change in its RPS Procurement Plan. (*See* General Order 96-B.) The advice letter should attach the pages which are added to the Plan, and clearly identify any deletions or other changes to the Plan.

5.3. STC 5 and 25-Year Contract Term

Contract length (also called contract term) is Commission-adopted STC 5. (D.08-04-009, Appendix A, at 11.) As one of our STCs, we require that each contract specifically address this item. We provide model language, including that parties may select the term by checking one of four boxes. The boxes are for a contract term of 10 years, 15 years, 20 years, or non-standard delivery over a specifically stated period of years. STC 5 is modifiable by parties.

LSA and CalWEA propose that 2009 RPS Procurement Plans include an option for bidders to select a contract term of 25 years. As proposed, IOUs would not be obligated to enter into 25-year contracts, but would be obligated to include the option, consider bids with 25-year terms, evaluate those bids using the LCBF methodology, and justify rejection of such bids to the PRG. In its response, PG&E says it does not oppose the recommendation. SCE says the recommendation should be rejected.

We decline to adopt the LSA/CalWEA proposal. While STC 5 was previously non-modifiable, parties are now free to modify STC 5 during the solicitation/negotiation process. (D.07-11-025, at 20.) We see no need to modify an already modifiable term to include a specific reference to 25 years. Rather, as written, modifiable STC 5 allows the bidder to fill in the number of years it proposes for the sale. Thus, we are not persuaded that we should change STC 5 for all model contracts.

At the same time, we note that SCE's Request for Proposals states that:

> … sellers may propose a standard delivery term length of ten (10), fifteen (15) or twenty (20) years, or a non-standard delivery term that is no less than one (1) month and no longer than twenty (20) years. (Procurement Protocol, at 5.)

SDG&E's Request for Offers says a bidder shall propose a 10-, 15- or 20-year agreement; that SDG&E will accept proposed short term agreements of up to five years; and that SDG&E may (at its discretion) consider offers of other contract duration. PG&E's Solicitation Protocol says bidders may offer delivery terms as short as one month and as long as 10, 15 or 20 years, or any term that is mutually agreeable and approved by the Commission.

We know of no convincing reason why the bid request or protocol of any IOU should foreclose or discourage a bidder from submitting a bid in excess of 20 years.[28] Nor should the request or protocol suggest that an IOU may decline to consider such bids. We adopt market price referents (MPRs) in excess of 20 years. (*See* Resolution E-4214 dated December 4, 2008.) This provides a vehicle for consideration of such contracts. The comments of LSA/CalWEA demonstrate that some solar and wind projects may find contracts in excess of 20 years desirable. Those proposals should be allowed and considered.[29]

Therefore, we do not change STC 5, but we direct each IOU to exclude language in its request or protocol which would prohibit or discourage bids longer than 20 years. This requires changes in the language proposed by SCE and SDG&E, and perhaps PG&E.

We require this consistent with existing language in STC 5. That is, STC 5 permits a bidder to mark the box "non-standard delivery term" and enter a period longer than 20 years. This aligns with both a plain reading of STC 5, and

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[28] "In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than ten years in duration, unless the commission approves of a contract of shorter duration." (§ 399.14(a)(4).)

[29] Allowing and considering a proposal does not mean the proposal will be approved and become an effective contract.

the notion of STC 5 being modifiable. We expect each IOU to consider bids submitted for any duration, from one month to over 20 years. Just as with any bid, the IOU should evaluate each bid using its LCBF methodology plus any other reasonable screening tools, and discuss acceptance or rejection with its PRG, as appropriate.

5.4. Network Upgrades

LSA/CalWEA recommend the Commission encourage upfront funding by IOUs of network upgrades required for renewable generator interconnections. In support, LSA/CalWEA point out that Federal Energy Regulatory Commission's (FERC) policy is to require a renewable generator to fund the cost of network upgrades upfront if the Participating Transmission Owner does not undertake that responsibility itself, with the cost of the upgrade credited back to the generator over a subsequent five-year period.[30] LSA/CalWEA assert the Commission is aware that market failures and increased customer cost may occur due to FERC's policy, and to remedy these problems the Commission has provided "backstop funding." This approach allows an IOU to provide upfront funding of network upgrades and recover those costs from retail customers if FERC does not permit recovery through wholesale transmission rates.[31]

According to LSA/CalWEA, the Commission expected this funding approach to result in IOUs volunteering to build and pay upfront, in the majority of cases, for all transmission network upgrades needed to interconnect both

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[30] LSA/CalWEA Comments, at 7, citing *Standardization of Generation Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003).

[31] *Id.*, citing Pub. Util. Code § 399.25 and Commission D.06-06-034 (at 11, 38, and Conclusion of Law 3.)

individual and multi-developer projects. LSA/CalWEA claim this expectation has not been realized, and that this could result in a stunted market. LSA/CalWEA propose three remedies. PG&E and SCE oppose the proposals. We adopt them in part.

5.4.1. Cash Flow

First, LSA/CalWEA suggest that the Commission renew its support for IOU-funded network upgrades, and its commitment to ensuring cost recovery for IOUs. In particular, LSA/CalWEA recommend the Commission allay IOU concerns about cash flow impacts by adopting policies to minimize regulatory lag related to cost recovery (e.g., allow IOU cost recovery pending FERC approval of cost recovery in wholesale rates; use Commission-authorized balancing accounts to speed rate adjustments).

We decline to make changes here. We are giving further consideration to these issues in our transmission rulemaking and investigation (R.08-03-009/ Investigation 08-03-010). We are there considering policies that would actively promote the development of transmission infrastructure to provide access to renewable energy resources for California. We encourage LSA/CalWEA and other parties to participate.

5.4.2. Component of Plan

Second, LSA/CalWEA suggest that the Commission encourage each IOU to include upfront funding as a component of its 2009 RPS Procurement Plan. We do not disagree. To the extent not already addressed but intended as a component of its 2009 RPS Procurement Plan, each IOU may include upfront funding of network upgrades in the revised Plans to be filed shortly after this decision.

5.4.3. Justify Decisions

Lastly, LSA/CalWEA suggest that the Commission require IOUs to justify decisions to forego upfront funding in connection with any failure by an IOU to reach RPS Program targets. We decline to adopt this suggestion. SCE correctly points out each IOU is already on notice of its ultimate responsibility for reasonable RPS outcomes, within application of flexible compliance criteria. [32] Moreover, we have identified related issues in our transmission rulemaking and investigation. To the extent appropriate and addressed by parties, we will explore the matter there.[33]

5.5. LCBF Proposals

IOUs were asked to identify modifications in how bids are to be evaluated and ranked using their LCBF methodology between their 2008 and 2009 solicitations, including evaluation and ranking of out-of-state resources and short-term contracts. IOUs describe several modifications. Parties offer comments along with related proposals regarding project evaluation. For the reasons discussed below, we accept most proposals and decline to accept others.

PG&E reports that it will continue the ranking process implemented in 2008 but, based on IE feedback, clarifies the LCBF evaluation process with respect to three items. First, locational marginal pricing multipliers based on data developed by the California Independent System Operator (CAISO) will be used to evaluate delivery points. Second, PG&E makes explicit in its LCBF

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[32] SCE Comments on Proposed Decision, at 9.

[33] The issues in the preliminary scoping memo include: (a) has the Commission's cost recovery regime been effective in supporting transmission to renewable resource areas and (b) how could that cost recovery regime be improved. (R.08-03-009/I.08-03-010, at 8.)

protocol that PG&E will limit the total supply shortlisted from any single counterparty in order to diversify risk. Third, hybrid offers (a combined fossil and renewable proposal) must separately price the renewable power, and only the renewable power will be considered in the RPS solicitation.[34]

SDG&E says its LCBF method will reflect four changes. First, it will modify how it applies duration equalization adders (to equalize bids with different starting dates and terms). SDG&E says it will fill in delivery gaps using average 2009 bid prices rather than MPR (since MPR does not, according to SDG&E, include the REC component otherwise potentially contained within bid prices). Second, SDG&E says the roles and responsibilities for two separate bid assessment teams (Processing Team and Evaluation Team) will be combined into one team, aliases will no longer be created to disguise affiliate offers, and other information in an offer from an affiliate will no longer be masked. Third, SDG&E may seek outside consultants to perform LCBF quantitative calculations, depending upon internal resources, the number of offers and other related factors. Fourth, SDG&E proposes different methodologies for evaluating short-term and long-term offers.[35]

SCE does not identify any important, specific changes. SCE states that it has revised certain language.[36] SCE reports that it used the same evaluation

[34] As explained by PG&E, separate pricing is not required if 100% of the generation is RPS-eligible under the CEC's eligibility guidelines. It is required only when part of the generation is not RPS-eligible. (PG&E Reply Comments on the proposed decision, at 5.)

[35] *See* SDG&E Plan at 10, 18, and Appendix E, at 1, 2.

[36] SCE notes that the revisions are identified in the redlined comparison between its 2008 and 2009 LCBF written report. (S*ee* SCE RPS Procurement Plan, Attachment 1-2, Appendix B.)

methodology in 2008 for short-term and long-term contracts, and will do so again in 2009. SCE also explains that its methodology for evaluating and ranking out-of-state resources for 2009 is unchanged from that used in its 2008 Plan.

No party convincingly argues against these specific changes (discussed more below), and we accept them. Each IOU should continue to work with Energy Division and parties to make its LCBF analysis clear, as described more below. IOUs remain responsible for meeting RPS goals (e.g., 20% by 2010), and are expected to continue to modify and improve LCBF methodologies, if and as necessary, consistent with meeting program goals and complying with Commission orders.

Parties also make several proposals. LSA/CalWEA recommends that the Commission establish a process for improving consistency and transparency of the criteria IOUs use in evaluations of project viability. We have addressed this above regarding Sunrise issues.

LSA/CalWEA also recommends that the Commission require IOUs to explain the application of project viability evaluation criteria to UOG. We agree. The project viability methodology and criteria addressed above are focused on merchant plant. While the exact same methodology may not apply, we expect project viability considerations to be addressed whenever a UOG project is formally proposed by an IOU.[37]

Reid makes several comments relative to project evaluation under the heading of transparency. We decline to adopt Reid's recommendations.

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[37] This would not necessarily be part of an IOU's RPS Procurement plan but would, for example, be in the IOU's formal application with the Commission for a CPCN. If an

Footnote continued on next page

Reid is concerned with PG&E's use of qualitative assessments as part of its bid evaluation. To partially address this concern, Reid recommends the use of commercially available software to assess, and quantify, the probability of default as part of the credit attribute item in bid evaluation. PG&E points out in its response that this software typically requires the use of historical prices of the debt and equity of the firm and, for small and/or private firms that often bid into PG&E's RPS solicitation, this information is not available to PG&E. We are persuaded by PG&E that the required data is not necessarily easily available on an equal and unbiased basis. We decline to order IOUs to use such software. Nonetheless, the concept of quantifying and more objectively assessing the probability of default has merit. We encourage parties to continue to explore the subject and bring us additional proposals if and when reasonable.

Also, it is unclear how Reid's comments relative to portfolio fit and other items are to be incorporated into the LCBF methodology. We welcome further suggestions from parties. We encourage parties to clearly explain and support proposals, and then link specific recommendations to prior Commission orders or specific items in an IOU's Plan so that we may have a better opportunity to understand and implement reasonable proposals.

5.6. TOU Factors

RPS Plans include time-differentiation of prices to be paid for electricity generated by renewable resources. The time-differentiation is based on TOU factors.

IOU (or affiliate) submits a bid in an annual RPS solicitation, it would be in the review of bids in that solicitation.

CCC and Solar Alliance recommend the Commission direct IOUs to file benchmarking studies and schedule a workshop with an opportunity for written comments. We decline to do so. Parties have had time to engage in discovery, move for hearings, and bring evidence to the Commission, thereby making the record any party believes necessary. We will use the record before us.

CCC/Solar Alliance question why the summer on-peak TOU factors vary so widely between SCE, PG&E and SDG&E, with, for example, the summer on-peak TOU factor of SCE being 91% higher than that of SDG&E.[38] CCC/Solar Alliance contend this may be because the SDG&E factor is energy-only and is not "all-in" (capacity and energy).

There may be several reasons the TOU factors differ between IOUs. For example, the SCE summer on-peak period is June through September for 510 hours, while the SDG&E summer on-peak period is July through October for 696 hours, or 37% more hours for SDG&E than SCE.[39] There may be other factors.

CCC/Solar Alliance do not provide adequate evidence or argument to conclude that SDG&E's approach is flawed, even if different than that of PG&E and SCE. We encourage parties to provide further information, as appropriate. In the meantime, we have found that each IOU may develop its own TOU

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[38] The SCE summer on-peak TOU factor is 3.13. The SDG&E summer on-peak TOU factor is 1.64. The ratio (3.13/1.64) is 1.91.

[39] June through September is 85 days (excluding two holidays), at six hours per day during the on-peak period for SCE, for 510 hours. July through October is 87 days (excluding two holidays), at eight hours per day during the on-peak period for SDG&E, for 696 hours. The ratio of 696/510 is 1.365. (*See* SCE 2009 RPS Procurement Plan, Attachment 2-3, Exhibit K; SDG&E 2009 RPS Procurement Plan, Appendix B5, at 39.)

factors, in order to best reflect each utility's market-based valuation of electricity in different time periods. (D.06-05-039, at 68.) We continue this approach, absent compelling evidence to adopt a uniform method or benchmarking system.

We also expect time of use factors to "recognize the extent of the need for additional capacity." (D.06-05-039, at 69.) SDG&E must make a showing when it next addresses TOU factors that explains the reasonableness of its TOU factors. In particular, SDG&E must explain the extent of its need for additional capacity and how that is or is not reflected in its TOU factors. SDG&E must also present both energy only and all-in factors with its next showing so we have a more complete record upon which to reach an informed decision.

Here, however, we have no evidence to order different TOU factors. We are confident that parties with a sufficient economic interest will pursue these matters when it is reasonable for them to do so. We have committed to a formal review of TOU factors in the next long term procurement plan (LTPP) proceeding. (*See* D.08-07-048.)

Finally, CCC/Solar Alliance ask if the review of TOU factors in the next LTPP proceeding will modify the TOU factors used for RPS bids and the MPR in 2009 or 2010. No party, including CCC/Solar Alliance, makes a proposal to answer that question, and we will not craft one here. Therefore, we expect to apply TOU factors on a going forward basis. This will include current and prospective (but not retroactive) application of TOU factors determined in the LTPP proceeding to RPS Plans under consideration at that time. It will not include adjusting TOU factors accepted here for the 2009 Plans.

5.7. Utility-Owned Generation

We have consistently said that enforcement of the 20% by 2010 requirement will take into account whether or not each IOU undertook all reasonable actions to comply, including the building, owning and operating of its own RPS resources.[40] We asked that RPS Plans include a showing on IOU consideration of this option. The most recent Amended Scoping Memo asked that the Plan identify specific projects under consideration, and specific generic additions. Each IOU Plan includes its showing. (*See* Attachment C.)

DRA recommends that IOUs be directed to re-file their Plans in order to include cost-competitive UOG renewable projects. We decline to require the re-filing of Plans before reaching today's decision. Rather, we note that IOUs have included relatively more information in these Plans than before. For example, PG&E discusses small hydro, solar and other options. SCE includes its Solar Photovoltaic Program. SDG&E includes 20 MW to 35 MW of utility owned distributed solar project viability.

At the same time we point out, as we have before, that the showings are relatively short, generally inconclusive, and are unlikely to meet the necessary standard of demonstrating that the IOU undertook all reasonable actions to meet the 20% goal (if an IOU otherwise fails to meet that goal). (*See*, for example, D.08-02-008, at 32-33.) We repeat our prior statement on this matter since it remains reasonably succinct and clear:

> In particular, we note (as we similarly did last year) that minimal discussion in an RPS Plan about a utility building a renewable energy resource does not itself excuse an IOU from compliance with RPS goals. Our conditional acceptance of these Plans does not constitute a finding that each IOU has undertaken all reasonable actions to comply with RPS Program goals. We do not here require utilities to build resources. Nonetheless, we encourage IOUs to actively assess the feasibility of utility ownership, and pursue such

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[40] *See*, for example, D.06-05-039, at 33-34; D.07-02-011, at 23-25; D.08-02-008, at 32-35.

> ownership when and where it makes sense. We are unlikely to look favorably on a showing prepared in 2010, for example, regarding whether the IOU should have built plant earlier in the decade. Rather, we think the most convincing showing, if any, would likely include information created contemporaneously with each annual RPS Plan. (D.07-02-011, at 25, cited in D.08-02-008, at 33.)

IOUs may consider including more information in the amended Plans they file pursuant to today's order. This may include cost-competitive UOG renewable projects, as suggested by DRA.

We note that PG&E includes a new ownership option in its 2009 Plan. In particular, PG&E states that it has been approached by counterparties interested in pursuing joint development and ownership of projects. PG&E reports that its prior solicitations did not explicitly provide for this type of offer. PG&E says its 2009 Protocol has been revised to expand ownership options to include joint development and ownership (in addition to three previous options of (a) power purchase agreement with buyout, (b) purchase and sale agreement, and (c) site for development). No party filed comments.

We have long supported utility ownership in appropriate situations. PG&E's proposal is consistent with our guidance last year, wherein we expressed interest in the possibility of utility ownership of electric generation at the site of one of its customers, or partial ownership in combination with that customer. (D.08-02-008, at 34, footnote 14.) We are pleased to see PG&E include a joint development and ownership option this year, just as we were pleased in 2007 with a PG&E proposal to solicit sites for development. (D.07-02-011, at 24.) We accept PG&E's proposal, and encourage (but do not order) other utilities to adopt a similar item.

Finally, we have not only changed ratemaking treatment to place UOG on a more equal footing with others, [41] but we note that several very significant events have occurred since the draft Plans were filed in August 2008. Some of these are potentially so important as to dramatically change available options. Among these, for example, are: extension of certain federal investment tax credits for renewable resources to those owned or developed by utilities (where they were previously unavailable to utilities); reduction in interest rates; significant deterioration in financial markets; a national recession; and a $789 billion federal economic stimulus package that targets certain funds for renewable resources. The revised Plans filed pursuant to this order should include discussion of UOG, and other items, that reflect these important changes in conditions, where appropriate, in a manner consistent with Commission policies and guidance on procurement. This may include, for example, opportunities for utility procurement, where reasonable, of existing, completed merchant-developed RPS projects that are facing asset liquidation.[42] As we have said before, we expect utilities to reach RPS Program targets (e.g., 20% by 2010). If this is not possible through competitive solicitations, we expect utilities to reasonably develop all economic and feasible RPS plant necessary to reach Program targets. In the unique circumstances in which California finds itself today, that might also include a utility obtaining a partly completed RPS plant if

[41] *See* D.07-12-052, at 221 and Ordering Paragraph 33. Also *see* D.08-02-008, at 34.

[42] We addressed this, for example, as a situation that may result from a settlement or bankruptcy. We said in 2007 that we thought these conditions would diminish over time. (*See* D.07-12-052, at 212.) We now note that extraordinary and dramatic economic events since 2007 may affect the duration and nature of those situations.

a merchant generator is unable, or does not desire, to bring the project to completion.

5.8. Plan Organization and Data for 2010 Plans

As we have said in each of the last several years, we continue to note that each Plan is complex, with many attachments that are not easy to assess and use. (See, for example, D.08-02-008, at 35-38.) In particular, the form and format of the attached solicitation documents (e.g., Protocol, Request for Proposal (RFP), Request for Offer (RFO)) differ between IOUs, as do the various related forms and model contracts. We are not convinced that such complexity is necessary, and we encourage IOUs to continue to seek incremental improvements. We also suggest IOUs begin coordinating now on the form and format of the 2010 Plans. Increased coordination will promote the continuation of incremental improvements.

We are encouraged by progress made so far. For example, SCE proposes standard contracts for all RPS projects (discussed more below). We encourage increased standardization in form and format to the fullest extent reasonable. As we said last year:

> … the additional time spent 'up front' should be small compared to the time savings for the entire remainder of the process, including the Commission's time in reviewing endlessly different contracts. Additional uniformity will make the overall RPS structure more transparent, efficient and competitive. It may also promote desirable simplicity in a relatively complex Program. (D.08-02-008, at 38.)

IOUs make various recommendations on data and presentations for the 2010 Plans. For example, IOUs must provide information that identifies changes between Plans, including proposed changes to STCs. SDG&E and others state that the matrix used to identify proposed changes to STCs is burdensome.

SDG&E recommends that in the 2010 Plan each IOU simply provide redlines of changes to modifiable STCs, including justification for the change, along with a statement that no changes have been made to the non-modifiable STCs.

We agree with making improvements for the 2010 Plans that ease the workload on all parties while providing necessary information in an easy to understand format. We do not micromanage the details here. Utilities may work with Energy Division staff and parties on that goal for the 2010 Plans. The assigned Commissioner will issue an Amended Scoping Memo later in the year detailing the necessary items for the 2010 Plans. To the extent further refinements should be considered that are not already incorporated in the Amended Scoping Memo, utilities may also move at that time for changes to the Amended Scoping Memo.

6. Limited Issues Specific to a Plan

We comment here on limited issues specific to each Plan. As we have said before, conditional acceptance of these Plans does not constitute endorsement or adoption of proposed policy measures that have not yet been fully vetted. It also does not constitute endorsement or adoption of each aspect of each Plan.[43] Rather, we conditionally accept each Plan, subject to limited required amendments and several suggestions made herein. Each utility remains ultimately responsible for proposing and executing reasonable Plans that achieve RPS targets, including 20% by 2010, subject to flexible compliance rules. We will later judge the extent of each IOU's success, including the degree to which each IOU implements Commission orders, applies the Commission guidance,

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[43] *See*, for example, D.06-05-039 (at 61-62), D.07-02-011 (at 53) and D.07-012-052 (at 299, Conclusion of Law 63).

demonstrates creativity and vigor in program execution and, most importantly, reaches program targets and requirements.

6.1. PG&E

We limit our comments to three elements of PG&E's Plan: pilot program for pre-approvals, development security, and other changes.

6.1.1. Pilot Programs for Pre-Approvals

PG&E proposes a pilot program in which contracts meeting certain guidelines would be pre-approved by the Commission. The guidelines would include that the contract not modify the Commission-approved model contract in the 2009 Plan, the price be at or below MPR, this be a pilot program limited to 800 GWh, and contracts would be submitted to the Commission by Tier 1 advice letter.[44]

DRA, Reid, and TURN urge that the proposal should be rejected. They argue that the proposal is too large; the Commission lacks standards for evaluating the proposal; and the contracts under the program would not receive effective Commission review.

These disputes will not be resolved here, but in a separate proposed decision that addresses the streamlining of RPS contracting. PG&E's proposal has several elements that overlap with proposals for streamlining contract review processes that were being considered in R.06-02-012 and have now been transferred to this proceeding.[45] All these related issues will be considered in a separate proposed decision. PG&E's proposal is therefore not accepted as part of

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[44] *See* General Order (GO) 96-B regarding Tier 1 advice letters.

its 2009 RPS procurement plan and should be removed from the Amended Plan to be filed pursuant to this order. If some or all elements of PG&E's proposal are ultimately approved, PG&E may further amend its 2009 Plan at that time.[46]

6.1.2. Development Security

PG&E proposes to increase project development security amounts. In exchange, PG&E will, in certain situations, limit damages PG&E may collect when there is a default prior to commercial operation.[47] In summary, the proposal is:

Date Due	**Project Development Security**	
	2008	**2009**
Date Agreement Executed	$3/kW	$15kW
30 Days After Commission Approval	$20/kW[1]	$100/kW[1]

[1] For all products other than dispatchable, the $/kW amount is multiplied by the greater of (a) the capacity factor or (b) 0.5.

Default damages are calculated in both 2008 and 2009 by estimating the difference between the value of the contract and the cost of its replacement.[48] For 2009, PG&E will limit default damages during project development to the

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45 *See* Assigned Commissioner's Ruling Transferring Consideration of Certain Issues from Rulemaking 06-02-012 to Rulemaking 08-08-009 (April 3, 2009).

46 If unable to include the provisions within the amended Plan to be filed pursuant to this order, PG&E may later file and serve an advice letter to amend its Plan. (*See* GO 96-B.)

47 The security amounts increase upon commercial operation, but PG&E does not propose any change here between its 2008 and 2009 Plans.

48 *See* § 5.3 (Calculation of Termination Payment) in PG&E's model contract for both 2008 and 2009. The amount "shall not include consequential, incidental, punitive, exemplary, indirect or business interruption damages." (§ 5.3 of PG&E model contract.)

amount of the project development security in three cases. The cases are when the developer is unable to construct the project due to the developer's inability to (a) obtain necessary permits, (b) obtain transmission upgrades or (c) overcome a force majeure event.[49]

In support, PG&E says this responds to bidder feedback. According to PG&E, counterparties have expressed a willingness to pay higher deposits in exchange for knowing the extent of potential damages upfront. PG&E says this facilitates project financing. PG&E explains that it also helps ratepayers by providing sellers a potentially stronger incentive to complete projects, since sellers have more money on deposit with PG&E that PG&E will keep in the event of default. PG&E reports that the modified requirement is also similar to the credit requirements covering project development for the 2008 long-term request for offers. No party comments in support or opposition.

We accept PG&E's proposal. In doing so, we note that the higher security amounts are due in all cases, even those other than the three instances wherein the damages are limited to the security deposit. By increasing costs, this may generally act as a constraint on projects. We also note that neither PG&E nor any party presents any data to justify the deposit amounts, or alternative amounts.

We reach the same conclusion we essentially have reached every year. That is, we have inadequate data to order any other outcome, endorse PG&E's specific numbers, or adopt the specifics of the particular tradeoff (an exact higher deposit amount in exchange for an exact limit of damages).

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[49] *See* Solicitation Protocol, § VII, at 23, footnote 8.

Nonetheless, we accept PG&E's proposal consistent with PG&E reporting that it represents the interest of its counterparties. We also accept the proposal noting that PG&E is ultimately responsible for its Plan, and its success at reaching RPS Program targets. As we have said before, if any utility (including PG&E) fails to reach a Program target and seeks to avoid a non-compliance penalty, that utility must make a showing to justify why it should not pay the non-compliance penalty. That showing should include an explanation that its deposit scheme did not prevent otherwise viable projects from at least coming forward for evaluation. (*See*, for example, D.06-05-039, at 38.)

6.1.3. Other Proposed Changes

PG&E proposes several other changes (summarized in Attachment C). These include: clarifying evaluation protocols, soliciting additional information about supplier diversity, modifying contract terms for more flexibility in construction start date and commercial online date, modifying scheduling coordinator responsibilities, specifying minimum guaranteed annual energy production, streamlining and simplifying the model contract (by combining three former contracts into one), and making conforming changes to STCs. No party comments. We accept these changes, subject to PG&E being responsible for reaching Program targets.

6.2. SCE

We address four elements of SCE's Plan: pre-approvals of short-term contracts, expansion of biomass standard contract to all RPS technologies, credit and collateral provisions, and other changes.

6.2.1. Pre-Approval for Short-Term Contracts

SCE proposes that RPS procurement contracts meeting certain guidelines be treated as per se reasonable and pre-approved by the Commission. The guidelines would include that these contracts be entered into as a result of a competitive process, be limited to 10,000 GWh total cumulative procurement, and generally be limited to terms of five years or less. SCE proposes that resulting transactions under this authority be reported to the Commission via existing procurement plan compliance reports filed quarterly by advice letter.

DRA, Reid, and TURN oppose this proposal. They argue that the proposal would cover a large proportion of RPS procurement and that the Commission would not be able to determine whether certain RPS requirements had been met (e.g., minimum quantity requirement for the use of short-term contracts set forth in D.07-05-028). TURN points out that reasonableness standards for short-term contracts are being separately developed,[50] and that SCE's proposal should not be approved until such standards are in place.

We agree with TURN that the proper place to resolve these disputes is in a separate proposed decision that addresses the streamlining of RPS contracting. SCE's proposal directly implicates proposals for streamlining contract review processes that were being considered in R.06-02-012 and have now been transferred to this proceeding.[51] All these related issues will be considered in a separate proposed decision. SCE's proposal is therefore not accepted as part of its 2009 RPS procurement plan and should be removed from the Amended Plan

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[50] This was undertaken in R.06-02-012, and is now transferred to this proceeding.

[51] *See* Assigned Commissioner’s Ruling Transferring Consideration of Certain Issues from Rulemaking 06-02-012 to Rulemaking 08-08-009 (April 3, 2009).

it will file pursuant to this order. If some or all elements of SCE's proposal are ultimately approved, SCE may amend its 2009 Plan at that time.[52]

6.2.2. RPS Standard Contract Program

SCE reports that it voluntarily initiated a program in 2007 offering standardized contracts to biomass facilities with capacities up to 20 MW per project, priced at the MPR, and subject to a cap of 250 MW for total subscriptions. SCE says it did this to help small biomass projects contribute to California's RPS goals and support the Governor's goal to promote energy production from biomass.[53] SCE extended this opportunity into 2008. For 2009, SCE says it is proposing to expand the program from biomass to all renewable technologies.

The standardized contracts are available for three categories of projects differentiated by size. SCE summarizes what it asserts are the important differences between the three standardized contracts:

[52] If unable to include the provisions within the amended Plan to be filed pursuant to this order, SCE may later file and serve an advice letter to amend its Plan. (*See* GO 96-B.)

[53] SCE cites the Governor's Executive Order S-06-06.

ITEM	UP TO 1.5 MW (WATER/CREST)	GREATER THAN 1.5 MW TO 5 MW	GREATER THAN 5 MW TO 20 MW
Location Restrictions	Must be an SCE retail customer	Must be within CAISO control area	Must be within CAISO control area
Startup Deadline	Within 18 months of signing contract	Within 5 years of contract signing	Seller provides date
Development Security	None	None	$20/kW *
Performance Assurance	None	None	Six months of revenue *

* SCE reports that the amount of development security and performance assurance is being developed.

SCE concludes by saying (as it similarly did in its 2008 Plan):

> Finally, it should be noted that SCE is not necessarily seeking approval of its standard contracts for generators greater than 1.5 MW as part of its 2009 Procurement Plan. [Footnote deleted.] Instead, SCE will file an advice letter, along with a set of executed agreements, seeking approval for any agreements signed pursuant to this standard contract program. (SCE Plan, at 28.)

In assessing this proposal we initially note that the first category (up to 1.5 MW) implements existing requirements. (§ 399.20 and D.07-07-027.) The other two categories comprise SCE's voluntary program. SCE does not provide a copy of the two standardized contracts that are at issue (1.5 MW to 5 MW and 5 MW to 20 MW). SCE refers the Commission and parties to its web page.[54]

We comment on four elements, consistent with and building on our comments in 2008. (*See* D.08-02-008, at 43-44.) First, no party provides material

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[54] We note from the web page that the contracts are largely similar to the model contract SCE includes with its 2009 Plan, but with some differences (e.g., SCE deletes or incorporates into other parts of the agreement: § 1.11 regarding the "Market Price Referent;" § 3.17 regarding the "Availability Guarantee and Obligation to Make Availability Guarantee Lost Production Payment").

comments (e.g., recommending specific changes to one or more standard contracts or applicable price). For this and the reasons stated below, we reach no judgment here on the standard contracts and prices.

Second, SCE does not request acceptance of its standard contracts, or use of the MPR price level. Rather, SCE says it "will file an advice letter, along with a set of executed agreements, seeking approval for any agreements signed pursuant to this standard contract program." (SCE Plan, at 28.) We reach no decision here on the two standard contracts and/or price level. We will make those judgments if and as needed when SCE files an advice letter.

Third, our application of the legislative structure for the RPS Program is to allow each electrical corporation considerable flexibility in the way it meets RPS goals. In exchange, each electric corporation must meet its RPS Program targets, within application of flexible compliance criteria, and penalties apply for failure to meet targets. We accept, reject or modify each Plan before a particular solicitation, but we do so at a reasonably high level.

In this context, what we refer to as SCE's RPS Standard Contract Program (for RPS Projects between 1.5 and 20 MW per project, for a total of 250 MW) appears to be a reasonable application of SCE's business judgment. We accept SCE's RPS Standard Contract Program as part of SCE's 2009 RPS Plan, even though SCE says it is not necessarily seeking Commission acceptance, rejection or modification of these standard contracts as part of its 2009 Procurement Plan, and even though we reach no judgment on the standard contracts. We do this, as we did in 2008, so that such contracts may be judged based on consistency with this Plan.[55]

We also note that thus far SCE has submitted four projects to the Commission that have resulted from its standard contract program. We treated each as a bilateral contract since it did not result from a solicitation. Each contract also contained changes from the standard contract. Changes potentially reduce the benefits otherwise available from a standard contract approach. A completely standardized approach should eliminate the need, in all but the most exceptional of cases, for additional negotiation and modification.

Finally, we see great merit with increased standardization. We recognize SCE's initiative and innovation with this RPS Standard Contract Program. We encourage, but do not require, the other utilities to adopt the same approach. We are separately examining the reasonableness of the use of standardized tariffs with standardized contracts at a similar price and total program cap.[56] We expect to issue an order soon which will address this in the context of what many refer to as the "feed-in tariff."

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[55] Contracts submitted for our consideration that are not part of an accepted Plan may be reviewed by application of other criteria, such as those used for a bilateral contract. Accepting SCE's RPS Standard Contract Program as part of SCE's 2009 Procurement Plan, however, permits consideration of these contracts for consistency with the approved Plan (§ 399.14(d)) while not foreclosing consideration using other criteria, if appropriate.

[56] For example, one proposal under consideration is a standard tariff/contract at the MPR price level for a total of 1,000 MW statewide (which is about 500 MW when allocated to SCE). (*See* March 27, 2009 Ruling on Additional Commission Consideration of a Feed-In Tariff.)

6.2.3. Credit and Collateral Provisions

SCE says it has (a) eliminated the Reduced Development Security Option, (b) increased its Development Security requirements, (c) eliminated the subordinated security interest provisions in its pro forma agreement and (d) revised its requirement for sellers to post performance assurance. We briefly describe each in Appendix C.

No party objects to these proposals. We have inadequate information upon which to reach a judgment and, as we have said before regarding collateral (and said above regarding PG&E), we have inadequate evidence to affirm any particular numbers. We accept SCE's proposals consistent with SCE being responsible for its portion of program success, and subject to SCE meeting Program Targets.

6.2.4. Other

SCE makes several other changes. These include, but are not limited to: (a) revised insurance provisions to reflect current market conditions; (b) added North American Electricity Council requirements to reflect the existing obligations of applicable generating facilities; (c) added a cap on the expenditures required by sellers to comply with changes in RPS Program requirements; (d) deleted STC 3 (Supplemental Energy Payments) in accordance with D.08-04-009 and replaced STC 3 with an above market funds (AMFs) provision; (e) modified delivery point and other related provisions to take into account the CAISO's planned Market Redesign and Technology Update; (f) modified the definition of Green Attributes in accordance with D.08-08-028; and (g) other improvements to bid solicitation materials to provide greater clarity through improved formatting, structural and grammatical changes.

No party comments on these changes. We accept these changes, consistent with SCE being responsible for it portion of program success, and subject to SCE meeting Program Targets, with the exception of the AMFs term. As proposed by SCE, the new AMFs term may conflict with statute. SCE should consult with staff to develop an improved term.[57]

6.3. SDG&E

We address three elements of SDG&E's Plan: Imperial Valley-specific solicitation, financial impacts and other.

6.3.1. Imperial Valley-Specific Solicitation

SDG&E says:

> In order to ensure the availability of Imperial Valley [IV] resources, SDG&E intends to seek Commission approval to include an IV-specific solicitation within its 2009 general RPS solicitation. The IV-specific solicitation would include special instructions and other relevant information in a separate section of the main solicitation document. (February 27, 2009, Sunrise Comments, at 10.)

SDG&E describes its proposal as "a 'sub-solicitation' within SDG&E's general RPS solicitation." (Id., at 11.) SDG&E asserts the sub-solicitation:

> … would help to prevent confusion that may be associated with different solicitations being issued at different times and will avoid the burden—to bidders, the Commission and SDG&E alike—associated with conducting multiple stand-alone solicitations. (Id., at 11.)

[57] § 399.15(d) sets one particular limit, but also provides that "nothing in this section prevents an electrical corporation from voluntarily proposing to procure eligible renewable energy resources at above-market prices that are not counted toward the cost limitation." (§ 399.15(d)(4).) This appears to conflict with § 2.05 of SCE's *pro forma* contract. (Attachment 2-3 of SCE's 2009 RPS Procurement Plan.)

We accept SDG&E's proposal. Upon Commission approval of Sunrise, SDG&E committed to, among other things, replacing

> … any currently approved renewable energy contract deliverable via Sunrise that fails with a viable contract with a renewable generator located in Imperial Valley. (D.08-12-058, at 260.)

Accepting SDG&E's proposal here is consistent with allowing SDG&E to fulfill this commitment. SDG&E may also (along with other utilities) undertake all other reasonable actions to highlight the unique and important opportunities created by Sunrise (e.g., a special bidders conference), and to facilitate development of those resources (e.g., locate a regional office in Imperial Valley).

6.3.2. Financial Impacts

SDG&E's Plan specifically requests that the Commission here:

(a) expressly acknowledge the importance of acting to mitigate any negative impact on SDG&E's balance sheet and/or credit profile caused by application of debt equivalence and/or FIN 46(R) requirements, and

(b) affirm that to the extent that a PPA negatively affects SDG&E's credit rating and SDG&E files a capital structure adjustment application pursuant to D.08-05-035, the Commission will seek to mitigate such impacts through expeditious consideration of such application. (SDG&E Plan, at 30.)

SDG&E offers nothing to change our previous statements on these points. We have addressed both points in recent orders (e.g., D.07-02-011, D.07-12-049, D.07-12-052, D.08-05-035). In summary, we will take action to address negative impacts on any utility's balance sheet or credit profile when warranted and necessary, and will do so in a manner consistent with the urgency of the matter.

6.3.3. Other

SDG&E identifies several other changes, which are summarized in Appendix C. In short, these include: one team for evaluations, potential use of outside consultants to perform LCBF quantitative analysis, revised description of its TOU cost adjustment, use of average bid prices for its LCBF duration equalization, inclusion of UOG of between 20 MW and 35 MW, pricing form simplification, and improved offer narratives. No party objects. We accept these changes consistent with SDG&E being responsible for it portion of program success, and subject to SDG&E meeting Program Targets.

6.4. PacificCorp

We accept PacifiCorp's 2009 IRP Supplement, but note the need for certain improvements in 2010. We begin with a brief description of PacifiCorp's situation and showing, and conclude with examples of necessary improvements.

PacifiCorp operates in six states (California, Oregon, Washington, Utah, Idaho, and Wyoming). It operates its own balancing authority, and is subject to WECC and North American Electric Reliability Council requirements, but is not part of the CAISO. PacifiCorp explains that it does resource planning on a system-wide basis, and does not procure any resources on a California-specific basis. PacifiCorp affirms its commitment to satisfying California's requirement of 20% renewables by 2010, with the use of flexible compliance and earmarking as needed.

PacifiCorp shows it is actively procuring renewables in order to reach its RPS targets. For example, in 2008 PacifiCorp initiated two RFPs seeking 900 MW of renewable resources by 2011. PacifiCorp reports that its Plan also includes 2,000 MW of renewables by 2013. (2007 Integrated Resource Plan (IRP) Update, Attachment A, at 1.) PacifiCorp also reports a commitment to the Energy

Gateway Project to, among other things, provide transmission access for renewable resources.[58]

We appreciate PacifiCorp's commitment to meeting its California RPS Program obligation of 20% by 2010. Nonetheless, PacifiCorp's 2009 IRP Supplement does not make entirely clear how it will achieve this goal. PacifiCorp must improve its showing for the 2010. We describe several examples.

PacifiCorp's 2009 IRP Supplement shows it intends to procure 93,368 MWh of RPS-eligible procurement in 2010, and 89,799 MWh in 2013 (the end of the three-year flexible compliance period). This is 10.7% and 10.4%, respectively, of its estimated retail sales of 868,999 MWh in 2010 and 866,154 MWh in 2013.[59] (2009 IRP Supplement, Item 2, Program Metrics, Attachment A, at 2.) PacifiCorp must do a better job next year of showing how it will reach 20% by 2010 (or 2013 using the maximum flexible compliance), or explaining its basis for not having a plan that shows reaching these RPS Program targets.

Similarly, PacifiCorp's response to several issues identified in the Amended Scoping Memo is: "not applicable." In support of its response, PacifiCorp explains that it operates on a system-wide basis, and not a California-only basis. Even if this is true, PacifiCorp does not adequately explain why it

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[58] The Energy Gateway Project is a regional transmission project estimated to cost more than $6 billion for more than 2,000 miles of extra-high voltage transmission lines located in Oregon, Washington, Utah, Idaho and Wyoming.

[59] A motion is pending regarding reporting treatment of RPS purchases and obligations. The motion addresses establishment of annual procurement targets and flexible compliance, but does not change the 20% by 2010 obligation (or 20% by 2013 using the full three years of flexible compliance).

cannot provide responses reflective of its system. These might be, for example, a copy of its system-wide RFP (in place of a California-focused bid solicitation), a showing of how its system-wide procurement plan reasonably includes a procurement margin of safety (to account for potential contract failure or other contingencies), or whether or not the Commission should determine if and when a utility may execute an exclusivity agreement.[60]

Each IOU was required to show its workplan for reaching 20% by 2010. In response, PacifiCorp discusses a "Revised Protocol" allocation methodology. The methodology is used to allocate costs and revenues. According to PacifiCorp, it is also used to allocate to each state jurisdiction its share of renewables output generated by the utility-owned system resources.

PacifiCorp acknowledges the "Revised Protocol presents a challenge for PacifiCorp in meeting California's 2010 RPS targets." (2009 IRP Supplement, Item 7, Response, Attachment A, at 5.) PacifiCorp states that it "may propose to implement a renewable pilot program that would allow for the intra-Company transfer of renewable resources for California compliance purposes." (*Id.*) This does not adequately explain PacifiCorp's current workplan for reaching California's RPS Program targets. Whether or not PacifiCorp decides to later propose implementation of a pilot program, PacifiCorp must satisfy California's RPS Program target of 20% by 2010 (or 2013 using the full three years of flexible compliance), and its annual RPS Procurement Plan must explain its plan to do so.

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[60] *See*, for example 2009 IRP Supplement, Items 1.3, 2.6, 6.1 and 6.2.

Thus, we accept PacifiCorp's 2009 IRP Supplement consistent with PacifiCorp being responsible for meeting applicable RPS Program Targets. We expect PacifiCorp to do a better job in its next annual RPS showing.

6.5. Sierra Pacific Power Company

Sierra reports that it is currently in compliance with its California RPS procurement obligations, expects to remain in compliance, and is currently sufficiently resourced to meet its 20% by 2010 obligation. Sierra states that it has no RPS solicitation pending or scheduled for California (since it is fully resourced with respect to California), but will issue an RFP to comply with its Nevada-based requirements.

Sierra's 2009 IRP Supplement reasonably addresses its unique, fully-RPS resourced position. We are confident that Sierra will provide more detail in subsequent reports, as necessary, should this fully-RPS resourced situation change.

7. Schedule for 2009 Solicitations and Organization of 2010 Plans

7.1. 2009 Solicitation

The IOUs propose similar solicitation schedules for 2009. That is, while particular dates vary, IOUs propose approximately the same window of time between important events.

We generally adopt the schedule reflected in their proposals. (*See* Appendix B.) We adjust the dates to be consistent with the date of this order. We limit the adopted schedule to major milestones. This permits IOUs and staff reasonable flexibility, just as we did in 2008.

We set a date, beginning with this solicitation, before which an IOU may not request an exclusivity agreement before continuing with negotiations. PG&E and SDG&E recommend such a date in principal but neither includes a specific date in its proposed schedule. For this purpose we adopt the date that each IOU notifies each winning bidder that it has been placed on the IOU's shortlist. It is then up to the bidder to determine whether or not to accept the shortlist position and execute an exclusive agreement to engage in further negotiations.

Finally, we adjust the date for submitting contracts that may be earmarked for meeting 2009 targets. The propose decision recommended December 31, 2009, but we move the date to April 30, 2010. We do this to provide a comparable amount of time as used in the 2008 solicitation. Moreover, as requested by SCE, we clarify that contracts (including those from the 2008 solicitation) are eligible for earmarking based on the date they are submitted to the Commission for approval, unless the resolution or decision approving the contract adopts a different date.

7.2. 2010 Plans and IRPs

We adopt the same basic approach here for the 2010 cycle as we used in developing and reviewing the 2006, 2007, 2008 and 2009 Plans. (D.05-07-039, at 29; D.06-05-039, at 58; D.07-02-011, at 61, D.08-02-008, at 46.) That is, we expect the filing and service of 2010 draft RPS plans and draft RFOs later this year for the three IOUs (e.g., by November 1 so they potentially may be accepted in the second quarter of 2010). This is also true for the IRP and Supplement for the MJUs. 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, D.06-05-039, D.07-02-011, D.08-02-008.) 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; D.06-05-039, Ordering Paragraph 7; D.07-02-011, Ordering Paragraph 5.)

We remain on a schedule which largely anticipates annual RPS solicitations for the largest three IOUs. We again encourage IOUs to consider proposing something other than an annual cycle. (*See* D.06-05-039, at 55-60.) We do this noting several things. SDG&E pointed out in 2006, for example, that the option for bilateral contracting essentially provides a continuous opportunity to obtain RPS resources. (D.06-05-039, at 56, footnote 23.) SCE is concerned that when IOUs are constrained to a procurement cycle that others are not there is increasing risk of harmful competition for RPS resources from ESPs, municipal utilities and out-of-state utilities. Commission-regulated MJUs (along with CCAs and ESPs) engage in RPS solicitations on a schedule that we do not dictate. In addition, external events sometimes result in our taking longer to approve a particular solicitation.[61]

There may be advantages and disadvantages to different types of RPS solicitations. The extremes might be (a) a very structured periodic (e.g., annual) solicitation or (b) a continuous solicitation. (*See* D.06-05-039, at 55-56.) As we said in 2006, we think there are other reasonable options to the approach we are now using. We encourage IOUs and MJUs to consider the options and, where

[61] Approval of the nearly $2 billion Sunrise Transmission Project in late 2008, for example, prompted us to require further information from utilities for the 2009 solicitation.

feasible, propose alternatives that accomplish RPS Program objectives while mitigating some of the burdens placed on all stakeholders from an annual solicitation.

We also note that the next solicitation may be the last one for each utility to secure contracts to meet the target of 20% by 2010 (subject to flexible compliance provisions). In comments on the proposed decision, IOUs uniformly argue for a later date for the 2010 solicitation in order to allow incorporation of "lessons learned" from the 2009 solicitation. A reason for an earlier date, however, may be to secure additional contracts to meet targets, including a reasonable margin of safety. Based on comments from IOUs on the proposed decision, IOUs seemingly have a reasonable level of comfort in meeting targets. Should this change, however, we are open to IOUs filing a pleading asking for another competitive solicitation sooner rather than later. We do not specify the parameters here, but we note that it may be reasonable to hold another solicitation very early 2010 (perhaps just six or eight months after the 2009 solicitation) in order to provide a full opportunity for IOUs to meet RPS program targets. We make no such provision here since, at the moment, IOUs express no concern. We leave the matter open, however, for consideration by IOUs and stakeholders.

8. Comments on Proposed Decision

On May 1, 2009, the proposed decision of ALJ Mattson in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules). On or about May 21, 2009, comments were filed by 14 parties.[62] On or about May 26, 2009 reply comments were filed by four parties.[63] As required by our rules, comments must focus on factual, legal or technical errors and, in citing such errors, must make specific references to the record. Comments which merely reargue positions taken in the proceeding are given no weight. (Rule 14.3.)

We carefully consider comments which focus on factual, legal or technical errors, with citation to the record, and make appropriate changes to the proposed decision. In particular, we clarify that IOUs must use the final staff project viability methodology and calculator; clarify that deletion of TREC material from Plans is with regard to the use of TRECs to meet RPS Program targets; modify the discussion regarding transmission network upgrades; adjust the schedule for earmarking from the 2009 solicitation, the estimated filing of the 2010 Plans, and note that IOUs may file a pleading for an "early" solicitation in 2010 if needed to meet the 2010 RPS target of 20%; and make other modifications for clarification as necessary.

9. 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. No motion for evidentiary hearing was filed.

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[62] Comments were filed by PG&E, SCE, SDG&E, DRA, GPI, LSA, IEP, UCS, CEERT, CalWEA, Reid, SES, and jointly by Alliance For Retail Energy Markets (AReM) and Western Power Trading Forum (WPTF).

[63] Reply Comments were filed by PG&E, SCE, DRA and CalWEA.

2. A special Imperial Valley bidders conference will highlight the unique opportunities created by Sunrise, and is expected to increase both the number and viability of proposed projects.

3. Allowing each IOU to schedule the special Imperial Valley bidding conference at a time and place that it believes is most efficient will reasonably address certain concerns (e.g., developers not having business development staff in Imperial Valley).

4. Specific subjects must be included in the special bidders conference to highlight the special importance and unique expectations relative to Imperial Valley renewable resources and Sunrise.

5. Specific monitoring of Imperial Valley proposals and projects is consistent with Sunrise being a relatively important and costly project in California, and deserving reasonable attention to ensure that it is used efficiently, equitably, and wisely.

6. Monitoring of Imperial Valley proposals and projects will not cause unreasonable preference to be given in the LCBF selection process to Imperial Valley projects, and will not create undue pressure to select or approve bids otherwise contrary to LCBF evaluation.

7. It is premature to adopt remedial measures now for the 2010 RPS solicitation relative to Imperial Valley projects.

8. Current project viability assessment tools can be improved by adopting a requirement for a more transparent and uniform approach, with this improved approach also promoting an increase in the public's confidence that projects with demonstrated indicia of viability are given appropriate weight.

9. Certain solicitation-wide project viability data included in the public version of advice letters seeking Commission approval of an RPS contract will

promote an increase in the transparency of an IOU's assessment of project viability.

10. Development security serves several purposes, and balances many competing interests, including its relationship to project viability, replacement cost and financial incentives to honor an agreement.

11. The project viability calculator needs further development and testing before adopting it as the tool to determine whether an RPS contract or amendment is eligible to be considered by the Commission.

12. Project viability score is not necessarily an exact predictor of an outcome, and linking project viability score with flexible compliance will increase the complexity of flexible compliance administration.

13. Utilities have substantial incentive to select viable projects given that flexible compliance applies only within a three year window; utilities must include a margin of safety in procurement plans as a buffer against contingencies; meeting RPS targets is measured by actual energy deliveries; utilities are expected to give reasonable consideration to building and owning RPS plant, if necessary, to meet RPS goals; and failure to meet targets exposes the utility to a penalty up to $25 million.

14. In 2004, the Commission determined that exclusivity for ongoing negotiations is a reasonable requirement, but did not establish a uniform date to trigger exclusivity.

15. A uniform exclusivity date averts premature shortlisting that might otherwise lead to undesirable bidding wars, which could allow bidders to extract concessions from an IOU in order to continue negotiations at an unnecessary cost increase to ratepayers.

16. It is premature to authorize use of TRECs for RPS compliance (even subject to conditions) until the Commission actually authorizes use of TRECs.

17. STC 5 (Contract Term) permits a bidder to propose a contract for any specifically stated number of years.

18. SCE's RFP does not permit proposals longer than 20 years, while SDG&E's RFO and PG&E's Protocol are not entirely clear that proposals over 20 years may be made.

19. Some project developers are interested in making proposals for contracts that are longer than 20 years, and the Commission has recently adopted MPRs in excess of 20 years.

20. No party convincingly argues against Commission acceptance of IOU-proposed changes to the IOU's LCBF methodology.

21. There is no evidence to order different TOU factors at this time.

22. The information in each IOU's Plan regarding its current consideration of whether or not to build its own renewable resources to reach 20% by 2010 is (as it was in previous plans) relatively short and generally inconclusive.

23. IOU Plans continue to be relative complex documents (including many attachments, different model contracts and multiple related forms), and continuing with incremental improvements toward standardization and more uniformity in form and format will advance the goals of increased simplicity, transparency, efficiency and competition.

24. In response to bidder feedback, PG&E proposes changes in its development security amounts and policy.

25. SCE does not necessarily seek approval of its RPS Standard Contract Program (for projects up to 20 MW), or the related standard contracts as part of its 2009 Plan.

26. PacifiCorp's comprehensive Supplement does not clearly show how it will achieve 20% by 2010.

Conclusions of Law

1. With some exceptions, electric utilities are required to prepare a renewable energy procurement plan, and the Commission is required to review and accept, modify, or reject each plan.

2. Electric utilities should continue to have reasonable flexibility in the way each satisfies RPS program requirements, subject to Commission guidance, limited specific requirements, and certain specific dates (where applicable) for the 2009 solicitation cycle.

3. Conditional approval of each 2009 RPS Plan (including Protocol, RFO, RFP, model contracts, other forms), and each 2009 comprehensive Supplement to the IRP, does not constitute endorsement or adoption of each element of each Plan or Supplement; rather, each utility remains responsible for overall program success, subject to rules for flexible compliance and tests of reasonableness (e.g., how each entity administers the program, including the extent to which each entity takes Commission guidance; demonstrates creativity and vigor in program execution; and successfully reaches program goals, targets and requirements).

4. The proposed 2009 RPS Procurement Plans of PG&E, SCE and SDG&E should each be conditionally accepted, subject to the guidance, necessary modifications, changes and clarifications stated in this order, including, but not necessarily limited to, each item summarized in Appendix A; and the 2009 comprehensive Supplements to IRPs of PacifiCorp and Sierra should each be accepted subject to the guidance stated in this order including, but not limited to, the relevant items summarized in Appendix A.

5. PG&E, SCE and SDG&E should each, within 14 days of the date this order is mailed, file an amended Plan with the Commission's Docket Office, serve it on the service list, and also file a copy with the Energy Division Director. Unless suspended by the Executive Director or Energy Division Director within 21 days of the date this order is mailed, each utility should use its amended Plan for its 2009 RPS solicitation.

6. PG&E, SCE and SDG&E should each hold a special Imperial Valley bidders conference (at a time and place it determines most efficient for the IOU and stakeholders), the conference should include presentation of certain information by the host (e.g., Commission approval and intentions; project information; estimates of renewable deliveries; SDG&E commitments), and 2010 RPS Procurement Plans should report on the 2009 special bidders conference.

7. Imperial Valley projects and proposals should be monitored, and the IOUs (PG&E, SCE, SDG&E) should provide specific information to Energy Division (when requested by Energy Division).

8. Remedial measure for the 2010 solicitation relative to Imperial Valley projects should not be adopted now, but parties should continue to consider remedial measures and make recommendations, as appropriate.

9. Each IOU should include an improved project viability methodology and calculator with its amended Plan, as specified by Energy Division.

10. The project viability calculator should be used as a screening tool, not to determine the exact merit of a project or contract.

11. Solicitation-wide project viability calculator information and results should be included with each advice letter seeking approval of an RPS contract in order to increase the transparency of project assessments, but project-specific project viability calculator information and results should not be made public to

the extent it falls within guidelines adopted in our confidentiality orders (e.g., D.06-06-066).

12. Development security amounts and protocols should not be strictly linked to project viability calculator at this time.

13. The Commission should not at this time adopt a categorization of projects by project viability calculator score that limits the Commission's discretion to consider a range of projects, contracts and contract amendments.

14. Flexible compliance rules should not be linked to scores from the project viability calculator at this time.

15. Flexible compliance provisions do not excuse a utility from fulfilling its RPS Program targets with actual deliveries of energy by the end of the flexible compliance period.

16. Seller non-performance should not at this time be eliminated as a factor in the rules for flexible compliance.

17. A uniform date should be adopted before which an IOU may not require that a bidder execute an agreement requiring exclusive negotiations with the IOU.

18. Plans should not include use of TRECs to meet RPS Program targets (even subject to conditions) until the Commission has actually authorized the use of TRECs and clarified the conditions upon which TRECs may or may not be used.

19. STC 5 is modifiable and does not need further modification to permit a bidder to propose a contract with a term longer than 20 years, but each IOU Plan should exclude language which would otherwise foreclose or discourage proposals in excess of 20 years.

20. Each IOU's amended Plan should include discussion of upfront funding of transmission upgrades to the extent this funding is intended to be a component of its 2009 Plan to reach RPS goals.

21. IOU proposals to modify LCBF methods should be accepted.

22. SDG&E should include both energy-only and all-in TOU factors in its next TOU showing.

23. No provision should be adopted here to retroactively apply TOU factors later decided in the LTPP proceeding back to the 2009 Plans.

24. IOUs should undertake all reasonable actions to comply with RPS targets, including UOG when necessary and appropriate, and amended Plans should include additional description of UOG as needed to ensure IOUs meet RPS Program targets.

25. IOUs should continue to make incremental improvement toward adopting a common and streamlined form and format for RPS Plans, including the overall summary document and multiple attachments (e.g., Protocol, RFP, RFO, model contracts, multiple related forms).

26. IOU proposed changes (e.g., development security, streamlining and simplifying model contracts, reduced development security option, subordinated security interest, revised insurance provisions, one team for evaluations) should be accepted to the extent described herein, consistent with the IOU ultimately being responsible for its portion of RPS Program success, with limited exceptions noted herein.

27. SCE's RPS Standard Contract Program (1.5 MW to 20 MW per project, for a total of 250 MW) should be accepted as part of SCE's 2009 RPS Procurement Plan.

28. SDG&E's proposal for an Imperial Valley-specific solicitation should be accepted.

29. PG&E's proposal for a "Pilot Program for Pre-Approvals," and SCE proposal for "Pre-Approvals for Short-Term Contracts" should not be adopted in this order, but should be considered in another order.

30. PacifiCorp should make clear in its next IRP or Supplement how it intends to achieve 20% by 2010.

31. The 2009 RPS solicitation schedule in Appendix B should be adopted.

32. The same approach for Commission review and acceptance, rejection or modification of the 2010 RPS Procurement Plans should be used as employed for prior Plans, with the assigned Commissioner setting the specific schedule and addressing TRCRs.

33. Evidentiary hearings are not necessary.

34. This proceeding should remain open.

35. This order should be effective today so that the 2009 RPS solicitation may proceed without delay.

O R D E R

IT IS ORDERED that:

1. Each utility-proposed renewable energy procurement plan, as part of the California Renewables Portfolio Standards Program, is conditionally accepted for the next Renewables Portfolio Standards Program solicitation cycle. Each Plan includes, but is not limited to, Protocols, Request for Proposals, Request for Offers, model contracts and/or Power Purchase Agreements. The Plans are in the following documents:

a. The Pacific Gas and Electric Company "2009 Renewable Energy Procurement Plan" filed September 15, 2008, including 2009 Solicitation Protocol, and as further addressed in February 27, 2009 Sunrise Comments, and March 6, 2009 Sunrise Reply Comments.

b. The Southern California Edison Company "2009 RPS Procurement Plan" filed September 15, 2008, including the 2009 Request for Proposals, and as further addressed in February 27, 2009 Sunrise Comments, and March 6, 2009 Sunrise Reply Comments.

c. The San Diego Gas & Electric Company "2009 Renewables Procurement Plan" filed September 15, 2008, including the 2009 Request for Offers, and as further addressed in February 27, 2009 Sunrise Comments, and March 6, 2009 Sunrise Reply Comments.

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

a. Within 14 days of the date this order is mailed, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file and serve an amended Renewables Portfolio Standard Procurement Plan that is consistent with all the orders in this decision, plus all guidance in this decision with which the utility agrees, and simultaneously file a copy with the Director of the Energy Division. The orders and guidance are summarized in, but not limited to, Appendix A.

b. Unless suspended by the Executive Director or Energy Division Director within 21 days of the date this order is mailed, each utility shall use its amended Renewables Portfolio Standard Procurement Plan for its 2009 solicitation.

3. The 2009 Renewables Portfolio Standard procurement cycle shall be as stated in Appendix B. The schedule may be modified by the Executive Director or Energy Division Director as reasonable and necessary for efficient administration of this solicitation. Parties may seek schedule modification by letter to the Executive Director (pursuant to Commission Rules of Practice and Procedure).

4. The PacifiCorp "Supplement to its 2007 Integrated Resource Plan (2009 Supplement)" filed September 15, 2008, and the Sierra Pacific Power Company "Renewable Portfolio Standard 2009 Supplemental Filing" filed September 15, 2008, are each accepted.

5. Consistent with all prior and current Commission orders and directions, each utility ultimately remains responsible for reasonable Renewables Portfolio Standard 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 Renewables Portfolio Standard Procurement Plan. The Commission shall also judge contract results, program results, and non-compliance pleadings by (but not limited to) considering the degree to which each utility implements Commission orders; reasonably elects to take or reject the guidance provided herein; reasonably demonstrates creativity, innovation and vigor in program execution; reaches program targets and requirements; and shows it took all reasonable actions to achieve compliance, including but not limited to the factors identified in this and prior orders.

6. The assigned Commissioner or Administrative Law Judge in this, or a successor, proceeding shall set a schedule for the filing and service of proposed Renewables Portfolio Standard Procurement Plans for the 2010 solicitation, including the filing of Integrated Resource Plans and Supplements, as necessary. The assigned Commissioner or Administrative Law Judge shall set a schedule for matters related to Transmission Ranking Cost Reports to be used in the ranking of bids in a Renewables Portfolio Standard solicitation. The assigned Commissioner shall assess the adequacy of each Transmission Ranking Cost Report based on filed comments and reply comments, and shall determine

whether each Transmission Ranking Cost Report shall be accepted, modified, or other steps taken before a Transmission Ranking Cost Report is used in ranking bids in a Renewables Portfolio Standard solicitation.

7. Rulemaking 08-08-009 remains open.

This order is effective today.

Dated June 4, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners