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

DECISION ADOPTING THE RENEWABLE AUCTION MECHANISM

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DECISION ADOPTING THE RENEWABLE AUCTION MECHANISM

1. Summary

This decision authorizes a new procurement process called the Renewable Auction Mechanism, or RAM, for the procurement of smaller renewable energy projects that are eligible for the California Renewables Portfolio Standard (RPS) Program. The RAM is a simplified and market-based procurement mechanism for large investor-owned utilities (IOU). The Commission adopts RAM as a primary contracting tool for this market segment because doing so will promote competition and elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term. We expect RAM to complement the RPS Program by reducing transaction costs and providing a procurement opportunity for smaller RPS-eligible projects, which have not been able to effectively participate in the annual RPS solicitations to date.

RAM evolved from the Commission's inquiry into expanding the existing feed-in tariff program for generators 1.5 MW and below, pursuant to Public Utilities Code Section 399.20 and Decision (D.)07-07-027. However, RAM is distinct from a feed-in tariff as that term has traditionally been used. While it is a streamlined contracting mechanism and utilizes a standard contract, RAM relies on market-based pricing, utilizes project viability screens, and selects projects based on least cost rather than on a first-come first-served basis at an administratively determined price.

The rules adopted for RAM in this decision are intended to reduce transaction costs, promote regulatory certainty, and provide value to the market, utility, regulator, and ratepayer. For this initial implementation of the program, we direct Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E),

and Southern California Edison (SCE) to use RAM to procure at least 1,000 MW, allocated proportionally by retail sales to each IOU, over two years. All projects solicited through RAM must be 20 MW or less and located within one of the IOU's service territories. We require each IOU to determine upfront the types of products (e.g. baseload, peaking as-available, non-peaking as-available) they intend to procure under RAM to ensure their procurement is consistent with their portfolio needs. This will also provide developers and investors greater clarity and certainty regarding the market opportunity this program provides.

In each RAM solicitation, bids will be screened for viability and selected based on price, using a streamlined utility bid evaluation process that serves to expedite the procurement and review process and increase market transparency. While IOUs must follow these protocols for bid selection, they have the discretion to reject bids if they determine that there was market manipulation and/or if the bid prices are not cost-competitive. Executed contracts resulting from RAM solicitations that fall under the IOU's allocated capacity cap, as described below, can be submitted through a simplified (Tier 2) advice letter process. This pre-approval process benefits all stakeholders by reducing the ratepayer's exposure to risk and allowing regulators to monitor the market before authorizing more RAM procurement.

Our intent in establishing RAM is to create a standardized procurement process for projects up to 20 MW in size in order to promote robust competition and reduce the administrative burden associated with these projects. Going forward, RAM should be the primary procurement vehicle for projects in this size range, though projects may still participate in other Commission-authorized programs such as the annual RPS solicitations and Commission-approved utility solar photovoltaic programs. It is contrary to the intent of this program to allow projects in this size range to use other procurement options, in particular voluntary programs that target the same market segment or bilateral negotiations. Thus, going forward, SCE shall conform its Renewables Standard Contract (RSC) program to the guidance and framework provided herein. However, SCE may count contracts already executed pursuant to its 2010 RSC towards its capacity cap to the extent they are approved by the Commission. Furthermore, SCE may submit additional contracts resulting from its 2010 RSC solicitation via a Tier 3 advice letter for Commission approval, however, these additional contracts will not further reduce SCE's procurement obligation under the RAM program.

Within 60 days, each IOU will file an implementation advice letter with its allocation of megawatts per product category, procurement protocols, and a standard contract that is consistent with the requirements in this decision.

Further, we authorize the Director of Energy Division to explore methodologies for evaluating the utilities' need for system-side renewable distributed generation up to 20 MW in coordination with Commission procurement planning and how we might integrate this need determination into the RAM program. In addition, we expect Energy Division and parties to continually monitor the RAM program, and recommend modifications based on evidence, if and as necessary. We authorize the Director of Energy Division to act on its own motion to revise any aspect of the RAM program through resolutions proposed for Commission approval. We summarize the adopted program in Appendix A. This proceeding remains open.

2. Background

2.1. Legislation and Initial Implementation

Beginning in 2007, California law required, as part of the RPS program, that every electrical corporation have a feed-in tariff (FIT) to purchase electricity at the market price referent (MPR) from renewable facilities up to 1.5 MW owned by public water and wastewater agency customers.[1] The tariffs were available until the combined statewide cumulative capacity of those facilities equaled 250 MW.

We implemented this law in July 2007 in D.07-07-027 and expanded the program at that time from water/wastewater agency retail customers to other customers in the Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) service territories on the same basic terms and conditions. This added an additional 228 MW to the program, bringing the required FIT program total to 478 MW. We resolved applications for rehearing of D.07-07-027 in February 2008 in D.08-02-010. The resulting IOU tariffs – which we refer to as the "Existing FITs" and the entire program as the "Existing FIT"- became effective over the course of the next few months.

An Amended Scoping Memo and Ruling was filed on June 5, 2008 (June 2008 Amended Scoping Memo and Ruling). The assigned Commissioner identified five issues for consideration, and set a schedule for comments and motions. The five issues were:

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[1] Pub. Util. Code § 399.20, added by Assembly Bill (AB) 1969 (Stats. 2006, ch. 731) effective January 1, 2007. Unless noted otherwise, all subsequent statutory references are to the Public Utilities Code.

1. **Program Extension for San Diego Gas & Electric Company (SDG&E)**: Whether or not to extend the tariffs for water/wastewater customers to other customers in the service territory of SDG&E (as we had already done for other customers in the service territories of PG&E and SCE);
2. **Eligible Project Size**: Whether or not to increase the eligible project size from 1.5 MW to 20 MW;
3. **Excess Sales**: How to count electricity purchased pursuant to an excess sales arrangement toward program limits;
4. **Third Party Ownership:** What changes, if any, are necessary to permit third party ownership; and
5. **Other**: Anything else a party recommends be considered by the Commission to complete implementation.

On July 3, 2008, comments were filed by 16 parties.[2] On July 14, 2008, reply comments were filed by 13 parties.[3]

The first of five issues was whether or not the existing program for public water and wastewater agency customers should be extended to other customers in the SDG&E service area. No party filed comments in opposition to the extension and, on September 18, 2008, the extension was adopted. (See D.08-09-033.) This added an additional 20 MW to the Existing FIT program, bringing the statewide combined total from 478 MW to 498 MW.

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[2] Comments were filed by PG&E; SCE; SDG&E; PacifiCorp; Sierra Pacific Power Company (Sierra); Division of Ratepayer Advocates (DRA); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Alliance for Retail Energy Markets (AReM); California Farm Bureau Federation (Farm Bureau); Sustainable Conservation; The Vote Solar Initiative (Vote Solar); Recurrent Energy, Inc. (Recurrent); Solar Alliance; The California Solar Energy Industries Association (CALSEIA); and GreenVolts. Comments of Sempra Energy Solutions LLC were served but not filed. These comments are referred to herein as Initial FIT comments.

[3] Reply Comments were filed by PG&E, SCE, Sierra, GPI, AReM, Vote Solar, Recurrent, Solar Alliance, CALSEIA, GreenVolts, The Utility Reform Network (TURN), Farm Bureau and Sustainable Conservation. These comments are referred to herein as Initial FIT reply comments.

The second issue – whether or not the eligible project size should be increased from 1.5 MW to 20 MW – involved considerable additional work. Among the comments, for example, some parties stated that additional terms and conditions would need to be added to the Existing FITs to accommodate increased project size.

On October 10, 2008, the Commission's Energy Division (ED) sought further data from parties on this issue. The information and comments were received on October 24, 2008. A second ED data request was issued on January 28, 2009, focusing specifically on contract terms and conditions. Parties submitted data responses and comments on February 4, 2009. On February 10, 2009, ED held a workshop regarding standard terms and conditions for a FIT.

ED staff used this material to develop a proposal to expand the size of the Existing FIT. By ruling dated March 27, 2009, the ED staff proposal titled "Feed-in Tariff for Renewable Generators Greater than 1.5 MW" was filed and served to parties for comment. Among other things, ED stated that price level and rate structure are essential to FIT program success, and would be addressed in a future phase of the proceeding. Dates were set for comments and motions.

On April 10, 2009, comments were filed by 21 parties.[4] On April 17, 2009, reply comments were filed by 10 parties.[5] Some parties stated that price cannot

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[4] Comments were filed by PG&E; SCE; SDG&E; DRA; TURN; Center for Energy Efficiency and Renewable Technologies (CEERT); GPI; Solutions for Utilities, Inc. (SFUI); Sustainable Conservation; Sierra Club (Sierra Club); Community Environmental Council (Environmental Council); IEP; FuelCell Energy, Inc. (FuelCell Energy); Redwood Renewables (RR); Los Angeles Community College District (LA Community College District); City of Santa Monica (Santa Monica); CALSEIA; Solar Alliance and Vote Solar (jointly); First Solar, Inc. (First Solar); and AReM. These comments are referred to herein as the Terms and Conditions Comments.

be separated from FIT terms and conditions. Some stated that price is a critical element and its consideration should not be deferred. Others questioned the Commission's jurisdiction to set a FIT price.

By ruling dated May 28, 2009, parties were directed to file briefs on the jurisdiction issue, along with recommended pricing mechanisms consistent with their views on jurisdiction. Opening briefs were filed by 14 parties.[6] Reply briefs were filed by 10 parties.[7]

ED staff then prepared a pricing proposal, which forms the basis of the Renewable Auction Mechanism, or RAM, that we adopt today. RAM was developed by Paul Douglas, Jaclyn Marks and Sara Kamins of ED. Among the important features, the proposal abandoned the Existing FIT fixed price approach, instead proposing to use a market-based competitive auction mechanism to set the price paid to each energy seller.

By ruling dated August 27, 2009, the ED-recommended pricing proposal titled "Supply-Side Renewable Distributed Generation Pricing Proposal" was filed and served on parties for comment. Parties were also provided an opportunity to file final comments on pricing approaches, structures, designs and issues. Dates were set for comments and motions.

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5 Reply Comments were filed by PG&E, SCE, DRA, GPI, CARE, Environmental Council, RR, CALSEIA, Solar Alliance and Vote Solar (jointly). These reply comments are referred to herein as the Terms and Conditions Reply Comments.

6 Opening Briefs were filed by PG&E, SCE, SDG&E, DRA, California Attorney General (AG), GPI and Sustainable Conservation (jointly), Santa Monica, FuelCell Energy and CALSEIA (jointly), Cogeneration Association of California (CAC), Energy Producers and Users Coalition (EPUC, joining in the brief of CAC), Solar Alliance and Vote Solar (jointly).

7 Reply Briefs were filed by PG&E; SCE; DRA; CAlifornians for Renewable Energy, Inc. (CARE); IEP; CEERT; Vote Solar; SFUI; and FuelCell Energy and CALSEIA (jointly).

On October 19, 2009, comments were filed and served by 24 parties.[8] On October 26, 2009, reply comments were filed and served by 18 parties.[9] No hearings were requested on any of the issues, and no hearings were held.

3. The Need for a Simplified Procurement Process for Small Generators

The inquiry initiated by the June 2008 Amended Scoping Memo and Ruling began with the question of whether or not to expand the Existing FIT program from 1.5 MW to 20 MW. The desirability and need for a procurement mechanism to address the 1.5 MW to 20 MW market segment – which are still considered smaller generators – depends upon whether the current RPS bid solicitation and contract negotiation process is adequate for procuring smaller projects. If the annual procurement process is not adequate for smaller RPS projects, the Commission should consider whether these projects provide a particular value to the market, utilities, ratepayers and regulators, and whether these projects should be pursued through a more targeted procurement process.

Parties present differing views on the efficacy of the current RPS program for small projects. For example, Environmental Council, CEERT, DRA, First Solar, GPI, IEP and others assert that the RPS program is currently not working

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[8] Comments were filed by PG&E; SCE; SDG&E; DRA; TURN; CARE; GPI; SFUI; CEERT; Santa Monica; FIT Coalition (FIT Coalition); L. Jan Reid (Reid); CALSEIA; Vote Solar; Solar Alliance; First Solar; IEP; Axio Power, Inc. (Axio); Recurrent; GreenVolts; FuelCell Energy; California Energy Storage Alliance (CESA); and Sempra Generation (Sempra). Separate joint comments were filed by PG&E, SCE, SDG&E, Solar Alliance, GreenVolts, Sierra Club and Reid. These comments are referred to herein as Pricing Comments.

[9] Reply Comments were filed by PG&E, SCE, DRA, TURN, GPI, SFUI, Reid, Sustainable Conservation, Sierra Club, Santa Monica, AReM, CALSEIA, Vote Solar, Solar Alliance, Recurrent, FuelCell Energy, CESA, and Fortistar Methane Group (Fortistar Methane). These reply comments are referred to herein as Pricing Reply Comments.

successfully for small projects, while TURN initially argued that it is successful and no change is necessary.[10] Nonetheless, there is considerable agreement that it is feasible and desirable to streamline the process for smaller projects.

Many parties[11] also argue that renewable system-side distributed generation (DG) projects that interconnect on the utility side of the meter[12] present unique value to California ratepayers that is not captured in the annual RPS solicitations. According to CalSEIA, these benefits include: rapid development timeline, electricity production close to demand, reduced congestion on distribution feeder line circuits, reduced demand for peak power, job creation in a local community, and compliance with the state's renewable energy targets.[13] CEERT similarly states, "These [system-side DG] projects are critical to rapid deployment of renewables because of their shorter development timelines, minimal site control and permitting constraints, and proximity to load."[14] CESA also notes that DG located near load centers should play an increasing role in the California RPS because they face fewer permitting and siting problems than central station RPS facilities.[15] Solar Alliance's comments, consistent with Energy Division staff's findings in its 33% RPS Implementation

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[10] TURN initially argued in its Terms and Conditions Comments that an expanded FIT was unnecessary, but in its comments on the Staff Pricing Proposal, TURN stated its support for a more streamlined and expedited process for small projects since they can not effectively participate in RPS solicitations.

[11] CEERT, CESA, FIT, Solar Alliance/Vote Solar, First Solar, CalSEIA, and the Community Environmental Council.

[12] Referred to as "system-side DG" in this decision

[13] CalSEIA Terms and Conditions Comments at 2.

[14] Terms and Conditions Comments at 2.

[15] Pricing Comments at 2.

Report[16], say that smaller RPS projects can "act as an important hedge or safety valve for the RPS to meet the 20% and 33% goals, should the larger RPS projects not come on-line at the pace that is expected."[17]

We agree that it is desirable to simplify the procurement process for relatively smaller RPS projects and that these projects provide unique value to the RPS program because of their potential to be deployed quickly with a relatively smaller environmental footprint and minimal transmission need. Such streamlining should also facilitate development of projects up to 20 MW by mitigating costs and administrative burdens on projects, developers, utilities, and regulators. Further, the majority of parties support a simplified procurement process if there is the right balance of terms, conditions, and prices. We agree. All elements of the procurement process must be considered, and we do so in adopting the right balance of terms, conditions, and prices here in the form of the RAM.

4. Pricing Approach – The Renewable Auction Mechanism

4.1. Background

The Existing FIT for projects up to 1.5 MW uses a fixed price set by the Commission, equal to the MPR, and stated in a published tariff. For the RPS annual solicitations, sellers submit bid prices to a utility and these prices are subject to negotiations, which can take up to a few years, before the contract is finalized. The initial inquiry into expanding the Existing FIT in the June 2008 Amended Scoping Memo and Ruling did not separately scope pricing as an issue. In August 2009, ED proposed that the price for the new program be

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[16] For the complete report, see http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[17] Pricing Comments at 3.

established by use of a market-based competitive auction mechanism – the RAM. The RAM employs an auction, wherein sellers which meet certain minimum criteria are eligible to submit non-negotiable price bids. The buyer then selects winning sellers based on the lowest priced bids first, and signs non-negotiable standard contracts with the winning sellers, incorporating the prices bid by that seller. The cost of RAM, as proposed by ED, would be contained with an authorized revenue requirement for the program.

The Staff Proposal suggests that using an auction to set contract prices may induce developers of system-side renewable DG to bid the lowest prices they would be willing to accept to develop renewable energy projects. This mechanism would also allow the state to pay developers a price that is sufficient to bring projects online but that does not provide surplus profits at ratepayers' expense.

4.2. Parties' Positions

In response to ED's proposal, parties argue in favor of two primary pricing methodologies: (1) fixed and published rates; or (2) contract prices established via a market.

Several parties advocate for an administratively determined fixed-rate FIT.[18] In support, they assert a fixed rate set in advance in a published, publicly available tariff makes the price transparent and easily known to all stakeholders. In their view, the advantages of this approach include providing price certainty for project evaluation and cost recovery, reducing transaction costs, moderating program administrative costs, and protecting ratepayers against excessive prices.

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[18] These parties include FIT Coalition, Santa Monica, SFUI, CALSEIA, GPI, IEP, CEERT, Solar Alliance and Sierra Club.

Other parties recommend a fixed rate FIT for projects up to a certain size (e.g., 3 MW in Senate Bill [SB] 32[19]), and the RAM for larger projects.[20] Among the reasons in support, advocating parties say this approach provides transactional efficiencies for the smallest projects, employs the latest guidance from the legislature, and secures the benefits of competitive markets for relatively larger projects.

Many parties support setting the price for the new procurement mechanism through ED's proposed auction approach – the RAM.[21] In their view, this approach, where bidders receive the price they bid, captures changing market prices in a timely way, is easy to implement, and can provide competitive market prices for ratepayers, IOUs, and sellers. TURN, for example, supports RAM over an administratively set fixed-rate program since RAM "provides greater developer certainty to promote DG projects while minimizing the potential for significant windfall profits at ratepayer expense."[22] Solar Alliance argues that RAM's competitive process drives down electricity costs, which can offer ratepayers rapid price adjustments.[23] Further, Recurrent prefers RAM over a fixed rate because it avoids the ratepayer backlash of setting the rate too high, as occurred in Spain and Italy.[24]

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[19] Stats. 2009, ch. 328

[20] This is a primary recommendation for some, and an alternate recommendation for others, including DRA, GreenVolts, Axio and CARE.

[21] These parties include PG&E, SCE, SDG&E, Recurrent, Reid, TURN, Solar Alliance and Vote Solar.

[22] Pricing Comments at 1.

[23] Pricing Comments at 11.

[24] Pricing Comments at 2.

4.3. Discussion

4.3.1. Policy and Practical Considerations

The RPS statute and program were conceived, initially designed, and remain focused on the renewable market segment being competitive. We use this preference in our consideration of the appropriate RAM pricing mechanism. In addition, as discussed in Section 3, we see the need to adopt a new procurement tool that simplifies the procurement process for the system-side renewable DG market. To accomplish this objective, and to design an efficient and effective program, the pricing mechanism should satisfy staff and parties' policy and administrative priorities. These goals include, but are not limited to: 1) lowering transaction costs for the buyer, seller, and regulator, 2) executing contract prices that are financeable for the developer but also not an overpayment from a ratepayer perspective, 3) the ability to respond quickly to market changes, and 4) promoting the development of a long-term sustainable market.

No party suggests that prices for this program be negotiated in the same manner as the annual RPS solicitations. We agree. We have already determined that the transaction costs of submitting bids that are subject to further negotiations is not appropriate for the smaller system-side DG market.

Both Energy Division's RAM proposal and party comments supporting a fixed-rate FIT argue that their respective approaches will reduce transaction costs. RAM opponents assert that the cost of bid preparation can be significant, while it is zero under a fixed price FIT. However, no credible estimates are presented on the cost of either approach, and we are not convinced that the costs differ significantly.[25] Even with a fixed price program, a rational project developer must have some level of understanding about the economics of the project, including a price or range of prices that is likely to make the project economic. The RAM adopted here does not permit negotiation over price, terms, or conditions. Under these circumstances, there is minimal cost to put a bid on paper, and no transaction cost related to price negotiation. Thus, we are not persuaded by a qualitative argument that the cost of RAM bid preparation is burdensome as compared to preparing a project for a fixed price program.

We also consider the regulatory cost of determining the appropriate fixed price to put in a published tariff. There are costs for data collection and analysis. IOUs, parties, and staff will incur costs to participate in Commission proceedings, the outcome of which may be appealed. The time and cost of an administrative process to set a fixed price is not zero, and could be the same as or more than the sum of all bid preparation costs. Accordingly, we find that the price as bid and standard contracting aspects of RAM would reduce transaction costs for the seller, utility, and regulator.

Next, we evaluate whether the fixed price approach and/or the market-based RAM proposal result in contract prices that are reasonable – i.e. financeable to the developer and competitive for the ratepayer. Advocates of a fixed-price approach contend that a published fixed price FIT is necessary for relatively small projects because it provides certainty for project evaluation and cost recovery, which will increase investor certainty and facilitate simpler

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[25] Recurrent convincingly says: "The developer resources required to bid for these projects through an auction process are a small percentage of the projects' total expense and certainly should not present an insurmountable obstacle for responsible developers, whether small or large, who are willing to make the investment and take the development risks that these projects entail." (Pricing Reply Comments at 2.)

financing. RAM provides a similar result. This is the case because a rational bidder will bid no less than its best cost estimate. Whatever it elects to bid (i.e., its cost or higher), this information gives the bidder adequate certainty to do an economic evaluation of its project.[26] If the bid is later selected, the rate is set and known over the life of the project, and is reflected in a long-term contract with a creditworthy off taker. This process gives reasonable certainty to projects for the purposes of both initial evaluation and subsequent cash-flow for cost recovery.

In addition, unlike an administratively established fixed price, however, RAM also balances the ability for a small project to secure financing and attain a reasonable price, with the assurance that the ratepayer is not overpaying. Parties are concerned that a fixed price could result in ratepayer backlash if the price is set too high, as occurred in Spain and Italy.[27] We agree that there is potential for a fixed price to be set too high or too low, and either option could create financial and regulatory uncertainty. If the price is too high, it would be unreasonable for ratepayers. If it is too low, no projects would be built.

Recurrent attests to the reasonableness of a RAM mechanism for projects in the 1 to 20 MW range. Recurrent reports that it is an independent power producer successfully developing projects via auctions in this size range. Recurrent welcomes the healthy competition that an auction can stimulate and which, according to Recurrent, brings value to IOUs, ratepayers, and society. In response to parties who express concern that small sellers are unduly burdened by market mechanisms, Recurrent states:

> As one of those "small sellers" that concern these parties, Recurrent Energy categorically disagrees that competing in a

[26] Our adopted program does not permit price negotiation.

[27] TURN, Recurrent Energy, Vote Solar, and the Solar Alliance (Pricing Comments).

> RAM is unduly burdensome, unreasonably costly, or somehow unfair. … We are much more concerned by the specter of administrative price-setting gone bad, than by the need to compete through an auction process to meet our buyers' need.[28]

Recurrent opposes a fixed price based FIT, saying that:

> … [S]etting too high an energy rate (by accident or design) at the expense of utilities, ratepayers and society can result in hostility to solar development that undermines the longer-term stability of our markets.[29]

We endorse healthy competition and seek to avoid regulatory approaches that result in hostility from ratepayers or undermine long-term market stability. We also look for an approach that can quickly respond to changes in cost (both increases and decreases). Administrative determination of contract prices is less likely to be as responsive to cost changes than is a seller determining the price it wishes to seek in an auction based on its understanding of the underlying project costs, and changes in those costs.

By allowing developers to bid in their price and also eliminating further price negotiations, the RAM appropriately balances the goals of maintaining a competitive market and reducing transaction costs for small renewable projects. We note that experience to date in the California Solar Initiative, as well as SCE's Solar Photovoltaic Program and the Renewables Standard Contract (RSC) program suggests that the market for smaller scale projects appears robust with a significant number of competing sellers. However, as discussed later, we adopt necessary safeguards to protect stakeholders from adverse outcomes in case the market is not sufficiently competitive to reach optimal results. Those safeguards

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[28] Recurrent Pricing Comments at 5-6.

[29] Recurrent Pricing Comments at 11.

include a cap on total program capacity that can be submitted for simplified contract review, IOU discretion to procure less than the authorized cap in instances of market manipulation or uncompetitive pricing, and ongoing monitoring and reporting. Additionally, the Commission retains discretion to reject contracts submitted for its consideration pursuant to this program if they are not found to be in ratepayers' interests.

4.3.2. Jurisdictional Considerations

When commenting on contractual terms and conditions, a number of parties opined that the Commission has no jurisdiction to establish a fixed rate FIT. By ruling dated May 28, 2009, parties were directed to file briefs on this legal issue. In summary, there is significant dispute among the parties regarding the Commission's jurisdiction to set a fixed price FIT. There is, however, no dispute that the Commission has jurisdiction to set prices at avoided cost for IOU purchases from qualifying facilities (QFs) pursuant to § 210 of the Public Utility Regulatory Policies Act (PURPA.).[30] Further, there is no dispute that the Commission has jurisdiction to rely on a market-based mechanism to set prices. Thus, to avoid this legal dispute and implement a new procurement mechanism as quickly and efficiently as possible, the Commission may either comply with PURPA and establish an avoided cost price, or it may adopt a market-based approach. If it pursues the first option, the Commission could develop a fixed price tariff applicable to QFs at avoided cost, and implement the recommendations of the attorney general and others to update avoided costs for new market conditions and additional factors.

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[30] 16 U.S.C. § 824a-3 (2006); *see generally* 16 U.S.C. § 2601 *et seq*. (2006). This authority was most recently affirmed in Order on Petitions for Declaratory Order, 132 FERC ¶ 61,047 (July 15, 2010).

PG&E and several parties assert that RAM avoids the jurisdiction question. PG&E states:

> The proposed auction process would resolve the issue parties briefed previously in this proceeding; namely, whether the Commission has authority to establish prices for wholesale energy sales in interstate commerce … The RAM, by employing a competitive solicitation, should yield market-based prices and avoid the issue of Commission jurisdiction to set prices in the wholesale generation market.[31]

SCE says the Commission's authority is to set FIT prices either (a) at avoided costs for QFs or (b) to "use a market-based pricing structure."[32] SCE describes RAM as providing "a competitive, market-based mechanism which appropriately looks to the market for pricing."[33]

IEP points out that we have for several years required IOUs to undertake competitive solicitations to procure conventional and renewable resources. The results do not conflict with the Federal Energy Regulatory Commission's (FERC) jurisdiction, according to IEP, precisely because the solicitations produce market-based prices.[34] IEP concludes:

> …no conflict with FERC's jurisdiction is created if the Commission requires or encourages the utilities to pursue competitive solicitations for specific products. In this approach, the Commission acts within its jurisdiction by requiring or encouraging a competitive approach to the products that might be the focus of a feed-in tariff and by accepting the market-based prices that result from that competitive procurement. The

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[31] PG&E Pricing Comments at 4.

[32] SCE Pricing Comments at 4.

[33] SCE Pricing Comments at 6.

[34] IEP Reply Brief at 4.

resulting prices are just and reasonable and are authorized by FERC through its market-based rate authority.[35]

We agree with these parties. Under RAM we do not set the price, but rely on a market-mechanism that is compatible with FERC's rate-setting in wholesale markets. RAM avoids or eliminates the jurisdictional issue, and we adopt it, in part, for precisely this reason.

The reasonableness of this approach, however, relies on a critical assumption: the market is and remains sufficiently competitive to produce just and reasonable rates, result in efficient and optimal outcomes, and protect both buyers, sellers, and ratepayers. We address competitive aspects of the market when we discuss Commission oversight of the RAM program and appropriate ratepayer protection mechanisms.

5. Must-Take Requirement

The Existing FIT is a must-take obligation based on a first-come first-served basis at a known price (MPR) up to a program limit. It includes a wait-list for additionally interested developers. ED's original proposal would require each IOU to have an auction soliciting projects up to 10 MW for up to 1,000 MW, and allow IOUs to solicit projects from 10 to 20 MW.[36] ED's proposal recommended that the total cost of procurement for projects up to 10 MW would be limited by a revenue requirement cap, so that utilities must accept all bids for projects up to 10 MW, starting with least cost projects first, until the revenue requirement cap or capacity cap is exhausted, whichever comes first.[37] All other procurement would be voluntary.

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[35] IEP Reply Brief at 4.

[36] March 2009 Proposal at 5.

[37] August 2009 Proposal at 8.

The proposed decision would have required the utilities to solicit eligible projects up to 20 MW and accept all bids offered through RAM up to a pre-established price and a capacity cap. Parties dispute the legality of this approach based on both federal and state law.[38] The federal law issue is rendered moot in this decision because we preserve the IOUs' discretion to reject bids in instances of market manipulation or non-competitive pricing compared to other renewable procurement opportunities. See Section 6.3 for details on project bid selection.

6. Utility Applicability

ED proposes limiting RAM to the three largest IOUs. We agree.

In comments to the Proposed Decision, SCE and SDG&E argue that they should be able to separately design and offer their own procurement programs that target the same market sector, instead of using RAM. SCE also suggests that

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[38] PG&E, SCE, and SDGE assert that a requirement to procure all bids up to a pre-established price set at the market price referent plus a 50% premium violates state and federal law. They argue that it violates state law (Pub. Util. Code Section 399.15[d]) which sets a limitation on the IOUs' obligation to procure renewable energy at above-MPR costs. They also argue that it violates federal law because it would require them to purchase power at a rate above avoided cost.

FIT Coalition, Vote Solar, Solar Alliance and IEP oppose the IOUs' arguments about the legality of the proposed decision. For example, Vote Solar opposes the IOUs' arguments about state law and contends that the IOUs' arguments are based on the erroneous assumption that RAM prices will exceed the MPR. IEP states that the proposed decision does not violate federal law because it would only set targets for the IOUs' procurement of specific products and the contract prices would be determined through a market mechanism.

We disagree with the IOUs' contention that the RAM violates state law. The limitation imposed by Pub. Util. Code Section 399.15(d) on procurement of energy used for RPS compliance at prices above the MPR applies to contracts selected through the IOUs' annual RPS solicitations. *See* Pub. Util. Code Section 399.15(d)(2)(A). State law, however, does not preclude the Commission from using other mechanisms to ensure compliance with California's RPS requirements.

all megawatts procured through its RSC program should draw down on its RAM capacity requirement.

We agree in part. RAM is the Commission's preferred approach for pursuing projects in the 1 to 20 MW size range for all the reasons already stated. As Vote Solar notes, allowing the utilities unlimited discretion in designing their own, utility specific programs poses certain challenges to both independent power producers (IPPs) and the Commission.[39] IPPs must contend with potentially substantial differences in eligibility requirements and contracting terms that were not developed through a transparent Commission proceeding, and the Commission then must evaluate the resulting contracts that have not been substantially vetted to ensure the contracts and underlying projects are sufficiently viable to merit approval. By adopting RAM, we create a program that provides greater consistency and embodies program rules and contracting terms that facilitate relatively quick review via a Tier 2 advice letter. Accordingly, in the interest of promoting competition and streamlining of the administrative process, the utilities should pursue this market segment specifically via RAM. In other words, while IOUs may use RAM, annual RPS solicitations, or other Commission-approved programs such as the solar photovoltaic programs to procure system-side DG projects up to 20 MW, they may no longer use bilateral negotiations or voluntary programs like SCE's RSC.[40]

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[39] Comments on Proposed Decision at 3.

[40] We note that nothing in this decision alters the decisions and obligations related to the utilities' respective solar programs, the existing AB1969 FIT, purchases from QFs pursuant to PURPA, or other programs the Commission has authorized in prior decisions except as specifically identified in this decision.

Nonetheless, we recognize that SCE has recently executed contracts through its RSC program.[41] In the interest of market continuity, SCE may count any of these contracts approved by the Commission towards its capacity cap.[42] See Section 7.1 for details on how SCE can count contracts already executed through SCE's 2010 RSC to SCE's capacity cap. Furthermore, SCE may submit additional contracts resulting from the RSC solicitations that have been conducted to date, however other than those contracts executed as of the effective date of this decision, these contracts will not reduce SCE's obligations under RAM.

SCE, TURN, and Redwood Renewables also argue that the RAM program should apply to all CPUC-jurisdictional load-serving entities (LSEs). Additionally, § 365.1(c)(1) requires the Commission to ensure that "other providers" (which do not include community choice aggregators) are subject to the same requirements applicable to the three largest IOUs that are implemented pursuant to the Commission authority under the RPS program.

Notwithstanding the arguments that the RAM program should apply to all CPUC-jurisdictional LSEs, we will not apply RAM to CPUC jurisdictional LSEs beyond the IOUs. We apply fundamental RPS program basics to all LSEs (e.g., targets, reporting, penalties), including not only the largest IOUs, but also small and multi-jurisdictional utilities (SMJUs), community choice aggregators (CCAs), and electric service providers. We are considering expansion of these requirements to electric service providers (ESPs) pursuant to PU Code

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[41] SCE's press release (November 19, 2010) reports that it has executed 21 contracts for nearly 259 MW from its 2010 RSC program. See http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=7502

[42] We note that these projects are subject to a Tier 3 review process, and the Commission has the authority to approve or reject those projects based on their merits.

§ 365.1(c)(1).[43] In consideration of that expansion, we recognize that Commission requirements regarding specific RPS program elements necessarily vary among LSEs based on the Commission's regulatory authority, responsibilities, and duties with regard to each type of LSE.[44]

With these distinctions in mind, we limit RAM to the three largest IOUs. As CCAs are expressly exempted by § 365.1(c (1), and they have not had an opportunity to comment here, because no CCA was in operation at the time the record was open for comment. We therefore decline to apply any RAM requirements to CCAs at this time. It would also be inappropriate to apply the RAM to ESPs for different reasons. The Commission has no regulatory authority over ESP contracting processes. Such authority extends from the Commission's regulatory rate authority over IOUs, and serves no purpose with regard to ESP contracts since the Commission has no regulatory rate authority over ESPs. In addition, because the ESPs do not submit their contracts to us for approval, and a key benefit and objective of RAM as a procurement vehicle is to provide streamlined contract approval for projects that conform to the RAM eligibility requirements, it is not relevant to the ESPs.

We also do not impose the RAM requirement on SMJUs. SMJUs are not addressed in § 365.1. Further, application of the RAM to SMJUs is impractical given their size. PacifiCorp, the largest SMJU, has been allocated 0.405% (less

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[43] SB 695 (Kehoe), Stats. 2009, ch. 337. Section 365.1(c)(1) directs the Commission to "ensure that other providers are subject to the same requirements that are applicable to the state's three largest electrical corporations…" The provision was triggered upon issuance of D.10-03-022 on March 15, 2010. Pursuant to a Ruling dated March 25, 2010, parties have filed briefs and reply briefs, and a proposed decision was filed in R.08-08-009 on September 10, 2010.

[44] See, for example, D.05-11-025, D.06-10-019, D.08-05-029.

than one-half of one percent) in the Existing FIT program.[45] The total allocation to the four SMJUs combined is 0.599% (less than six-tenths of one percent).[46] Allocation to PacifiCorp (the largest of the four SMJUs) of its share of the 1,000 MW RAM total program adopted here would be about 4 MW (and to all four of the SMJUs would be about 6 MW). PacifiCorp would be allocated about 1 MW (and all four SMJUs would be allocated about 1.5 MW) in each of the four auctions adopted above. We are not persuaded that, as a practical matter, it is rational to apply the RAM program (up to 20 MW per transaction) to each SMJU with allocated shares of 4 MW or less for the total program (and 1 MW or less per auction). We employed this same practical consideration in 2007 when we limited the required FIT offering by the SMJUs in the Existing FIT to 1 MW rather than 1.5 MW. (See D.07-07-027 at 26.) We do so again here.

7. Auction Design

Having decided above to adopt a simplified and standardized contracting program for renewable system-side DG up to 20 MW in the form of RAM and employ an auction mechanism for determining contract price, we next consider specific auction design elements. These include a program capacity authorization, number of auctions per year, project selection criteria, and a simplified contract review process.

7.1. Program Capacity Authorization

7.1.1. Background

In its August 2009 Pricing Proposal, Energy Division suggests that the procurement authorized for the RAM program be capped by a revenue

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[45] 1,013 kW divided by 250,000 kW is 0.405%. (See D.07-07-027 at 9.)

[46] 1,497 kW divided by 250,000 kW is 0.599%. (*Id.*)

requirement.[47] A revenue requirement, or a total program cost cap, would be calculated for each IOU to reflect how much renewable system-side DG each utility needs to procure compared to other renewable procurement strategies. The amount of RAM procurement needed and its associated cost would be based on an evaluation of cost, development risk profile, and development timeframe of each procurement strategy. Since the revenue requirement would reflect the types and costs of resources needed by the utility, it would be reasonable for all RAM contracts signed within that cap to be given a streamlined contract review.

Since it would take some time to implement a methodology to determine IOU renewable DG procurement need, and it must be coordinated with other aspects of IOU procurement planning, the ED's proposal offers that an interim revenue requirement cap reflects an estimated cost of 1,000 MW of RAM procurement over four years.

7.1.2. Party Comments

Several parties support the revenue requirement approach.[48] Two parties oppose the approach.[49] SCE and Vote Solar propose methodologies for calculating a revenue requirement. SCE's recommended approach would use the MPR multiplied by the energy solicited for a particular auction (assuming an average capacity factor for California's renewable energy mix). Vote Solar suggests that the revenue requirement be calculated based on the costs of a proxy technology for each auction, using publicly available information about the cost of that technology (e.g. data from the Renewable Energy Transmission Initiative), multiplied by the energy in MWhs solicited for in a particular auction.

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47 Pricing Proposal at 8.

48 CALSEIA, Recurrent, Solar Alliance, Vote Solar, TURN,

49 DRA, First Solar.

Several parties provide alternatives to a revenue requirement. Both DRA and First Solar propose a hard megawatt capacity cap instead of a revenue requirement. DRA argues that a revenue requirement, while an innovative approach, would be too complex to calculate at this time.[50] First Solar asserts that a firm capacity cap provides more market certainty, and suggests 3,000 MW.[51]

In response to ED's proposed 1,000 MW cap, Solar Alliance, Sierra Club, First Solar, FIT Coalition, LA Community College District, Vote Solar and others argue for a higher or no cap. For example, Solar Alliance recommends a cap of 2,000 MW; Sierra Club recommends 3,000 MW (with all FIT contracts included); FIT Coalition recommends 4,000 MW (with a minimum of 1,000 MW auctioned per year); LA Community College District and Vote Solar recommend no cap (i.e. unlimited).

7.1.3. Discussion

We adopt an interim capacity authorization of 1,000 MW, and allocate this to the three large IOUs using the same allocation used now for the Existing FIT, as shown in Table 1 below. We do this in light of the following considerations.

SCE argues that no cap can be determined in the absence of prices and other variables. We agree that in the long-term we should authorize a capacity amount based on a utility's need for the product and relative costs of the viable alternatives, as recommended by Energy Division's revenue requirement proposal. However, at this time this methodology is not in place and we therefore find that an initial 1,000 MW procurement requirement is reasonable. It

[50] Pricing Comments at 10.

[51] Pricing Comments at 8.

provides an adequate quantity to test the program and mitigates against potential adverse outcomes if the program needs adjustment.

SDG&E asserts that the cap should be 1,000 MW allocated to each IOU, but further limited by an IOU's RPS targets. That is, an IOU should be able to suspend its RAM when its RPS program target is reached. We disagree. RPS program targets are minimums, not maximums. Twenty percent by 2010 is the minimum. An IOU may not procure less than 20% without the potential for penalty, but may procure more than 20% without penalty. Moreover, the risk of over-procurement given the amount of allocated RAM MW is minor (e.g., 81 MW allocated to SDG&E).[52] If over-procurement becomes a serious risk, IOUs may slightly reduce new contracts selected pursuant to the annual solicitation or other programs that do not have specific allocated capacity at this time. We seek relative simplicity here, and capping the program at 1,000 MW subject to further reductions would add unnecessary confusion and complexity.

Parties provide a variety of recommendations on the appropriate cap level, from an unlimited authorization, to support of ED's 1,000 MW proposal. We have had mixed experience with uncapped programs and decline to adopt this expansion without a program limit, at least before we have some evidence of the results. We decline to adopt a higher cap or no cap. The 1,000 MW cap allocated to three IOUs is sufficiently large to provide market opportunities, while being sufficiently small to provide protection against bad outcomes. In the absence of a revenue requirement cap, we agree with DRA and First Solar and adopt a

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52 SDG&E has voluntarily committed to 33% by 2020. (D.08-12-058 at 265). In approving the Sunrise Powerlink Transmission Project, we said we do not take this commitment lightly, and fully expect SDG&E to follow though. (Id.) SDG&E is concerned with the quantity and cost of over-procurement, absent the ability to suspend RAM when its RPS program targets are reached. Given its commitment to 33%, SDG&E's concern is misplaced.

nameplate capacity cap of 1,000 MW to be procured between the IOUs over the next two years. We may adjust our 1,000 MW cap at any time based on evidence of response and need.

If an IOU would like to procure more than its allocated share of the 1,000 MW cap, it may request an increase in its implementation advice letter. If approved by the Commission, the additional capacity can be submitted via the streamlined Tier 2 advice letter process. In addition, we expect the 1,000 MW to be only an initial authorization. After the first authorization is expired, it makes sense to authorize RAM procurement based on a more informed evaluation of a utility's need. While the inputs and methodology are not in place to adopt a revenue requirement cap at this time, we authorize the Director of Energy Division to explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process.

In addition, at any time, the Director of Energy Division may issue a resolution, either on its own motion or in response to a utility advice letter filing to update the cap. A utility advice letter request would need to justify the cap adjustment.

7.1.4. Capacity Allocation

We adopt the same allocation percentages used for the Existing FIT to allocate the 1,000 MW capacity cap as follows:

TABLE 1

TOTAL PROGRAM CAPACITY ALLOCATION

UTILITY	INITIAL ALLOCATION (MW)[53]	PERCENT OF INITIAL ALLOCATION	EXPANDED ALLOCATION (MW)
SCE	247.7	49.84	498.4
PG&E	209.2	42.09	420.9
SDG&E	40.1	8.07	80.7
TOTAL	497.0	100.00	1,000.0

ED recommends that the program cap be allocated to IOUs over four years.[54] We decline to adopt a four-year horizon for this program. Nonetheless, we are concerned about the degree of competition and take reasonable steps to increase the competitive environment in which RAM will operate.

Therefore, each RAM auction shall result in contracts for 25% of the total allocation[55]:

53 This is the total initial Existing FIT allocation (e.g., the sum of the allocation for water/wastewater and other) found in D.07-07-027 at 9, as expanded for SDG&E in D.08-09-033. The four small and multi-jurisdictional utilities (SMJUs) in the statewide total of 498 MW are not included here. (See Background discussion above.)

54 Pricing Proposal at 8.

55 This is subject to the IOUs' discretion to reject contracts based on uncompetitive pricing, as discussed in Section 7.3.

TABLE 2
TOTAL ALLOCATION PER AUCTION

UTILITY	TOTAL RAM ALLOCATION	ALLOCATION FOR EACH RAM AUCTION
SCE	498.4	124.6
PG&E	420.9	105.2
SDG&E	80.7	20.2
TOTAL	1,000.0	250.0

Given two auctions per year (adopted below), the 1,000 MW cap can not be subscribed faster than over a two-year period. It may take longer, depending upon the number of sellers and selected bids per auction. The rate of procurement is an important measure of the interest and success of the program, and will help us judge if and when to change the cap. The 249.2 MW cap per year for SCE compares favorably to SCE's voluntary RSC program cap of 250 MW per year, and is reasonable.

We balance these concerns with the need to assure sellers that is not so small as to limit the number of transactions. To do so, we require each IOU to offer no less than the allocated capacity for each auction.[56] SDG&E, for example, will offer 20.2 MW in each auction.

We make one exception. The exception is that we require IOUs to bring unsubscribed amounts (or subscribed amounts that drop out of the program) to the next auction. That will increase the capacity offer (both maximum and minimum) in subsequent auctions by the amount of the unsubscribed (or dropped) capacity that is brought forward. This will promote seller assurance of the total market size, will assist with meeting California RPS goals, and is

[56] As discussed earlier, an IOU may request an increase to this allocation in its initial implementation advice letter or in a future advice letter filing.

consistent with similar treatment in our two recently authorized solar PV programs.

In addition, if SCE chooses to apply any capacity from already-executed 2010 RSC program contracts (provided they are approved by the Commission), SCE must detail its net capacity allocation in its initial implementation advice letter. SCE must also propose a schedule for soliciting the remainder of its capacity allocation in RAM solicitations over the next two years.

7.2. Number of Auctions Per Year

ED proposes a minimum of two auctions per utility per year, staggered between IOUs throughout the year. Parties present a range of views. We require two auctions per year held simultaneously by the three IOUs for the reasons stated below.

DRA, Reid, and PG&E generally support one auction per year, asserting that multiple auctions are unreasonably costly and time consuming. TURN recommends holding one auction per year at least for the initial two years (asserting that two auctions may be administratively burdensome). TURN says adding a second auction could be based on whether a sufficient number of acceptable bids are submitted. Solar Alliance recommends a minimum of three auctions per year asserting that this will enhance competition and developer knowledge of the new market, thereby resulting in lower bid prices. SCE says the number of auctions should be determined in the long-term procurement planning (LTPP) proceeding, and the auctions be held concurrently with other procurement to promote efficiency and administrative cost savings.

One important advantage of a fixed-price FIT is that it is continuously available (i.e., projects can access the tariff at any time). We lose that benefit with RAM, but in exchange gain potential cost savings from competition. At the same time, we want to minimize the loss of the continuous availability element as much as possible.

We are not persuaded that multiple auctions are unreasonably costly and time consuming. To the contrary, we want the standard contract to be simplified and easy to implement. We want the auctions and winning bid selections to be streamlined. A requirement of more than one auction per year will provide an incentive for IOUs to accomplish this goal.

Therefore, for the initial roll-out of the program, we require two auctions per year. We require the auctions to be held simultaneously by the three IOUs in order to maximize competition. A project may bid into all three auctions. IOUs should propose in their implementation advice letters any methodologies necessary for coordination, including a process for bidders to notify IOUs if they are shortlisted in more than one RAM solicitation.

We expect IOUs, ED, and parties to monitor auctions and make recommendations over time if the number should be changed. We would eventually like the program to be sufficiently routine that auctions may be held even more frequently, if not continuously.[57]

7.3. Project Selection

ED proposes that projects submit a price bid and IOUs make selections on the basis of price by selecting the least expensive projects in each product category. ED recommends that projects of the same product type be compared to each other instead of being compared to all renewable products that participated in the auction. ED proposes that the IOUs predetermine the amounts of

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[57] We have encouraged IOUs to explore and propose continuous procurement pursuant to RPS Procurement Plans, and we encourage IOUs to do the same for the RAM. (See D.06-05-039 at 56 regarding annual RPS Procurement Plans.)

renewable products they intend to solicit in each auction based on the individual IOU's renewable need. ED offers three examples of products: baseload, peaking as-available, and non-peaking as-available. ED proposes that annual RPS procurement plans specify how much of each product the IOU will procure, with selection based on price and limited by a revenue requirement cap for each product category. [58]

7.3.1. Party Positions

Many parties support selection based on price in order to secure the least-costly products with the maximum benefits of price competition. SCE supports the use of an auction to determine the price for each project, but recommends only one RAM energy product, with the selection not made on the basis of price, but made on the other qualitative and quantitative attributes related to a project's costs and benefits. According to SCE, this method permits the IOU to select the best combination of resource types and deliveries; SCE calls this a "value-based selection process." Parties mention other alternatives, such as selection based on project viability or lottery.

As for ED's recommendation to require three distinct products in each auction, parties offer a range of views. SCE says that each auction should be open to all technologies and not limited by specific types of resource categories, such as baseload, peaking as-available, and non-peaking as-available. Others, such as FuelCell Energy, GreenVolts, Inc. (GreenVolts), Sierra Club, and GPI,

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[58] Pricing Proposal at 8.

argue for technology differentiation, asserting that this helps preserve production differentiation and encourages resource diversity.[59]

7.3.2. Discussion

We agree with ED that selection should be limited to price. Bid selection based only on price is reasonable because, as recommended by ED, we authorize an IOU to solicit product-specific megawatts in a quantity that reflects an IOU's portfolio need. In each IOU's RAM implementation advice letter, the IOU will choose what portion of their allocated RAM capacity they will solicit from various product buckets. These product buckets are baseload, peaking as-available, and non-peaking as-available. Also, RAM bid prices must be adjusted by an IOU's time of delivery (TOD) factors before the bids are ranked and selected, so that the project's value relative to the IOU's portfolio is considered. As a result, while we do not adopt SCE's proposal to use additional qualitative and quantitative criteria for bid selection, the RAM program does enable a utility to target products that provide specific value to their portfolio. For the initial roll-out of this program, we allow the utilities to define the products they wish to procure in their implementation advice letter filings. IOUs may choose to procure baseload, peaking as-available, and non-peaking as-available products, or a combination of the products. Once approved, the utilities are to solicit the minimum amounts of products approved through the implementing advice letter.

If an IOU additionally wishes to establish other metrics, such as a seller concentration limit, for the evaluation of RAM bids, it may propose the metric(s)

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[59] GPI recommends cost-of-generation based fixed-price tariffs. (Pricing Reply Comments at 5.) Generation costs vary by technology. A cost-of-generation based fixed-price tariff would therefore require different tariffs by technology.

in its implementation advice letter filing for consideration by the Commission. These metrics must fit within the price-only selection framework established for RAM, and would not, for example, include a proposal to add qualitative adders (e.g. transmission cost adders) to the bid evaluation process.

Finally, we provide the IOUs with discretion to reject bids from an auction under two circumstances: there is evidence of market manipulation, or the prices are not competitive. An IOU may reject an entire auction's results based on such an assessment or reject individual bids even before their allocated capacity cap has been reached. In other words, an IOU may evaluate the supply curve of bids received in an auction and assess whether any of the bid prices are unreasonable and uncompetitive relative to the IOU's other renewable opportunities. If an IOU wishes to utilize this discretion, it shall demonstrate in an advice letter filing to the Commission why bids were rejected before the capacity cap was exhausted.[60]

7.4. Use of an Independent Evaluator

DRA has proposed the use of the Independent Evaluator (IE) to oversee the RAM auctions. We adopt DRA's proposal in order to ensure that the competitive solicitations are administered fairly and properly. The IOUs shall use an IE consistent with and pursuant to the requirements established in D.07-12-052, as modified by D.08-11-008.

D.07-12-052 ordered the IOUs to develop a pool of at least three Ies to use for all long-term solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids, and for all competitive RFOs. D.08-11-008 modified the

[60] If an IOU executes contracts from a RAM solicitation, but not sufficient to hit its capacity cap, then it can justify its decision in its Tier 2 advice letter requesting approval of a portion of the projects. If the IOU terminates the entire solicitation, it must file an advice letter with this rationale without the request for approval of any contracts.

circumstances under which an IOU must retain the services of an IE. We believe this requirement is sufficient to ensure a fair and transparent of solicitation. Each IOU shall provide the IE's reports regarding project solicitations in its annual program compliance report to the Commission or in the advice letter submitting the executed contracts.

7.5. Simplified RAM Contract Review

In light of our objective to establish a simple procurement program that reduces transaction costs for the buyer, seller, and regulator, we propose a mechanism for streamlined contract review through a Tier 2 advice letter filing. As discussed above, in the long-term, the amount of generation procured through allowed a simplified review should reflect a utility's need for renewable resources and the comparative costs of various types of generation to meet that need, as identified through a procurement planning process. However, since this methodology is not yet in place, we now discuss an interim approach to authorize a limited amount of RAM procurement through a streamlined contract review process.

The proposed decision would have established a simplified preapproval threshold (SPT) for Tier 1 contract review. The proposed SPT equaled the appropriate MPR plus a 50% premium. This approach would have required IOUs to procure all RAM bids up to the SPT, allowed all procurement below the SPT to utilize the simplified contract review process, and allowed all procurement at or above the SPT to be filed by Tier 3 advice letter or application. As discussed earlier, parties disputed the legality of imposing a must-take obligation up to the SPT. This issue is rendered moot in this decision because the SPT is eliminated and IOUs are provided the discretion to evaluate whether there is an appropriate price threshold above which bids are not competitive and should be rejected. The simplified contract review mechanism provides that an IOU batch and submit all standardized RAM contracts from an auction in one Tier 2 advice letter for contracts up to the utility's capacity allocation.[61] This will permit simplified review and approval of contracts. We note, however, that nothing in this decision diminishes the Commission's authority to reject contracts that the utilities submit based on the RAM program if the Commission finds those contracts are not in the interest of ratepayers. For those contracts that are approved, this mechanism thereby provides assurance of cost-recovery for the IOU.[62]

8. Eligibility

8.1. Eligible Sellers

The original legislation requiring the Existing FIT,[63] and our initial implementation of that program in D.07-07-027, required that a generator serve on-site load and be an existing retail customer of the utility to qualify for the FIT. The requirement has not been carried forward in SB 32, amending the Existing FIT requirements. It is also not in our existing RPS program (annual bid solicitation), nor is it required in the QF program or as part of the LTPP. We adopt ED's recommendation that the seller need not be a retail customer of the IOU or serve on-site load for consistency with current law and other programs.

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[61] This capacity allocation may equal an IOU's share of the 1,000 MW, more than its share if requested an approved by the Commission, or less in SCE's case if they adjust their cap with RSC contracts.

[62] § 454,5(d)(2). Cost recovery is predetermined to be reasonable and is assured subject to Commission review of IOU contract administration.

[63] Public Utilities Code Section 399.20.

8.2. Project and Transaction Size

The Existing FIT program is capped at 1.5 MW. In this proceeding, we asked parties whether or not to increase the eligible project size from 1.5 MW to 20 MW. At that time, § 399.20 limited the program to projects not more than 1.5 MW, and we adopted that as project size limit. The transaction limit in an excess sales scenario was similarly limited.

In contemplating RAM design, we revisit both the appropriate project size, and the appropriate transaction size. In other words, we examine what size projects can participate in RAM and whether projects larger than 20 MW that offset their onsite load can participate in the RAM by selling their excess power up to a transaction size limit. We conclude that the project and transaction limit be 20 MW of nameplate capacity for projects utilizing either the full/buy sell or the excess sales option. This approach is straightforward and easy to implement, and potentially reduces some of the gaming concerns associated with larger projects breaking up transactions in order to participate in the RAM.

8.2.1. Positions

Parties present a wide range of project sizes that should be eligible as part of a new RPS procurement process for small generators. That range varies from retaining the Existing FIT limit of 1.5 MW per project, to an unlimited megawatt size per project. Parties' positions on the appropriate size of the project sometimes depend on whether the price will be fixed in a FIT or subject to a market mechanism, with several parties advocating fixed FIT prices for smaller projects, and market-based pricing for larger projects.

CARE, AreM, SCE, and others, for example, believe project size should remain at 1.5 MW under a fixed price FIT. However, if based on a competitive market price, CARE supports greater than 3 MW but less than 20 MW.[64] TURN supports 2 MW for a fixed price FIT,[65] or between three and 10 MW if the price is based on an auction.[66] Focusing on a fixed price FIT, PG&E and others argue project size should be limited to 3 MW for several reasons, including recognition of the legislature's most recent guidance in SB 32. SDG&E asserts the risk of system impacts on smaller utilities necessitate a 5 MW limit. ED staff and others recommend a must-take FIT for projects up to 10 MW, with utility discretion to take or reject contracts for projects between 10 MW and 20 MW.[67]

IEP, DRA, Sierra Club, Environmental Council, and others recommend that a streamlined RPS procurement process be available for projects up to 20 MW. GPI and others argue that a must-take FIT should apply to projects larger than 20 MW. GPI prefers a must-take FIT up to at least 60 MW.[68] CEERT says it would eventually "like to see the cap on project size removed so that projects of all sizes may be eligible for the must-take FIT program."[69] LA Community College District does not support a project size cap, believing a FIT should be available to any size project.[70]

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[64] CARE Pricing Comments at 4.

[65] TURN Pricing Comments at 3.

[66] TURN Pricing Comments at 1, assuming SB 32 implementation of a fixed price FIT up to three MW.

[67] In this context, must-take means that the IOU must enter into the standard contract to purchase energy from the generator up to various program caps expressed in MW.

[68] GPI Terms and Conditions Comments at 5.

[69] CEERT Terms and Conditions Comments at 4.

[70] LA Community College District Terms and Conditions Comments at 3.

8.2.2. Discussion

For all projects, whether utilizing the full/buy sell or excess sales option, we adopt a project size limit of 20 MW. We do this as part of our goal to streamline the entire RPS program for smaller RPS generators where feasible and reasonable. This can be done here for projects up to 20 MW. We adopt this limit for many reasons.

The California Energy Commission (CEC) has repeatedly recommended that we study and implement a FIT for projects up to 20 MW.[71] A 20 MW size limit is also consistent with Commission decisions. We have established certain contract provisions for small sellers because we have found it is difficult for them to bid into a utility request for proposal, and they generally do not have the resources or expertise to negotiate and enter into a bilateral contract. We define the size of those small sellers as 20 MW or less. (See D.07-09-040 at 121).

Several existing programs use a 20 MW threshold and those programs influence our decision here. For example, SCE has a standardized contract program for any project using renewable technology up to 20 MW – its RSC program (see D.09-06-018 at 59). SCE says the RSC program addresses difficulties faced by smaller projects (i.e., those up to 20 MW) when they try to

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[71] See California Energy Commission 2006, *2006 Integrated Energy Policy Report Update*, CEC-100-2006-001-CMF, January 2007 at E-6; California Energy Commission 2007, *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CMF, January 2008 at 6; California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, CEC-100-2008-008-CMF, November 2008 at 29; California Energy Commission 2009, *2009 Integrated Energy Policy Report*, Final Commission Report, December 2009, CEC-100-2009-003-CMF at 230.

participate in annual RPS solicitations, and eliminates the need for complex negotiations (see D.08-02-008 at 42-44[72]).

In 2009, PG&E proposed a solicitation as part of its solar PV program for projects up to 20 MW (Application 09-02-019). A 20 MW size potentially has merit in many contexts, and we agree with DRA that PG&E's recommendation that a 10 MW project size limit here is inconsistent with PG&E's proposal for 500 MW of PV installations up to 20 MW for its PV program.[73] We recently approved PG&E's PV program for projects up to 20 MW. (See D.10-04-052.)

State law requires electrical corporations to have tariffs and standard contracts for purchases of electricity from certain customers up to 20 MW (See § 2840 et seq. regarding combined heat and power). Federal regulations draw an important distinction between QFs at or below 20 MW and those above 20 MW, including exemptions from the Federal Power Act for the smaller QFs, and certain assumptions about the smaller QFs limited ability to access competitive markets.[74] Federal regulations have distinguished between generators at or

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[72] SCE recently said of its RSC program for projects up to 20 MW: "Through this program, SCE has sought to remove some of the barriers that smaller projects may have had when participating in SCE's annual solicitations. Such barriers have been especially evident for projects with smaller generating capacities. By offering standardized contracts for smaller projects, SCE hopes to increase opportunities for such projects to execute contracts with SCE and contribute to the State's RPS goals." (Advice Letter 2356-E (July 1, 2009) at 3.)

[73] DRA Terms and Conditions Reply Comments at 7.

[74] 18 CFR 292.309(d)(1) establishes a rebuttable presumption that a QF with capacity at or below 20 MW does not have nondiscriminatory access to the wholesale electricity market. Also see 18 CFR 292.601 regarding certain exemptions from federal and state law for QFs at or below 20 MW.

below 20 MW and those above 20 MW for purposes of interconnection requirements.[75]

SDG&E and several parties argue for a lower project size limit, asserting that large projects may create significant problems with interconnection, grid system stability, or other concerns. Among other things, SDG&E states:

> As project size increases to 5 MW, the probability that system upgrades will be required also increases. As shown in the illustrative example in Attachment A [to SDG&E's terms and conditions Comments], system upgrades that could be required to accommodate projects sized greater than 5 MW would be prohibitively expensive.[76]

Solar Alliance and Vote Solar counter that prohibitive costs deter developers:

> Many of the IOUs' concerns fall by the wayside when one considers SDG&E's acknowledgement (comments at p. 11) that generators are responsible…for interconnection and distribution upgrade costs. In other words, interconnection costs…are likely to be a potent deterrent for developers to interconnect a system beyond what the interconnected distribution system can handle without significant upgrades. This more than adequately addresses SDG&E concern regarding the maximum size limit for projects in SDG&E's service territory. As SDG&E acknowledges (comments at p. 11), '[p]rojects sized above 5 MW are likely to require significant system upgrades…making such projects poor candidates for the FIT Program.'[77]

We are not convinced that project size must be limited because of system reliability or interconnection cost concerns. Each project, regardless of size, must

[75] For example, see SCE 2009 RPS Procurement Plan Request for Proposals at Section 7.04.

[76] Terms and Conditions Comments at 5-6.

[77] Joint Terms and Conditions Reply Comments at 3.

successfully navigate the interconnection process, including cost allocation, before it can be interconnected. Synchronized operation is not permitted unless and until the system may be operated safely, and projects that will cost too much to interconnect will not be pursued. The evidence demonstrates that existing interconnection requirements adequately address these concerns for all projects, including those 20 MW or less. For all these reasons we find smaller projects, defined here as 20 MW or less, should be eligible for the new RAM procurement program adopted here. IOUs should proposed in their bid protocols how to prevent sellers from breaking up or subdividing larger projects to circumvent the 20 MW project size limit.

8.3. Full Buy/Sell or Excess Sales

PG&E, SCE, and SDG&E must offer Existing FIT customers the choice of selling electricity under an arrangement of either (a) full buy/sell or (b) excess sales (see D.07-07-027 at 33-38. [78]) In a full buy/sell transaction, a renewable facility would sell 100% of its generation to the utility. In an excess sales agreement, a facility would first offset its onsite load and sell its excess generation to a utility.

ED proposes that the RAM be available only as a full buy/sell transaction, asserting that the excess sales option fails to provide the IOU with sufficient certainty regarding the expected output from the project and undermines the IOU's ability to conduct long-term procurement planning.[79]

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[78] The other four utilities (PacifiCorp, Sierra, Mountain Utilities, Bear Valley) must offer to purchase pursuant to full buy/sell, and may offer to purchase via excess sales.

[79] March 2009 Proposal at 9.

8.3.1. Party Positions

CalSEIA, SCE, PG&E,[80]and DRA support the full buy/sell approach. Solar Alliance, IEP, TURN, CEERT, GPI, FuelCell Energy, Sustainable Conservation, SFUI, Redwood Renewables, and Environmental Council support having the option of either (a) excess sales, or (b) the customer having the choice of either full buy/sell or excess.

8.3.2. Discussion

We are convinced by GPI, TURN, and others that ED's concern is unfounded. GPI correctly contends, for example, that the effect on the integrated electrical system is the same regardless of the type of sale agreement.[81] That is, the renewable generator output and the host-site load will exhibit the same levels of variation despite the type of sale arrangement with the IOU, and there is no evidence to show that the output and load are influenced by the type of sales arrangement.[82] TURN correctly states that IOUs are capable of reasonably accurate forecasts and have routinely made such calculations in many Commission proceedings. TURN concludes that: "There is no specific reason why providing compensation for net excess sales complicates such forecasts or undermines the accuracy of long-term resource planning."[83]

Because there is no technological impediment, and because it meets certain state policy goals, we continue the approach of the Existing FIT by allowing the

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[80] PG&E supported the excess sales option in the March 2009 Proposal, but changed its position to supporting the full buy/sell option in its comments on the proposed decision.

[81] Integrated system planning, for example, can be successfully performed whether electricity generation is on the "customer side" or the "utility side" of the meter.

[82] Terms and Conditions Comments at 3.

[83] Terms and Conditions Comments at 6.

generator to choose either full buy/sell or excess sales. First, the choice of either full buy/sell or excess sales has been available to QFs since 1979. No evidence has been presented that this policy has been unworkable over the last 30 years. Second, in D.07-07-027, we adopted both options for the Existing FIT.[84] Thus, we allow both the full buy/sell and excess sales transactions for the RAM. For both types of transactions, the full project capacity should apply to an IOU's capacity cap.

8.3.3. Location of Facilities Eligible for The RAM

Parties take a wide variety of positions on where a project must be located to be eligible for the RAM – from IOU service territories to the entire CAISO control area. The IOUs support the geographic restrictions of the Existing FIT, wherein generators sell to their interconnecting utility. ED recommends that projects eligible for the RAM program be located within the CAISO control area to facilitate interconnection of projects that efficiently utilize California's distribution and transmission system.

The proposed decision would have allowed any RPS-eligible generator to bid into RAM. That is, all facilities interconnected to the Western Electricity Coordinating Council (WECC) could participate in any of the IOUs' RAM auctions. No parties supported this position.[85] Most parties support limiting eligibility to projects located within California, to California's distribution

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[84] We dismissed SCE's application for rehearing of D.07-07-027 on this subject. In doing so, we concluded that the two sales options are consistent with the plain language of the FIT statute. We also said that the two options further the statutory intent of promoting reasonable development of renewable resources to meet multiple state objectives. The two sales options continue to do so, and should be adopted in the RAM to facilitate the same objectives.

[85] Specifically, Axio, DRA, CARE, FCE, FIT Coalition, enXco, Recurrent, SFUI, SDGE, Solar Alliance, and TURN oppose a WECC-wide approach.

system, or to a utility's service territory. In support of requiring distribution-level interconnection, TURN notes, "The original purpose of the RAM was to provide streamlined market opportunities for distributed generation projects connecting to preferred locations within IOU service territories."[86]

We agree that RAM eligibility should be limited to the utilities service territories. RAM provides a specific and well-defined value to ratepayers because small system-side RPS projects that connect to utility service territories incur none of the additional costs associated with some other forms of renewable generation. For example, these expenses may include costs to construct new transmission lines for more remote generation facilities and the expense of firming and shaping transactions for generation that can not be delivered directly to a CA balancing authority area. If projects located outside IOU service territories were included in RAM, then the price-only project selection criteria may not be applicable. Instead, IOUs may have to add transmission and/or firming and shaping adders to the market valuation of bids to evaluate the projects on an apples-to-apples basis. Thus, RAM enables more streamlined RPS program administration by requiring bid evaluation based on price only, which does not allow for other qualitative adders which are used to assess and rank bids' value in the annual RPS solicitations.

Accordingly, we will allow any projects located within PG&E's, SCE's, and SDG&E's service territories to participate in RAM and bid into one or more of the IOUs' RAM auctions. If a project is selected in more than one auction, however, it must notify all affected IOUs which one shortlist it will accept within 10 days of its notice that it was selected in multiple auctions.

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[86] TURN Comments on PD at 7.

Finally, we reject a Sierra Club proposal to give community choice aggregators (CCAs) and energy service providers (ESPs) the right of first refusal for electricity from an RPS project in their service areas.[87] We seek to promote, not limit, competition. Tipping the scale in favor of CCAs or ESPs would unreasonably constrain the competition upon which this market is premised.

9. RAM Standard Contract

9.1. Contract Negotiations

ED proposes that RAM standard contract terms and conditions not be negotiable. Similarly, bid prices should not be negotiable.[88] We agree.

We streamline procurement with the RAM by adopting a standard, non-negotiable contract for each IOU, a program capacity cap, a market mechanism to determine contract price, and other standardized protocols. The result is to provide IOUs, project developers, and the Commission a simplified approach to accessing a market segment that can contribute substantially to meeting the state's RPS, GHG, and other goals. This makes it relatively easier and less costly for all stakeholders.

We decline to allow negotiations within the RAM since this will add time, cost, and complexity to the RAM program. Buyers and seller in this market segment have other opportunities that permit negotiations if and when necessary, in the form of the annual RPS solicitation. In this context, it is reasonable to make the RAM program "take-it-or-leave-it" (non-negotiable). To allow for contract negotiations is, in our view, in conflict with the goals of this program which is to provide a streamlined approach to renewable procurement for smaller scale RPS projects.

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[87] Terms and Conditions Comments at 12.

[88] August 2009 Proposal at 9.

9.2. RAM Contract Terms and Conditions

ED proposes that each IOU start with its Existing FIT contract and add or amend terms as needed to develop RAM, with the three IOUs having consistent terms and conditions for the new terms. ED recommends that a uniform standard contract for all three IOUs be required over time. Parties dispute the need and desirability of uniformity, with IOUs generally in opposition and some parties in support.

While we appreciate ED's desire for uniformity across each of the IOUs' RAM contracts – with one uniform contract the goal – we decline to require such rigid uniformity here. We will allow each IOU to develop its own standard contract, which will be non-negotiable and standard for all winning bidders in a specific RAM auction. We also decline to identify which contract each IOU should start with in developing a standard RAM contract. We do strongly encourage the IOUs to begin with an existing standard contract that is simple, currently in use, and that has been vetted through a stakeholder process. Each IOU shall include its proposed standard contract as part of its advice letter filing implementing RAM, as described in Section 12.1 below. While we do not mandate a uniform contract, there are some basic elements within those contracts that we require to be the essentially the same, as described in the section 9.3 below.

We now discuss specific contract terms and conditions raised by ED and addressed by parties. If not addressed in this decision, we allow the IOUs to propose contract terms and conditions, subject to Commission approval through an advice letter.

9.2.1. 18-Month Commercial Operation Date

The Existing FIT provides that a project must be operational within 18 months or the contract is subject to termination. Termination is not automatic. The IOU must provide notice and opportunity for parties to address termination before termination becomes effective. If unable to reach agreement on a reasonable schedule, the IOU may move forward with termination. (See D.07-07-027 at 38-40.)

For RAM, ED proposes automatic contract termination after 18 months, with developer forfeiture of the proposed project development security deposit. A one-time six-month extension may be permitted, according to ED's proposal, if the project can successfully demonstrate the cause of the delay is due to regulatory processes outside of its control such as permitting or interconnection delays not caused by the developer. ED recommends that delay due to business risk, such as lack of financing or equipment delivery delay not be an acceptable justification for the granting of an extension. If terminated, ED says the project may participate in another RPS opportunity, such as the next RAM auction or annual competitive RPS solicitation.[89]

9.2.1.1. Party Positions

Parties offer a range of views on the proposed 18-month commercial operation date, and possible extensions. CEERT and some parties support ED's proposal in part or whole. CALSEIA says projects over 5 MW may need more time to obtain permits, and recommends considering a longer timeframe combined with project milestone requirements.[90] PG&E suggests specific times frames, with extensions at the discretion of the IOUs, but proposes that

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[89] Pricing Proposal at 8-9.

[90] CALSEIA Terms and Conditions Comments at 4.

termination only occur when there are true constraints, such as the program cap or transmission or distribution limits.[91] FuelCell Energy does not object to ED's proposal as long as an appropriate force majeure clause covers events outside the parties' control.[92] GPI opposes the 18-month provision, asserting it is unnecessary and harmful unless the program cap is a binding constraint that is actually limiting other projects' participation in RAM.[93]

IEP contends that ED's recommended strict 18-24 month requirement will limit eligibility to projects that (a) are already interconnected or have strong assurances that no upgrades will be required and (b) have already completed permitting. IEP says this will considerably shrink the universe of potential projects because developers will be required to make significant financial expenditures before they can sign a contract. Moreover, few lenders will agree to finance a project that will lose its contract if it encounters even ordinary construction delays. IEP suggests the cure for these concerns is to allow the project 18 months after contract signing to begin material on-site construction.

In the alternative, IEP suggests that technology-specific timelines may be established in recognition of the different degrees of construction and permitting complexity associated with different renewable technologies.

9.2.1.2. Discussion

We think there is merit in a strict length of time provision for RAM, not unlike in the Exiting FIT. This streamlines RAM administration and attracts projects that are more viable because they are further along in the project development process. We find that the best approach is to set meaningful time

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[91] PG&E Terms and Conditions Comments at 8.

[92] FuelCell Energy Terms and Conditions Comments at 3.

[93] GPI Terms and Conditions Comments at 4.

limits, subject to one justifiable extension. Therefore, we adopt an 18-month timeframe, with the potential for one six-month extension. The 18-month deadline begins upon contract execution between the IOU and the seller. We expect the IOU to limit the reasons for an extension to regulatory delays outside of the developer's control. In order to grant an extension due to regulatory delays, the project, for example, must show that it filed applications timely, paid fees timely, and is responsibly pursuing the necessary applications. An IOU should terminate a contract at the end of 18 months if the project fails to adequately demonstrate the merits of an extension.

We expect ED and parties to monitor IOU extensions, and take them into consideration as part of future recommendations relative to IOU administration of the RPS and RAM programs.

We do not adopt IEP's proposal that we move the critical milestone deadline from commercial delivery to the commencement of material on-site construction. The record does not contain a definition of material on-site construction, and we decline to develop one. Disputes are likely even if the term is defined. Therefore, changing the deadline from commercial operation to material on-site construction does not resolve the issue.

Similarly, we decline to adopt technology-specific timelines that recognize the different degrees of construction and permitting complexity associated with different renewable technologies. The establishment of any timeline requires judgment, and legitimate delays can occur relative to any timeline. Technology-specific timelines do not resolve the issue.

9.2.2. Development Deposit

The Existing FIT does not require a development deposit. ED proposes that the RAM require a development deposit of $20/kW. ED recommends that this deposit is either (a) refunded once the project is operating or (b) applied to the subsequent performance deposit.

9.2.2.1. Party Positions

In response to ED's proposal, parties recommend a range of development deposits from zero[94] to at least $30/kW.[95] Recurrent recommends increasing the deposit to at least $30/kW in order to strengthen project and developer viability requirements. Opponents assert that even a small deposit is an unnecessary barrier, but provide no evidence. On the other hand, SCE shows that a $20/kW deposit is less than 1% of an estimated minimal $2,100/kW installed cost for the least expensive renewable project.[96]

Several parties argue that the pay-for-performance feature of paying only for the delivered product provides sufficient incentive for a developer to bring its project to successful commercial operation, and no additional incentive is necessary. Sustainable Conservation argues there should be no development deposit since it is already a significant challenge to obtain project financing and a project should not have to raise additional capital just to hold a place in the queue.[97]

9.2.2.2. Discussion

We recognize that a development deposit is appropriate because IOU costs relative to a failed project are not zero (e.g., there are costs to obtain replacement power). In addition, because the renewable goals are finite, it is important to

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[94] See, for example, Sustainable Conservation Terms and Conditions Comments at 7; Redwood Renewables Terms and Conditions Comments at 5.

[95] See, for example, Recurrent Pricing Comments at 7.

[96] SCE Terms and Conditions Reply Comments at 5.

[97] Sustainable Conservation Terms and Conditions Comments at 7.

take steps to ensure more viable and credible projects are selected as those projects that are selected necessarily crowd out other opportunities. To the extent putting capital at risk in the form of a security deposit will screen more speculative projects out of the solicitation, it is to ratepayers' benefit to require such deposits. This needs to be balanced against the risk that if set too high, we will exclude projects that might be reasonably viable but which lack the necessary capital to post a large security amount.

Additionally, because the security deposit is at risk, it will at some level be reflected in the price that developers bid into a given solicitation. The deposit provides collateral against those costs without requiring a complicated, potentially time consuming and costly study of actual damages. A deposit subject to forfeiture also provides a small additional incentive for the developer to complete the project within the allotted timeframe. Further, a reasonable deposit will help filter out projects that investors believe have no chance of success.

In SCE's RSC program we note that they have implemented a tiered development security deposit that varies based on the size of the project. We believe this approach has merit as it affords a way to balance the benefit of limiting projects to those that are likely to be the most viable with the risk of unnecessarily limiting the field of developers able to participate in the program. As an initial approach for the initial 1000 MW authorization, we believe it is appropriate to look to the precedent established in the context of existing Commission vetted programs targeting similar resources. In the context of SCE's Solar Photovoltaic Program, we adopted a security deposit of $20/kW. This program targets facilities primarily in the 1-2 MW size range. In the PG&E's Solar PV Program, we adopted a security deposit of $20/kW for projects less than 10 MW and $35/kW for projects 10 MW or greater. In contrast, for annual RPS solicitations, security deposits range from $30/kW to $50/kW for intermittent resources and $60/kW to $100/kW for baseload resources. In addition, in SCE's filing of its 2010 Annual RPS Procurement Plan, it has requested to increase its deposits from $30/kW to $60/kW for intermittent resources and from $60/kW to $90/kW for baseload resources. Furthermore SCE used these higher deposits in its RSC solicitation. Based on this information, we find it reasonable to require a $20/kW development security deposit for projects 5 MW and smaller, and a $60/$90 per kW deposit for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size. Should Energy Division find that these requirements undermine the goal of promoting a sufficiently competitive market, or that they are not serving their intended purpose, they may adjust these requirements via the resolution process.

9.2.3. Performance Deposit

The current FIT does not require a deposit to assure performance.[98] However, ED proposes no performance assurance/delivery term security deposit (herein called performance deposit) for projects between 1.5 MW and 5 MW.[99] ED proposes a performance deposit of 5% of expected total project

[98] A deposit is not required, but performance must be consistent with good utility (or prudent electrical) practices, the project must secure liability insurance, and poor project performance may result in the project owner paying damages to the IOU based on direct, actual losses. See, for example, PG&E § 399.20 PPA at Sections 4.6, 6.0 and 8.0. Also see SCE Renewable and Alternative Power Agreement and SDG&E Renewable Power Agreement at Sections 5.4, 8.0 and 9.0.

[99] In this case, the project's development deposit is refunded, and is not applied to the performance deposit.

revenue for projects greater than 5 MW.[100] Parties present a range of views from no performance deposit for any project to all projects paying a performance deposit.

We adopt a performance deposit for all projects electing subscription under the RAM. We do this because, as PG&E and others convincingly argue, the deposit is a form of collateral that helps compensate the IOU and ratepayers for damages from performance failure, particularly if the project ceases operation and has few or no remaining assets.[101] We also note the desirability of a performance deposit as explained by SCE:

> "SCE's experience, however, is that developers continuously reevaluate the financial performance of their project as their operating and maintenance costs, the energy prices available elsewhere in the market, and their tax incentives change over the life of the contract. Determinations are made whether continued performance under a contract is warranted versus other alternatives that may be available to maximize the developer's return on investment. Developers have in the past and continue today to seek ways to terminate their obligations under existing contracts because they believe a better deal may exist. Performance assurance [deposit] is designed to mitigate the consequences of SCE having to replace the failed project with a similar project."[102]

For projects less than 5 MW, we adopt a performance deposit equal to the development deposit ($20/kW, or less than 1% of the capital cost of the least

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[100] The $20/kW development deposit is applied to the performance deposit.

[101] Those damages might include the cost of replacement power, for example.

[102] T&C Reply Comments at 6-7.

expensive project).[103] That is, the development deposit converts to a performance deposit.

For projects 5 MW and larger, we adopt a performance deposit of 5% of expected total project revenues. We adopt this deposit for projects 5 MW and larger based on ED's recommendation, also noting that SCE requires a similar performance deposit for projects 5 MW and larger as part of its RSC program. We think SCE has reached the right balance between the burden of a larger performance deposit and project size.[104]

We are not persuaded by Sustainable Conservation, IEP and others who assert without evidence that a performance deposit makes it unreasonably difficult to obtain financing. IEP claims, for example, that an obligation of 5% of expected total revenues for a 20-year contract means a performance deposit equal to one year of revenues, which IEP says "can be prohibitively expensive."[105] Even if it "can be" for some, we have no evidence that it is prohibitively expensive for all. Projects of 5 MW and larger must obtain financing of several million dollars. There is no evidence that the incremental difficulty of obtaining

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[103] The least expensive project is about $2,000/kW. (See Chapter above on Pricing Approach.)

[104] It is informative to compare this to the performance deposit in the current RPS annual solicitation. Current PG&E annual solicitation protocols for any size project require a deposit of 5% of average expected project revenue (expressed as six months revenue for a 10-year contract, nine months revenue for a 15-year contract and one year revenue for a 20-year contract). (See PG&E Protocol June 29, 2009 at 23.) SCE requires a deposit for any size project of 5% of the notional value of the total energy payments expected during the term of the agreement, but not less than $1,000,000. (SCE Procurement Plan, July 17, 2009, Appendix E at 31.) SDG&E requires a delivery term security for any size project of $15/MWh times twice the annual estimated energy amount. (SDG&E Procurement Plan, June 22, 2009, Appendix A at 25.)

[105] T&C Comments at 9.

financing to also cover the performance deposit is unreasonable or fatal.[106] On the other hand, a relatively small performance deposit will help filter out projects that investors believe have no chance of success, provide incremental incentive (in addition to pay-for-performance pricing) for successful performance, and set aside a modest sum relative to possible damages.

A performance deposit becomes a cost of doing business. It does not give any project a particular advantage or disadvantage because it is uniform for all projects of the same size. A rational bidder will include this cost, along with all other costs, in its bid. A winning bid will, therefore, include this cost, which will in turn be paid by ratepayers. A performance deposit provides some ratepayer security (insurance) against poor performance or project failure, and is a reasonable price for ratepayers to pay over the life of the contract (via winning bid prices) for modest protection.

Solar Alliance and Vote Solar propose, without supporting evidence, that the performance deposit be limited to the lesser of six months or 5% of expected contract revenue.[107] We believe ED's proposal strikes the appropriate balance, and Solar Alliance and Vote Solar do not convincingly demonstrate why it should be modified.

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[106] Assume the investment cost for a five MW project is $3,000/kW, making the investment cost $15 million. If the project capacity factor is 33% and the FIT rate is $0.10/kWh, the total revenue over 20 years for a 20-year contract is $28.9 million. A performance deposit of 5% requires a deposit of $1.45 million. We are not persuaded that financing $16.45 million rather than $15 million is so difficult as to justify a different or no performance deposit. On the other hand, a deposit of $1.45 million reasonably provides additional incentive for good performance and collateral against potential damages caused by project non-performance or failure.

[107] T&C Comments at 9.

9.2.4. Performance Obligation

The Existing FIT requires (a) performance consistent with good utility (or prudent electrical) practices, (b) liability insurance against IOU losses, and (c) project liability for damages based on an IOU's direct, actual losses. ED proposes keeping these requirements and adding an explicit minimum performance threshold. Specifically, ED proposes a performance obligation of 140% of expected annual net energy production based on two years of rolling production, subject to payment of damages for failure to meet the performance obligation.[108] In addition, ED proposes that IOUs bear the risk of scheduling deviations if the generator (a) participates in the CAISO Participating Intermittent Resource Program (PIRP), (b) provides the IOU, as scheduling coordinator, with timely information on availability or (c) provides the IOU with remote access to metered output. In conjunction with 10- to 20-year contracts, the performance obligation facilitates IOU long-term renewable resource planning, according to ED.[109]

9.2.4.1. Party Comments

Comments range from support to opposition. IOUs generally support ED's proposal. PG&E proposes additional conditions to prevent sellers from underestimating output. For example, PG&E recommends an IOU pay the project the lower of spot price or 75% of contract price for output in excess of 120% of forecast net production. This facilitates IOU scheduling and planning, according to PG&E, by not letting the seller under-forecast output to avoid the risk of paying damages. PG&E also recommends specificity regarding "timely

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[108] That is, each year the project must deliver about 70% of its forecast annual net energy production.

[109] March 2009 Proposal at 11.

information" of project schedules to improve an IOU's ability to remarket excess RAM electricity.[110] SCE proposes use of predetermined capacity factors by technology.[111] Sustainable Conservation and other parties oppose ED's proposal on the basis that it is too onerous and makes financing more difficult.

9.2.4.2. Discussion

It is appropriate to require performance consistent with good utility (or prudent electrical) practices, liability insurance against IOU losses, and payment of damages based on an IOU's direct, actual losses. In addition we agree with Energy Division that it is prudent to adopt a minimum performance requirement. To that end, we adopt Energy Division's proposal of 140% of expected two-year production as a simple and straightforward approach. This obligation is identical to SCE's performance obligation in its RPS Pro Forma contract.

9.2.5. Damages for Failure to Perform

The Existing FIT limits damages to actual, direct damages, but does not state a maximum dollar amount. In no event under the Existing FIT is either party liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, regardless of cause.

ED proposes the RAM have a damage limit, wherein damages are capped at a level equal to the contract price minus average market price for the term year, but no greater than $0.05/kWh and no less than $0.02/kWh. In support, ED says a damage calculation is needed to enforce a performance obligation, but

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[110] PG&E Terms and Conditions Comments at 11-13.

[111] SCE Terms and Conditions Reply Comments at 7-8.

should be capped to ensure the contract may be financed and provide certainty to investors.[112]

9.2.5.1. Party Positions

Parties present a range of views. PG&E and SCE support ED's proposal. SDG&E says the $0.05 to $0.02 range is arbitrary and damages should be uncapped. Sustainable Conservation, Redwood Renewables, and others state that ED's proposed damages are excessive, even if limited, and should be reduced or eliminated. IEP asserts that a project should not be penalized for failure to perform by a minimum $0.02/kWh penalty (e.g., if the market price is lower than the contract price).

9.2.5.2. Discussion

We adopt the provisions of the Existing FIT for the RAM standard contract and decline to adopt ED's proposed damage limit.

We have no data to specifically relate the risk and cost to ratepayers of capped damages compared to the benefits, if any, from an increased ability to finance a project or provide certainty to investors. We have no specific data to assess the merits of the recommended range (i.e., $0.05/kWh and $0.02/kWh) versus another range. We also agree with IEP that it is unreasonable to set a minimum penalty even when actual damages are less. In the absence of information justifying a change, we think the best approach is to limit damages to actual amounts as we do now.

9.2.6. Force Majeure and Events of Default

PG&E's Existing FIT defines force majeure, and states that during a force majeure event PG&E (a) need not pay for energy or capacity and (b) may require

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112 March 2009 Proposal at 11-12.

the seller to curtail, interrupt or reduce deliveries. The Existing FIT contracts for SCE and SDG&E do not define force majeure and do not contain provisions similar to those of PG&E. All three Existing FITs contain various terms related to other events of default, such as failure by the seller to take corrective action after notice and seller's abandonment of facility and no party objects to them.

ED proposes that terms for force majeure and events of default be included in the RAM contract since these terms protect both buyer and seller from events outside their control.[113] Parties generally support ED's proposal, and thus provide limited comments.

We agree with Solar Alliance and Vote Solar that force majeure must be defined, and, to the extent there is liability, provisions must protect both buyer and seller, not just the IOU.[114] Terms for force majeure and events of default should be part of RAM. Consequently, IOUs should specify force majeure provisions and events of default in their RAM standard contracts.

9.2.7. Insurance

Insurance provisions in the Existing FIT contracts vary. PG&E's FIT includes a general liability insurance requirement of no less than $1 million for facilities between 0.1 MW and 1.5 MW (with reduced limits for smaller facilities), along with necessary requirements and conditions (for example, insurance is primary and not excess to insurance maintained by PG&E). SCE's and SDG&E's Existing FITs require general liability insurance of not less than $2 million for facilities between 0.1 MW and 1.5 MW (with reduced amounts for smaller facilities), along with necessary requirements and conditions. ED proposes that existing terms continue.

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[113] March 2009 Proposal at 12.

[114] Solar Alliance and Vote Solar Terms and Conditions Comments at 9.

9.2.7.1. Party Positions

Comments on insurance requirements vary. IOUs recommend higher insurance amounts for larger projects. SCE states it is revising insurance requirements under its Existing FIT, but provides no specifics. FuelCell Energy and others agree with ED that existing insurance requirements are reasonable.[115] Solar Alliance and Vote Solar state that insurance requirements should be consistent across the three IOUs, and recommend adoption of the levels used by PG&E.[116]

Environmental Council asserts insurance requirements are overly burdensome, and that there is limited need for insurance because of existing CAISO requirements. It also says the threat of losing queue position and forfeiting deposits limits the need for insurance.[117]

9.2.7.2. Discussion

We are not convinced by Environmental Council's claims that insurance requirements are overly burdensome. Environmental Council presents no credible data showing that the level of insurance premium for a $2 million policy is an overly burdensome percentage of either investment or operating cost. Nor does it show that the threat of losing queue position and deposits adequately changes behavior to offset or eliminate the risk of insured loss, or that the level of deposits adequately addresses potential losses covered by general liability insurance.

Insurance is a reasonable and time-tested method to address risk and potential loss and we expect the IOUs to require insurance in their RAM

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[115] FuelCell Energy Terms and Conditions Comments at 7.

[116] Solar Alliance and Vote Solar Terms and Conditions Comments at 9.

[117] Environmental Council Terms and Conditions Reply Comments at 9-10.

standard contracts. However, we allow the IOUs to determine the amounts and the terms and conditions of such insurance. Subject to Commission approval through a resolution, we expect them to take reasonable actions to protect their ratepayers while also promoting the competitive energy market. To this end, we encourage the IOUs to develop "tiered" insurance requirements, as appropriate, to address the circumstances of smaller projects or those using different technologies.

9.2.8. Scheduling Coordinator

PG&E's Existing FIT requires that PG&E be the seller's scheduling coordinator.[118] ED proposes that the IOU bear the risk of scheduling deviations if the generator provides the IOU, as scheduling coordinator, with timely information on its availability.[119]

We adopt a requirement for the RAM that the IOU be the scheduling coordinator for the project, and the IOU bear the risk of scheduling deviations if the generator provides the IOU, as the scheduling coordinator, with timely information on its availability. The IOU can decline scheduling coordinator responsibilities only upon a written, affirmative request from the seller that the IOU not be the scheduling coordinator, or if unable to perform scheduling coordinator duties (e.g., for a project out of its service area). This approach simplifies RAM administration and is reasonable.

10. Project Viability Requirements

ED proposes that RAM projects meet four minimum project viability criteria before being eligible to submit a bid, including site control, equipment

[118] PG&E § 399.20 PPA at 10.1 "Scheduling Obligations."

[119] March 2009 Proposal at 11.

standards, developer experience, and use of a commercialized technology. ED intends the project viability criteria to prevent the authorized capacity under RAM to be filled with non-viable projects to the detriment of projects that can come on line quickly. One of the primary goals of RAM is to support the development of small generation that can interconnect quickly to the distribution system, thereby avoiding the significant time and economic investment required for larger projects requiring transmission upgrades before they can be operational.

Parties present a range of views. Those in support argue the criteria will streamline review and facilitate program success. Those in opposition assert the criteria unreasonably increase project costs and risks.

We agree with ED that some level of minimum project viability criteria must be adopted to support success of the RAM program. We adopt the following minimum viability criteria here:

- Demonstration of site control upon submitting bid
- Demonstration of developer experience;
- Deployment of a commercialized technology;
- Filed interconnection application prior to bid submission;
- Ability for the project to be operational within 18 months of contract approval; and
- Tracking of project milestones.

These criteria should be incorporated in the IOUs' standard RAM contracts. As with all other elements of this program, the utilities may request modifications or additions to the viability criteria via the implementation advice letter process.

10.1. Site Control

ED recommends that the bidder must show 100% site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon award of the contract. We agree.

We want the RAM to be available for projects that are not unduly speculative. To do this, it is reasonable to require site control. Further, we recognize that site control on public lands may be manifested in something other than a lease or sale agreement. Consequently, we decline to adopt specific criteria for what constitutes demonstration of site control and rely upon the IOU to develop its own criteria.

10.2. Development Experience

ED recommends that the bidder demonstrate that the company and/or development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project. We agree.

Some parties object, saying this criterion is too subjective and exclusionary. They assert that the pay-for-performance nature of the program ensures that only viable projects will participate.[120]

We agree that pay-for-performance is a powerful tool that facilitates viable project self-selection. It is not enough for the RAM program, however. We seek a streamlined process that promotes ease of bid review and selection of projects which can become operational or be removed to open the queue for another project. Development experience complements pay-for-performance in

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[120] Pay-for-performance refers to the payment mechanism wherein projects are paid upon delivery of the product (i.e., electricity), with no payment when there is a failure to perform.

promoting that objective. We require that at least one member of the development team has either begun or completed construction of at least one project similar to the one proposed in the RAM program.

10.3. Commercialized Technology

ED proposes that RAM be limited to commercialized technologies to facilitate the 18-month on-line requirement for RAM generators. ED recommends commercialized technology be defined as one currently in use at a minimum of two operating facilities of similar capacity worldwide.

We agree with a commercialized technology screen. Research, demonstration and development of new technologies are vital, and we encourage such activities. However, research, demonstration and development should be funded in ways other than through the RAM program.

The RPS program itself is largely intended for commercial technologies. California seeks 20% RPS by 2010 with reasonably proven technologies that will provide safe and reliable electricity at just and reasonable rates. Experimental technologies may seek a place in the RPS resource mix in other ways and apply via other approaches (e.g., bilateral negotiations).

10.4. Interconnection

We recognize that the interconnection process is integral to the success of RAM. We note that issues regarding jurisdiction of distribution-level interconnections have been raised in FERC Docket No. ER11-1830-000. Commission staff will consider and address these issues in the future as appropriate and necessary, including, without limitation, ensuring non-discriminatory interconnection procedures based on developments in or resolution of the FERC proceeding.

Furthermore, we strongly encourage the IOUs to proactively modify their interconnection protocols for use in RAM where such modifications are reasonable and would enhance the implementation timelines and probability of success of RAM projects. Among other things, the IOUs should consider adopting or modifying criteria for expedited processing where possible, either at the FERC or at this Commission.

Since the interconnection process is a critical milestone to a project becoming operational, Recurrent recommends that bidders demonstrate they have filed their interconnection application by the time they bid into the RAM.[121] We agree.

Given the 18-month deadline for commercial operation, projects must have begun the interconnection application process by the time of bid submission. Thus, such a requirement is a reasonable screening criterion for bids. IOUs should require bidders to show with bid submission that the interconnection application has been filed.

11. Market Elements

11.1. Preferred Locations to Facilitate Interconnections

ED proposes that IOUs make information available on preferred distribution substations based on the available capacity of that substation, updated on a real-time basis.[122] This will significantly assist projects to locate in preferred locations, according to ED, thereby avoiding potential distribution and transmission upgrade costs and delays.

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[121] Recurrent Pricing Reply Comments at 10.

[122] August 2009 Pricing Proposal at 9.

11.1.1. Party Positions

Parties generally agree with the need for and desirability of this data, but present a range of views on feasibility and cost.

SCE proposes providing potential project areas (in the form of a zip code and geographic area bounded by landmarks or specific streets), along with an estimate of approximate available distribution capacity. SCE states that it will update this information as often as possible (including prior to each auction). SCE says this is the same as its solar PV Program auction proposal.[123]

PG&E believes a real time update may require significant investment in communication platforms and resources for system maintenance while not providing significant benefits, particularly if the auction is held only once per year. PG&E recommends a working group to study the issue.[124] SDG&E says it is not practical to determine preferred substations and update this list in real-time.[125]

SFUI says IOUs should provide this data on a real time basis, arguing that many cities and water authorities have their water and sewer distribution maps on the internet for immediate access by construction professionals. FIT Coalition states that Ontario Power Authority maintains two reports with needed FIT interconnection data, updated weekly. FIT Coalition recommends the Commission require each IOU to prepare and maintain an interconnection data report following a specified format, updated in real-time. More specifically, FIT Coalition requests the IOUs to provide the total capacity, allocated capacity,

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123 Advice letter 2364-E (process and criteria for evaluating IPP PV offers) resulting from D.09-06-49 (approving SCE's solar photovoltaic program). See SCE Pricing Comments at 7-8.

124 PG&E Pricing Comments at 12.

125 SDG&E Pricing Comments at 7.

queued capacity, and "available capacity" for all distribution substations and each circuit connected to a distribution substation.[126] Recurrent supports ED's proposal with updates as often as auctions occur (not real-time) with information at the zip code level (but not in more detail to avoid a land rush by developers).[127]

11.1.2. Discussion

No party argues that substation data is undesirable, or that it is unnecessary for making informed interconnection decisions. The real issues are the type and amount of data, and frequency of updates.

We recognize that it may be infeasible for an IOU to provide information on all substations during the initial rollout of this program given the large service areas of each IOU. Therefore, an IOU may initially focus on what it determines are "preferred" areas. Preferred areas are likely to be those near load where the IOU has a reasonable expectation of surplus transmission and/or distribution capacity.

The data must be sufficiently detailed to be useful. We agree with parties who assert SCE's proposed "project areas" (zip code and area bounded by landmarks or streets) fails to provide sufficient detail. To be most useful to potential projects, IOUs must provide data at the substation or circuit level. IOUs must have this information in order to execute their responsibilities for daily operations, system scheduling, and infrastructure planning to meet current and future demand. For the initial rollout, we adopt the FIT Coalition's recommendation to require the IOUs to provide the "available capacity" at the substation and circuit level, which we define as the total capacity minus the

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[126] FITC Pricing Comments at 8-9.

[127] Recurrent Pricing Comments at 9.

allocated and queued capacity.[128] The IOUs should provide this information in map format. If unable to initially provide this level of detail, each IOU must provide the data at the most detailed level feasible, and work to increase the precision of the information over time.

We do not require real-time provision of, and updates to, this information. Rather, we require updates at least once a month. We believe this strikes a reasonable balance between providing timely information to the market and not creating a requirement that is overly burdensome. We require that the information be provided as soon as possible, but no later than 60 days after the effective date of this decision. We also expect each IOU to pursue all cost-effective improvements to provide this data at a more detailed level with more timely updates. In order to facilitate data improvements, each IOU should examine DG interconnection screening tools currently used to screen DG interconnection applications. The IOUs should evaluate how individual project studies could be automated to provide the requested data and a reasonable assessment of a DG project's impact on the distribution system. As renewable DG penetrations continue to increase, new software tools and analytics should be evaluated, benchmarked, and used to keep pace with the expected increasing interconnection requests for incremental small DG units throughout the system.

We anticipate that each IOU will, over time, provide system-wide information. To not do so requires IOUs to continuously determine what are and are not "preferred" areas. That involves judgment better left to stakeholders. IOUs should eventually provide reasonable data on all areas, and let developers,

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[128] Allocated capacity refers to generators already connected to that substation or circuit. Queued capacity refers to generators in the interconnection queue at that substation or circuit.

along with IOUs and other stakeholders, decide if it makes sense to interconnect at various locations.

We recently adopted similar requirements with respect to SCE, PG&E, and SDG&E PV programs.[129] We therefore expect each IOU to make reasonable initial disclosures, and implement improvements over time. That same approach is reasonable for the RAM. Moreover, we expect the IOUs to simultaneously incorporate data and improvements with respect to their PV programs into the RAM program, and vice versa. Finally, we expect the IOUs to review other utility maps that perform a similar function and to work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums to order improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources.

11.1.3. Response to Critical Infrastructure Argument

SCE States:

> Finally, to the extent the Commission seeks detailed information concerning SCE's substations and distribution system infrastructure, the Commission should keep in mind that such information is protected by the Critical Infrastructure Information Act of 2002, 18 U.S.C § 388.113. Under that statute, detailed information concerning SCE's distribution system, such as precise substation location, substation design, circuit design capacity, voltage, and load information is Critical Energy Infrastructure Information ("CEII") and must be protected. SCE believes that information for distribution system voltage levels of 115 kV and 66 kV may include CEII and cannot therefore be released publicly.[130]

[129] D.09-06-049 at 40. Resolution E-4299 at 5-7. D.10-04-052 at Ordering Paragraphs 9 and 10. D.10-09-016 Ordering Paragraph 4.

[130] SCE Comments on Proposed Decision at 18-20.

The Critical Infrastructure Information Act of 2002 (CII Act) has no bearing on the Commission's decision about whether this information should be provided to potential distributed generation developers. The CII Act distinguishes between submitters and recipients of critical infrastructure information, with the result that the federal statute's prohibition on disclosure of protected confidential infrastructure information applies only when it has been "provided to a State or local government or government agency …" (6 U.S.C. § 133(a)(1)(E),) *See* County of Santa Clara v. Superior Court, 170 Cal. App. 4th 1301, 1319 (Cal. App. 6th Dist. 2009). In this instance, the information in question was generated solely by SCE. Because SCE is neither a state or local government agency, nor a recipient of critical infrastructure information from the federal government, the CII Act and accompanying regulations do not apply.

11.2. Qualified Facility Certification

ED notes that for SCE and SDG&E, the Existing FIT contains a requirement that the project be certified at FERC as a QF. ED proposes that there be no such requirement for the RAM.

We agree. The RPS program is not a QF program. (§ 399.15(e).) RAM is not a QF program. We decline to impose a QF requirement on RAM.

This does not prevent a project from certifying as a QF. A project may certify as a QF if it wants, but it need not do so to be eligible for RAM.

11.3. Conveyance of RECs

The Existing FIT provides that RECs are transferred to the IOU in relationship to the amount of the purchase. For full buy/sell under the Existing FIT, the IOU buys RECs coincident with the entire generation output. For excess sales, the seller retains RECs for the electricity it uses itself, and the IOU acquires

RECs coincident with the excess energy it purchases. (See D.07-07-027 at 33-35.) ED proposes no change relative to the transfer of RECs. We agree.

The same logic used in our Existing FIT decision (D.07-07-027) to justify transfer of RECs coincident with the purchased energy (either total energy production or excess only) applies to the RAM program. Thus, there is no reason to treat the RAM program differently.

We also decline to complicate these transactions by separating the renewable energy credit (REC) from the energy at this time. A guiding principle in RAM is simplicity, and allowing the separation of RECs from energy adds an additional layer of complication. We may consider separating the REC from the energy in the future, but do not do so here.

12. Regulation and Commission Oversight

12.1. RAM Program Modifications and Reports

As we have said elsewhere in this order, we adopt necessary design elements and details for the initial rollout of the RAM. We expect ED and parties to continually monitor the RAM, and recommend modifications based on evidence, if and as necessary. ED may act on its own motion to revise any aspect of the RAM program through resolutions proposed for Commission approval. Respondents and parties may seek modification by request to the Executive Director pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure. Any modifications proposed should be based on evidence that the modification is necessary to improve the RAM program.

Regular reports on the RAM program are also necessary and we require each IOU to provide an annual report on the RAM. The IOUs may combine RAM reports with other reports, such as the annual compliance filings required in the IOU Solar PV Programs. In addition, the IOUs will work with ED to determine the content of the RAM report before filing. Among other things, the RAM report shall address the competitiveness of the auctions; auction timing and design issues; and project status, including the time and the cost necessary to interconnect and bring projects on-line.

Since the purpose of RAM is the procurement of projects that can come online quickly, in order to ensure that the procurement protocols and program design result in that outcome, we require the IOUs to report on the project development milestones. The IOUs must work with Commission staff to develop a simple methodology to measure the status of project development and include this in their implementation advice letter.

The report must also include any other relevant information, data, and analysis to present a complete report to the Commission. IOUs must work with ED to design a report template that includes these elements.

12.1.1. Public Release of Aggregated Bid Data

We have rules regarding confidentiality of electric procurement data. (See D.06-06-006 as modified by D.07-05-032.) Those rules presume "that information should be publicly disclosed and that any party seeking confidentiality bears a strong burden of proof." (*Id*. at 2.) Due to strong public interest in RPS, we require greater public access to RPS data than other data. (*Id*. at 3.) We reaffirm the importance of greater public access to RPS data here. We emphasize, for the reasons explained below, that this is particularly true for the RAM program.

ED proposes that it release RAM data on an aggregated basis to the extent consistent with our rules. ED says individual bid prices will remain confidential.[131]

[131] August 2009 Proposal at 10.

Parties present a range of views. FIT Coalition argues that winning prices for each project must be revealed or the key aspect of RAM identified by ED (i.e., that RAM provides a long-term investment signal) will not be fulfilled.[132] Vote Solar, TURN and others recommend maximum disclosure of pricing bids.[133] Absent complete transparency, Solar Alliance proposes an after-the-fact review by a designated PRG.[134] PG&E points out that limited aggregate information (i.e., number of projects, megawatts per resource type) may be disclosed, but information on offers received in a solicitation may not be made public for three years.[135]

Information is vital to an effectively functioning competitive market. We expect IOUs and ED to make the maximum amount of information public. In fact, all data must be public unless a party carries a strong burden of proof otherwise. It is particularly important for the RAM due to our reliance on the underlying market being competitive.

It is also important that the maximum amount of price information be available in order to gain public acceptance of the RAM. The majority of parties recommending a fixed price FIT, for example, do so because they assert it is open, transparent and objective, while RAM, absent adequate price and other information, is closed, opaque and subjective. The goal of RAM may be lower prices (compared to a fixed price FIT), but without price data, and market information on the degree of competition, the public must take on faith any statement (including those made by an IOU or the Commission) that costs have

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132 Pricing Comments at 5.

133 Vote Solar Pricing Comments at 10; TURN Pricing Reply Comments at 9.

134 Pricing Comments at 18.

135 Pricing Comments at 13-14.

been reduced or competition achieved. RAM program credibility requires that IOU and Commission administration provide full opportunity for the public to assess the merits of the RAM and reach its own conclusions.

We expect ED, respondents, and parties to explore all reasonable means to make price and other information widely available. At a minimum, we require specific information to be revealed publicly. For all bids received and shortlisted, we require the IOUs to provide the following information: names of participating companies and the number of bids per company; number of bids received and shortlisted; project size, participating technologies, quantitative summary of how many projects passed each project viability screen, and location of bids by county provided in a map format. Finally, the IOUs must release information on the achievement of project development milestones for all executed RAM contracts. Pursuant to the program goal to select projects that can come online quickly, we believe this information is essential to verify that the program protocols and design are achieving the intended outcome. This transparency will allow the Commission to make changes to the program in order to increase its efficiency and effectiveness.

12.2. Cost Recovery

AReM proposes that costs related to the RAM should be borne by bundled service customers, and not customers of ESPs or CCAs. IOUs, TURN and others believe all customers should bear the costs of the RAM, including customers of ESPs and CCAs.

We currently permit an IOU to recover costs incurred in meeting its RPS obligations (including Existing FIT costs) from its bundled customers. These are typically part of generation or procurement costs recovered via each utility's annual Energy Resource Recovery Account proceeding. We also permit recovery of appropriate non-bypassable costs (including stranded costs associated with RPS resources) from certain customers that depart from the utility bundle after those new resources are procured.[136] We are not persuaded to make any change for the RAM. We recently reached the same conclusion regarding a similar program,[137] and know of no reason to reach a different result here.

13. RAM Program Implementation

13.1. RAM Implementation Advice Letter Filing

PG&E, SCE, and SDG&E shall file Tier 3 advice letters within 60 days of the date this order is mailed to put RAM procedures in place. The implementation advice letters shall include procurement protocols, a RAM standard contract consistent with the provisions of this decision, and any other details necessary to implement the program. Furthermore, the IOUs should use the advice letters filed pursuant to the decisions establishing the IOU Solar Photovoltaic Programs[138] as a model on what to include in the RAM advice letter.

Other requirements of the advice letter filing including the following: the IOUs shall state when they will hold a RAM auction and specify the amount of capacity and the products they will plan to procure in each auction over the next two years. IOUs shall include and explain any other bid selection criteria they will utilize, for example a seller concentration limit. The advice letter filing shall include a description of the generation profiles and characteristics that correspond with each product bucket. Furthermore, the IOUs shall provide the preferred locations map and a description of how the maps were computed. The

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[136] Those are departing direct access customers, CCA customers, new Western Area Power Administration and split wheeling departing load customers, and departing load associated with a large municipalization. (D.08-09-012, Ordering Paragraphs 1 and 3.)

[137] D.10-04-052 at 69.

[138] See D.09-06-049, D.10-04-052, and D.10-09-016.

IOUs may include any other requests related to the implementation of RAM auctions, which are consistent with this decision, for Commission consideration. Parties may file and serve comments or protests within 20 days of the date the IOUs' implementation advice letters are filed. (General Order 96-B)

Lastly, in the interest of ensuring that this program remains relevant and effective we believe that periodic program forums are appropriate and should be held once per year, beginning after the initial RAM auctions are conducted. These forums will provide a venue to discuss program design and implementation, and provide opportunities for stakeholder comments and feedback. Such forums can provide invaluable insights into the effectiveness of the program as adopted and suggest potential modifications that may be appropriate to ensure the program is realizing its intended aims. The IOUs may use the stakeholder feedback from each forum to develop and submit advice letters seeking modifications to the RAM program. Similarly, Energy Division may issue a resolution on its own motion to propose program modifications based on information from these program forums, as well as information from the program reports described above.

13.1.1. The Existing FIT

The Existing FIT—the statutory MPR-based fixed price tariff for 250 MW of water/wastewater retail customers—applies to projects independently of the RAM. We will update the Existing FIT in a separate decision to address final implementation issues scoped in June 2008, along with provisions of SB 32. This will include, for example, treatment of excess sales to program capacity limits, third party ownership, an updated price, an updated MW allocation (from 250 MW for water/wastewater customers of electrical corporations to 750 MW for all customers of electrical corporations and local publicly owned electric utilities), and other items as appropriate.

14. Comments on Proposed Decision

On August 24, 2010, the proposed decision of Administrative Law Judge (ALJ) Burton W. Mattson in this matter was mailed to 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 September 27, 2010, comments were filed by Axio, CalSEIA, CARE, CEERT, DRA, enXco, FIT Coalition, Fuel Cell Energy, GPI, IEP, Jan Reid, LS Power Associates, PG&E, Recurrent Energy, SCE, SDG&E, SFUI, Sierra Club, Solar Alliance, Sustainable Conservation, TURN, and Vote Solar. On October 4, 2010, reply comments were filed on by CARE, DRA, FCE, FIT, GPI, Jan Reid, LS Power Associates, PG&E, SCE, SDG&E, SFUI, Solar Alliance, Sustainable Conservation, TURN, Vote Solar, Walmart, and Western Power Trading Group. The proposed decision was significantly modified to address the comments. Among other things: the value of RAM as a program to target viable renewable distributed generation that can interconnect quickly was clarified; the simplified preapproval threshold was eliminated; our intent to explore a more nuanced need for RAM by coordinating with the CPUC's procurement planning process was clarified; the discretion to reject bids that are not cost competitive or resulted in market manipulation was given to the IOUs; the requirements of some of contract terms and conditions were left to the discretion of the IOUs; the development deposit requirement was increased; the termination contract requirement was removed; the project size limit was changed to 20 MW; only the excess sales from a generator will count toward the 1,000 MW capacity limit; RAM documents need not be uniform across IOUs; the IOUs must provide more relevant preferred location information to bidders; the eligible location for RAM projects was limited to the IOU service territories; annual RAM reports shall be filed and the content determined in collaboration with Energy Division and IOUs; and a process is provided for timely modifications to the RAM program.

15. 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. It is feasible and desirable to design a streamlined procurement process for smaller renewable energy projects.

2. Smaller renewable energy projects may be able to be developed more quickly and with greater certainty than larger scale renewable projects given their smaller geographic and environmental footprint, and the ability to interconnect without requiring additional transmission or distribution system upgrades.

3. RAM is a market-based pricing mechanism wherein the price is set by the seller participating in a competitive solicitation, not the Commission.

4. A fundamental assumption underlying the adopted RAM is that competition is, and will remain, vigorous in this market, resulting in just and reasonable rates and optimal resource outcomes.

5. The RPS statute and program is premised upon employing competition to reach optimal outcomes.

6. The time and cost of an administrative process to set a fixed rate for a FIT tariff is not zero, and could be the same as or more than the sum of all RAM bid preparation costs.

7. A RAM-determined contract price provides reasonable price certainty for the purposes of project economic evaluation and subsequent cash-flow for cost recovery.

8. A RAM balances the ability for a small project to secure financing and attain a reasonable price, with the assurance that the ratepayer is not overpaying.

9. The Existing FIT is a must-take obligation on a first-come first-served basis up to a program capacity limit.

10. Because IOUs are given discretion to reject bids that are uncompetitive, the issue of whether RAM is a must-take obligation is moot.

11. SCE has implemented its RSC program, has conducted one solicitation in 2010, and has already executed 21 contracts pursuant to this solicitation.

12. Establishing one primary procurement vehicle for the system-side DG market can enhance competition and put downward pressure on bid prices.

13. A proportional allocation of the 1,000 MW cap to the largest of the four SMJUs would be about 4 MW, and to all four of the SMJUs would be about 6 MW.

14. Relative to a 20 MW per project criterion, allocating 4 MW or less to each of the four SMJUs makes little practical sense while increasing administrative burden.

15. Calculating a revenue requirement cap will require coordination with the CPUC's procurement planning processes.

16. Before a revenue requirement cap is calculated, a total capacity cap of 1,000 MW is a relatively simple approach that is sufficiently large to test the adopted program but sufficiently small to provide protection against adverse outcomes.

17. If an IOU would like to procure beyond its initial allocation of the 1,000 MW cap, it is reasonable for an IOU to request an increase in its implementation advice letter.

18. It is reasonable to authorize the Director of Energy Division to explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process to assess the need for RAM products going forward.

19. It is reasonable for the Director of Energy Division to have the authority to adjust the capacity cap on its own motion or in response to a utility advice letter filing requesting an update to the cap amount.

20. If IOUs hold two RAM auctions per year, it will provide market participants with regular opportunities to participate.

21. Multiple RAM auctions will not be unreasonably burdensome or costly if IOUs design a standard contract and bid protocol that meet the goals of being simple, easy to implement, and streamlined.

22. Project selection limited to the price variable is consistent with the RAM being relatively simple and transparent.

23. Ranking an auction result only by price is reasonable when the auction is targeting products with similar value.

24. Renewable products that are baseload, peaking as-available and non-peaking as-available provide different value to an IOU's electric portfolio.

25. It is reasonable for an IOU to have the discretion to reject bids if they are not cost competitive or if there is evidence of market manipulation.

26. A Tier 2 advice letter gives notice to the Commission and the public regarding a RAM contract without causing implementation delay.

27. Not requiring the seller to be a retail customer, and not requiring the project be located on property owned or under the control of the retail customer, provides a reasonable opportunity to increase the number of potential sellers, the amount of competition, and the amount of renewable generation.

28. Having both the full buy/sell and excess sales options available at the choice of the seller has been, and continues to be workable, with no evidence showing the contrary.

29. The CEC has repeatedly recommended that we study and implement an FIT for projects up to 20 MW, and a project size of 20 MW is used for many program and regulatory purposes.

30. Small RPS projects connecting to utility service territories incur none of the additional costs associated with some other forms of renewable generation.

31. Adopting standard non-negotiable RAM contracts is consistent with the goals of the RAM program, including simplicity and reduced transaction costs.

32. An 18-month limit for a project to begin commercial operation (with one potential six-month extension) reasonably streamlines RAM administration, while accommodating legitimate delays.

33. A development deposit is a form of collateral that helps compensate the IOU and ratepayers for damages from a project that fails to reach commercial operation.

34. A development deposit of $20/kW for projects 5 MW and smaller, and a $60/$90 per kW for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size is consistent with IOU requirements in other programs for similar resources.

35. A performance deposit is a form of collateral that helps compensate the IOU and ratepayers for damages from project performance failure.

36. A performance deposit is a cost of doing business, and a rational RAM bidder will include this cost with all other project costs in bid development.

37. It is appropriate to require performance consistent with good utility practices, and it is prudent to adopt a minimum performance requirement.

38. The risk and cost to ratepayers of capping damages at 5 cents/kWh compared to the benefit from an increased ability to finance contacts, if any, is unknown, while a minimum penalty of 2 cents/kWh penalizes projects if actual damages are less.

39. A requirement that the IOU be the project's scheduling coordinator (unless this service is specifically declined by the project, or the IOU is unable to perform this service) simplifies RAM administration.

40. A requirement that a project meet certain minimum project viability criteria to submit a bid provides an initial screen of more viable from less viable projects; simplifies bid review and selection; provides an incentive for bidders to submit realistic, competitive bids; complements the provision of limited time to commercial operation; assists with reasonable queue management; and should reduce the number of extension requests.

41. Issues regarding jurisdiction of distribution-level interconnections have been raised in FERC Docket No. ER11-1830-000.

42. Information is vital to an effectively functioning competitive market.

43. Data on the feasibility of interconnection must be sufficiently detailed and current to be useful to potential project developers.

44. Preferred areas are likely to be those near load where the IOU has a reasonable expectation of surplus transmission or distribution capacity.

45. As renewable DG penetrations continue to increase, IOUs should evaluate and benchmark new software tools and analytics to keep pace with the expected increase in interconnection requests for small DG.

46. The Critical Infrastructure Information Act of 2002 has no bearing on the Commission's decision about whether interconnection information should be provided to potential distributed generation developers.

47. It is reasonable to allow ED to revise any aspect of the RAM program through resolutions proposed for Commission approval.

48. IOU reporting on their experience with RAM will allow the Commission, IOUs, and market to evaluate the design of the program and track its progress.

49. IOUs recover RPS program costs from bundled customers, while certain non-bypassable costs are also recovered from customers that depart from the utility bundle after new resources are procured.

Conclusions of Law

1. A streamlined procurement process in the form of RAM should be implemented for smaller system-side renewable energy market.

2. A market-based pricing approach should be adopted for the RAM.

3. RAM avoids or eliminates a jurisdictional conflict with FERC's wholesale rate-setting authority.

4. The limitation imposed by Pub. Util. Code Section 399.15(d) on procurement of renewable energy at prices above the MPR does not apply to RAM.

5. The IOUs should be required to use RAM exclusively for the procurement of system-side renewable projects up to 20 MW in size with the exception of other Commission-approved programs such as the utility solar photovoltaic programs already authorized by the Commission and annual RPS solicitations;

IOUs should not use voluntary programs that target the same market segment or bilateral negotiations.

6. IOUs should limit their procurement of system-side renewable DG to the RAM, to annual RPS solicitations, and to Commission-approved utility solar photovoltaic programs.

7. RAM should apply only to the three largest IOUs.

8. SCE should be given the discretion to apply the contract capacity of any of the 21 contracts already executed through its 2010 RSC program to its RAM capacity cap if the contract(s) is approved by the Commission.

9. SCE should be given the discretion to submit additional contracts to the Commission for approval resulting from its 2010 RSC solicitation via a Tier 3 advice letter; however, the capacity associated with these contracts should not reduce SCE's procurement obligations under RAM.

10. The following RAM auction design elements should be adopted: an interim procurement requirement of 1,000 MW, subject to increase in an IOU's implementation advice letter or adjustment in any appropriate proceeding; an initial capacity allocation to the three IOUs using the same proportions as in the Existing FIT program; 25% of the 1,000 MW total allocation offered in each RAM auction; each IOU should hold two RAM auctions per year; project bid selection based only on price with least-cost bids selected first; and IOUs can choose the types of products to solicit, subject to Commission approval; simplified contract approval through Tier 2 for RAM contracts executed up to the capacity cap authorized by the Commission for each IOU.

11. The Director of Energy Division should be authorized to explore methodologies for aligning RAM procurement authority with the Commission's

procurement planning process to assess the need for RAM capacity and products in the future.

12. At any time, the Director of Energy Division may issue a resolution, either on its own motion or in response to a utility advice letter filing to update the capacity authorization.

13. An IOU should be authorized to request an increase to its capacity cap to be procured through the RAM if consistent with its portfolio need.

14. Respondents and parties may seek modification by request to the Executive Director pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure. Any modifications proposed should be based on evidence that the modification is necessary to improve the RAM program.

15. While the inputs and methodology are not in place to adopt a revenue requirement cap at this time, the Director of Energy Division may explore methodologies for aligning RAM procurement authority with the Commission's procurement planning process.

16. If an auction is less than fully subscribed, or if the subscribed capacity drops out of the program, the unsubscribed or dropped capacity should be added to the next available auction.

17. Each of the three largest IOUs should conduct two RAM auctions per year; the three IOUs should hold RAM auctions simultaneously.

18. RAM project selection should be by price with least expensive selected first.

19. Rates for RAM should be all-in energy rates adjusted by time of delivery (TOD) factors.

20. Eliminating negotiation over price, terms, and conditions as part of the RAM reasonably streamlines and simplifies this procurement option.

21. RAM products should be baseload, peaking as-available, and non-peak as-available electricity.

22. An IOU should define the products it would like to procure through RAM based on its portfolio need, and include this request in its implementation advice letter.

23. An IOU should be able to reject bids if it determines that one or more bids are not cost competitive or if there is evidence of market manipulation. If this occurs, the IOU should demonstrate in an advice letter filing to the Commission why bids were rejected before the capacity cap was exhausted.

24. An IOU should file all executed RAM contracts up to the capacity allocation approved by the Commission in response to its implementation advice letter through a Tier 2 advice letter filing.

25. A seller eligible for RAM should not be required to be a retail customer of the IOU, and an eligible project should not be required to be located on property owned or under the control of a retail customer.

26. Projects participating in RAM, either through a full buy/sell or excess sales transaction, should not exceed 20 MW.

27. Sellers selected via RAM should continue to have the choice of full buy/sell or excess sales.

28. Deliveries should be from projects located in one of the IOU's service territories.

29. Eliminating negotiation over price, terms, and conditions as part of the RAM reasonably streamlines and simplifies this procurement option.

30. Each IOU should develop its own standard RAM contract and file it as part of its implementation advice letter filing; to the greatest extent possible,

IOUs should work from an existing, simple standard contract that has been vetted through a stakeholder process.

31. RAM projects should be given 18 months from contract execution to begin commercial operation or lose RAM eligibility, subject to one 6-month extension provided the seller can prove a regulatory delay.

32. A RAM development deposit of $20/kW for projects 5 MW and smaller, and a $60/$90 per kW for intermittent and baseload resources, respectively, for projects greater than 5 MW and up to 20 MW in size should be adopted, with this deposit either refundable upon achieving COD or applied to the subsequent performance deposit; it should be due on the date of contract execution in the form of cash or a letter of credit from a reputable U.S. bank; and it should be forfeited if the project fails to come on line within 18 months (or with one six-month extension if granted by the IOU).

33. For projects less than 5 MW, a RAM performance deposit should be adopted equal to the development deposit; for projects 5 MW and larger, a performance deposit should be adopted of 5% of expected total project revenues.

34. RAM product performance should be consistent with good utility (or prudent electrical) practices; damages should be limited to the actual, direct losses (without a maximum or minimum amount); and neither party should be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages regardless of cause.

35. RAM product performance should, in addition, require deliveries of 140% of expected annual net energy production based on two years of rolling production.

36. RAM standard contracts for the three IOUs should define and apply force majeure and events of default provisions.

37. The RAM should require that the IOU be the seller's scheduling coordinator (unless that service is affirmatively declined by the seller, or the IOU is unable to perform the service); and the IOU, as scheduling coordinator, should bear the risk of scheduling deviations if the generator provides the IOU with timely availability information.

38. A bidder should be required to show as part of its bid that the project meets minimum project viability criteria, with failure to meet these criteria justification for an IOU to reject the bid.

39. An IOU should use pre-determined project viability screens to determine which bids are eligible to participate in the auction. These screens include: demonstration of site control upon submitting bid; demonstration of developer experience; deployment of a commercialized technology; and filed interconnection application prior to bid submission.

40. The IOUs should track project milestones and provide this information publicly using a simple format developed in collaboration with Commission staff.

41. If an IOU would like to include other bid evaluation metrics, such as seller concentration, in a RAM auction, it should propose the criteria in its implementation advice letter for Commission review; an IOU's proposal should not conflict with a price-only bid selection methodology.

42. Commission staff will consider and address interconnection issues in the future as appropriate and necessary, including, without limitation, ensuring non-discriminatory interconnection procedures based on developments in or resolution of the relevant FERC proceeding.

43. The IOUs should proactively modify their interconnection protocols for use in RAM where such modifications are reasonable and would enhance the

implementation timelines and probability of success of RAM projects. The IOUs should consider adopting or modifying criteria for expedited processing where possible, either at the FERC or at this Commission.

44. IOUs should provide the "available capacity" at the substation and circuit level, updated on a monthly basis, which is defined as the total capacity minus the allocated and queued capacity. The IOUs should provide this information in map format.

45. Each IOU should examine DG interconnection screening tools currently used to screen DG interconnection applications. The IOUs should evaluate how individual project studies could be automated to provide the requested data and a reasonable assessment of a DG project's impact on the distribution system.

46. The IOUs should work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums in order to improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources.

47. RAM should not require an eligible project to be a QF.

48. RECs should be transferred to the IOU for the energy that is purchased by the IOU.

49. Regular reports on the RAM program are also necessary and each IOU should provide an annual report on RAM. The IOUs may combine RAM reports with other reports, such as the annual compliance filings required in the IOU Solar PV Programs.

50. IOUs should work with ED to determine the content of the RAM report before filing. Among other things, the RAM report should address the competitiveness of the auctions; auction timing and design issues; and project milestones and status, including the time and the cost necessary to interconnect

and bring projects on-line and any other information reasonably necessary to present a complete report and allow monitoring of important program elements.

51. The IOUs should hold annual program forums to solicit feedback from stakeholders regarding the RAM program design and implementation and potential modifications and refinements thereto.

52. IOUs and ED should make the maximum possible amount of RAM information public to, among other things, gain public acceptance of RAM.

53. RAM program costs should be charged to bundled customers and departing customers in the same manner as now charged.

54. Each IOU should, within 60 days of the date of this order, file a Tier 3 advice letter in compliance with the orders herein.

55. This order should be effective today to permit timely filing of the authorized RAM bid protocols and standard contracts, and timely conduct of the first RAM auction, thereby providing additional tools for IOUs to reach RPS targets and goals, and helping IOUs avoid the potential of penalties for failure to reach required RPS targets.

O R D E R

IT IS ORDERED that:

1. Within 60 days of the date this order is mailed, each electrical corporation named herein shall file and serve a Tier 3 advice letter containing a standard contract, bid protocol and any other necessary documents to implement the renewable auction mechanism adopted in this order.

    a. The electrical corporations are: Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

    b. The advice letter shall be in compliance with General Order 96-B.

c. The standard contract and bid protocol shall be consistent with the directions stated in this decision, and summarized in Appendix A. These directions include, but are not limited to:

- rate determination is by use of the renewable auction mechanism;
- capacity limit and procurement requirement of at least 1,000 megawatts, allocated to the three electrical corporations;
- no more, and no less, than 25% of the allocation offered in each auction;
- unsubscribed capacity (or subscribed capacity that drops out) is added to the next available auction;
- two auctions per year;
- electricity products eligible for purchase via this procurement protocol are baseload, peaking as-available, and non-peaking as-available;
- selection of winning bids is by price (least expensive selected first);
- bids are not negotiable with respect to bid price, terms or conditions;
- rates are paid on the basis of all-in energy rates by time of delivery;
- contracts executed pursuant to this program to be submitted via Tier 2 advice letter;
- projects 20 megawatts and less may participate;
- standard non-negotiable contract;
- bidders must show in the bid that the project complies with adopted project viability criteria;
- a project must be located in one of the investor-owned utility service territories;
- a seller eligible to subscribe under this procurement program need not be a retail customer of the electrical corporation, and the project need not be located on property owned or under the control of the retail customer;

- and a seller eligible to subscribe under this procurement program need not be a qualifying facility under federal law.

2. The IOUs shall use an Independent Evaluator (IE) consistent with and pursuant to the requirements established in Decision (D.) 07-12-052, as modified by D.08-11-008 to assess the integrity and competitiveness of each RAM auction as well as to assess the appropriateness/reasonableness of the bids selected from those auctions. The IE's report shall be submitted by the respective utility to the Commission along with the Tier 2 advice letter seeking approval of contracts resulting from each RAM auction.

3. Each electrical corporation named herein shall file and serve one Tier 2 advice letter with the Commission including all executed contracts resulting from each auction up to the approved capacity limits. After the effective date of this decision, the electrical corporations may not submit contracts with facilities up to 20 MW in size that are negotiated and executed outside of the Renewable Auction Mechanism program with the exception of contracts executed pursuant to the annual Renewables Portfolio Standard Program, the Commission-approved utility solar photovoltaic programs, and the contracts that Southern California Edison has or will execute pursuant to its 2010 Renewables Standard Contract program, or other Commission-approved programs. The electrical corporations are: Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

4. Each year, each electrical corporation named herein shall file data, information, and evaluation in a report on relevant aspects of the renewable auction mechanism adopted in this order, and summarized in Appendix A.

   a. The electrical corporations are: Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

b. The reports shall be published on the electrical corporation's website.

c. The electrical corporations shall adopt a uniform form and format in consultation with Energy Division.

d. Each report shall include information to monitor program design and elements. It shall include information, data, and evaluation with respect to: competition, competitiveness, and auction design. The first report shall include information and recommendations on a definition of competition generally, a definition of competition in this market specifically, and measures of competition.

e. As data becomes available, reports shall contain information described in this order including but not limited to: measures of market competition, measures of market power, seller concentration, data on each auction (based on all bidders), data on each auction (based on projects selected), and any other data necessary to present a complete report. At a minimum, we require specific information to be revealed publicly. For all bids received and shortlisted, we require the IOUs to provide the following information: names of participating companies and the number of bids per company; number of bids received and shortlisted; project size, participating technologies, quantitative summary of how many projects passed each project viability screen, and location of bids by county provided in a map format. Finally, the IOUs must release information on the achievement of project development milestones for all executed RAM contracts.

5. The IOUs shall hold a program forum once per year, beginning after the initial RAM auctions are conducted to discuss program design and implementation, and provide opportunities for stakeholder comments. In organizing these forums, the utilities should consult with Energy Division staff and at a minimum notify the service list to this proceeding or subsequent proceedings. The IOUs may use the stakeholder feedback from each forum to develop and submit an advice letter seeking

modifications to the RAM program. Similarly, Energy Division may issue a resolution on its own motion to propose program modifications based on information from these program forums or the annual reports developed pursuant to Ordering Paragraph 3 above. The IOUs may combine the RAM program forums with other program forums, such as those required for the IOU Solar PV programs.

This order is effective today.

Dated December 16, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

APPENDIX A

SUMMARY OF ADOPTED PROGRAM

The attached decision establishes a new procurement protocol called the Renewable Auction Mechanism, or RAM. The orders, while not limited to those stated in this abstract, are summarized below. The items are generally summarized in the same sequence discussed in the attached decision.

RENEWABLE AUCTION MECHANISM

1. **Price Determination**: Renewable Auction Mechanism (RAM)
    - Projects submit price bids
    - IOUs select projects in order of least-costly first, up to program capacity limit
2. **Auction Design**:
    a. Program Procurement Requirement:
        i. 1,000 MW Capacity Limit
        ii. Adjustment to the Program Capacity Limit: May occur in any appropriate proceeding or through a Tier 3 advice letter/Resolution, or a Resolution on the Commission's own motion
        iii. Capacity Allocation for total RAM program and per auction

UTILITY	TOTAL PROGRAM (MW)	PER AUCTION (MW)
SCE	498.4[139]	124.6
PG&E	420.9	105.2
SDG&E	80.7	20.2
TOTAL	1,000.0	250.0

[139] As described in the text of this decision, SCE's procurement obligation may be reduced by the capacity represented in the 21 contracts it has executed from its 2010 RSC solicitation. Furthermore, SCE may elect to submit additional contracts resulting from its 2010 RSC solicitation via a Tier 3 advice letter, however, these additional contracts and associated capacity will not reduce SCE's procurement obligations under RAM.

iv. **Number of Auctions per Year**: Two per year, held concurrently by all three IOUs; a project may bid into all three auctions.

v. **Amount per auction**: 25% of the total program allocation will be offered in the initial auction; unsubscribed capacity, or drop out capacity, is added to the next auction

vi. **Procurement Requirement**: Each IOU must enter into a standard contract with each winning bidder up to the capacity limits in each solicitation and total program capacity limits. IOUs select on the basis of least costly projects first until the IOU fully subscribes its allocated capacity for that auction. IOUs have the discretion to not enter into contracts if there is evidence of market manipulation or if the bids are not competitive compared to other renewable procurement opportunities. The IOU must submit an advice letter explaining its decision not to enter into contracts.

b. **Products and Selection**

- **Products**: Firm, non-firm peaking, and non-firm non-peaking electricity
    - o IOU shall specify the amount of each product for the initial four auctions in the first advice letter filed pursuant to this order. Utilities are required to solicit and procure capacity up to the capacity limit for each solicitation.
    - o Project must submit eligibility information (e.g., generation profile, project characteristic information) corresponding to the product bid, as established by the IOU
- **Selection**: Each product is selected on the basis of price, least expensive first until the capacity limit in each solicitation is reached; IOU may normalize (adjust) bids to place bids on an equivalent basis before making least cost selection using method approved, if any, in the advice letter implementing RAM
- **Independent Evaluator:** Utilities will employ an Independent Evaluator to assess the competitiveness and integrity of each RAM auction and submit the IE's report with it Tier 2 advice letter requesting approval of contracts resulting from those auctions.

3. **Eligibility:**

    - **Location**: Combined IOU service territories (e.g. a project bidding into SCE's auction can be located in either PG&E or SDG&E's service territory).
    - **Retail Customer/Third Party Ownership**: Seller need not be a retail customer and the facility need not be located on property owned or under the control of a retail customer
    - **Utility Applicability**: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E)
    - **Project and Transaction Limit**: 20 megawatts (MW)

      This is the maximum size for any project signing a full buy/sell or excess sales transaction through the RAM.[140]
    - **Full Buy/Sell or Excess Sales**: Seller may elect either full buy/sell or excess sales
    - **Counting Excess Sales**: Capacity associated with the transaction size is applied to the program cap.

4. **RAM Standard Contract:**

    - **Contract Language:** IOUs can use their individual contracts, but should start with a contract that is simple, streamlined, and has already been vetted by stakeholders through another CPUC program.
    - **Negotiations:** Price, terms, and conditions are not negotiable.
    - **Contract Terms and Conditions**
        - **Length of Time to COD**: Within 18 months of contract execution, with one 6-month extension for regulatory delays.
        - **Development Deposit**: $20/kW for projects 5 MW and smaller, and a $60/$90 per kW for intermittent and baseload resources,

[140] If a project elects to pursue excess sales, the total project size, including the capacity associated with the wholesale transaction under RAM as well as the capacity associated with onsite load, is counted as part of the project's capacity for purposes of project eligibility. However, only the capacity associated with the wholesale transaction will count against the capacity limit under RAM.

respectively, for projects greater than 5 MW and up to 20 MW in size, refundable upon achieving commercial operation or applied to the performance deposit; development deposit is due on the date of contract execution in the form of cash or letter of credit from a reputable U.S. bank; development deposit forfeited if project fails to come on line within 18 months or other 6-month extension granted by IOU.

- **Performance Deposit**:
  - For projects less than five MW: conversion of development deposit to performance deposit
  - For projects five MW and larger: 5% of expected total project revenues
- **Performance Obligation**:
  - Performance is required to be consistent with good utility (or prudent electrical) practices; project is obligated to have liability insurance against utility losses; the project is liable for an IOU's direct, actual losses; and project must perform consistent with generation profile or other characteristics for the product, to the extent stated in the Commission-adopted contract
  - Minimum deliveries of 140% of expected annual net energy production based on two years of rolling production
- **Damages for Failure to Perform**: Damages are limited to actual, direct damages; neither party is liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages regardless of cause
- **Force Majeure and Events of Default**: Each RAM contract shall include a force majeure definition and provision
- **Insurance**: IOU discretion, submitted in implementation advice letter
- **Scheduling Coordinator**: Where possible, the contracting IOU shall be the scheduling coordinator for each project using the RAM, and the IOU shall bear the risk of scheduling deviations if the generator provides the IOU with timely information on its

availability; the IOU can decline scheduling coordinator responsibilities only upon a written, affirmative request from the seller that the IOU not be the scheduling coordinator, or if unable to perform these duties

5. Project Viability Requirements

Bidder must demonstrate the following items with its bid. An IOU shall reject a bid that fails to demonstrate the following items. Each IOU shall adopt reasonable definitions and lists, related to:

- **Site Control:** Bidder must show 100% site control through (a) direct ownership, (b) lease or (c) an option to lease or purchase that may be exercised upon award of the RAM contract
- **Development Experience:** Bidder must show that at least one member of the development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project
- **Commercialized Technology:** Bidder must show the project is based on commercialized technology (e.g., is neither experimental, research, demonstration, nor development)
- **Interconnection Application:** Bidder must show that it has filed its interconnection application

6. Market Elements

a. **Preferred Locations**: The IOUs must provide the "available capacity" at the substation and circuit level, defined as the total capacity minus the allocated and queued capacity. The IOUs should provide this information in map format. If unable to initially provide this level of detail, each IOU must provide the data at the most detailed level feasible, and work to increase the precision of the information over time. This information is to be available in the advice letter implementing RAM and updated on a monthly basis.

   i. Each IOU should examine DG interconnection screening tools currently used to screen DG interconnection applications. The IOUs should evaluate how individual project studies could be automated to provide the requested data and a reasonable assessment of a DG project's impact on the distribution system.

ii. The IOUs should work with parties and Commission staff through the Renewable Distributed Energy Collaborative (Re-DEC) or other forums in order to improve the data, usefulness of the maps, and to discuss other issues related to the interconnection of distributed resources.

b. **Project Milestones**: Sellers shall submit a project development milestone timeline to the IOU upon RAM contract signing, and quarterly progress reports. The only enforceable milestone is the commercial operation data (COD) (subject to a one 6-month extension for regulatory delays).

c. **Relationship to Voluntary and Other Programs**: 1,000 MW capacity limit does not include capacity subscribed under the Existing FIT (up to 1.5 MW, subject to expansion to three MW under SB 32). SCE is permitted to draw down its capacity limit with the 21 contracts it selected in November 2010 from the RSC solicitation, if the CPUC approves these contracts

d. **FERC Certification**: No FERC certification as a QF is required for a project to be eligible for RAM

e. **Conveyance of RECs**: RECs transferred in relationship to the amount of the purchase (for full buy/sell, the IOU buys the RECs coincident with the entire output; for excess sales, the IOU buys the RECs coincident with the purchased excess energy)

7. Regulation and Commission Oversight

a. **Program modifications:** The Commission can modify any element of the program at any time through a Commission resolution.

b. **Advice Letter Review**: All executed RAM contracts from each auction are filed with the Commission in one Tier 2 advice letter.

c. **Program Evaluation**: RAM to be monitored and evaluated annually, with each IOU filing a report each year. The report shall be filed with ED and posted on the IOU's website. ED shall include RAM program information in the Commission's reports to the legislature on the RPS program.

d. **Data**:

Each annual report shall include information and evaluation on all relevant items and characteristics including but not limited to:

- Competition and competitiveness

- Auction design
- Time necessary to complete projects
- Auction timing
- Project status
- Anything else determined by ED to be necessary for a complete report

IOUs shall adopt a uniform report template with guidance from Energy Division

The first report shall include each IOU's proposal for a definition of a competitive market, proposed measurements of RPS markets generally, and proposed measurements of this RAM market specifically

As available over time, each report shall include data on:

- Measures of the requirements for a perfectly competitive market
- Measures of market power
- Seller concentration
- Data on each RAM results
- Information on the achievement of project development milestones for all executed RAM contracts
- Any other information necessary to present a complete report

e. **Public release of aggregated Data**:

i. IOUs and ED shall make the maximum amount of RAM data public, including the following:

- Names of participating companies and number of bids per company
- Number of bids received and shortlisted
- Project size
- Participating technologies
- Quantitative summary of how many projects passed each project viability screen
- Location of bids by county provided in a map format
- Information on the achievement of project development milestones for all executed RAM contracts

f. **Cost Recovery**: RAM costs may be charged to bundled and departing customers consistent with current practice

8. **Implementation Advice Letter:** PG&E, SCE, and SDG&E shall file Tier 3 advice letters within 60 days of the date this order. The implementation advice letters shall include:

- Procurement protocols
- RAM standard contract
- Program implementation details
- Timing of RAM auctions
- Specific amounts of capacity and type of resources in each auction over the next two years
- Explanation of any normalization procedures used for bid selection process
- Detailed description of the generation profiles and characteristics that correspond with each product bucket
- Description of how IOU-proposed product eligibility requirements will provide reasonable assurance that a bid for one product will, if selected, deliver energy in a manner that corresponds to the generation profile associated with that
- Identify seller concentration limit, if any
- Provide the preferred locations map and a description of how the maps were computed
- Provide a simple methodology to measure the status of project development milestones

(END OF APPENDIX A)

APPENDIX B

ACRONYMS

ACRONYMS FOR PARTY NAMES

ACRONYM	PARTY NAME
AG	California Attorney General
AreM	Alliance for Retail Energy Markets
Axio	Axio Power, Inc.
CAC	Cogeneration Association of California
CAISO	California Independent System Operator
CALSEIA	California Solar Energy Industries Association
CARE	Californians for Renewable Energy, Inc.
CEERT	Center for Energy Efficiency and Renewable Technologies
CESA	California Energy Storage Alliance
DRA	Division of Ratepayer Advocates
Environmental Council	Community Environmental Council
enXco	enXco, Inc.
EPUC	Energy Producers and Users Coalition
Farm Bureau	California Farm Bureau Federation
FuelCell Energy	FuelCell Energy, Inc.
Fortistar Methane	Fortistar Methane Group
First Solar	First Solar, Inc.
GPI	Green Power Institute
GreenVolts	GreenVolts, Inc.
IEP	Independent Energy Producers Association
LA Community College District	Los Angeles Community College District
PG&E	Pacific Gas and Electric Company
Recurrent	Recurrent Energy, Inc.
Reid	L. Jan Reid
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
Sempra Generation	Sempra Generation

Sempra Energy	Sempra Energy Solutions LLC
SFUI	Solutions for Utilities, Inc.
Sierra Pacific	Sierra Pacific Power Company
Sierra Club	Sierra Club
TURN	The Utility Reform Network

OTHER ACRONYMS

ACRONYM	ITEM OR NAME
AB	Assembly Bill
ALJ	Administrative Law Judge
AMF	Above market funds
CAISO	California Independent System Operator
CCA	Community choice aggregator
CEC	California Energy Commission
CHP	Combined Heat and Power
COD	Commercial Operation Date
Commission	California Public Utilities Commission
CSI	California Solar Initiative
D.	Decision
ED	Energy Division
ERAM	Electric Revenue Adjustment Mechanism
ESP	Energy service provider
FERC	Federal Energy Regulatory Commission
FIT	Feed-in Tariff
FPA	Federal Power Act
GHG	Greenhouse gas
GW	Gigawatt
IOU	Investor-owned utility
IPP	Independent power producer
ISO 4	Interim Standard Offer No. 4
kV	Kilovolt
LCBF	Least Cost-Best Fit
LCOE	Levelized cost of electricity
LSE	Load Serving Entity
LTTP	Long term procurement plan
MPR	Market price referent
MW	Megawatt
MWh	Megawatt-hour
PIER	Public Interest Energy Research
PIRP	Participating Intermittent Resource Program
PRG	Procurement Review Group
PURPA	Public Utilities Regulatory Policies Act

PV	Photovoltaic
QF	Qualifying Facility
RAM	Renewable Auction Mechanism
RD&D	Research, demonstration and development
REC	Renewable energy credit
RPS	Renewables Portfolio Standard
RSC	Renewables Standard Contract
SB	Senate Bill
SGIP	Self Generation Incentive Program
SMJU	Small and multi-jurisdictional utilities
SPP	Small power producer
TOU	Time of use
TOD	Time of delivery
UL	Underwriter's Laboratories

(END OF APPENDIX B)

APPENDIX C

DURATION OF PRICES AND TOD PERIODS

The Administrative Law Judge identified five rate design examples, and parties were asked to comment. (Ruling dated August 27, 2009, Appendix B.) We look at one example here. This example reveals tensions between short-term and long-term goals and responsibilities between various stakeholders. We encourage respondents and parties to continue to consider the problems identified by this example, and propose creative solutions.

In particular, respondents and parties were asked to comment on the following pricing example:[1]

- A price structure exclusively using energy payments; an initial price of $0.25/kWh paid by TOD factors set in the standard contract; the $0.25/kWh is paid in two parts over the life of the contract;
- The first part is payment of $0.20/kWh over the contract term;
- The second part is payment of $0.05/kWh; the $0.05/kWh is subject to adjustment at years 5, 10 and 15 to reflect the current market (e.g., formula in the contract based on an index to model seller's variable costs); and
- The TOD factors are updated once at year 10 to align with the current TOD profile of the buyer.

[1] August 27, 2009 Ruling, Attachment B, Item 12 at page 4 (also identified as Example D).

SCE identifies a particular problem with this example:[2]

"This example provides a fixed energy price component similar to the forecast energy price option provided to renewable Qualifying Facilities ("QF") under the Interim Standard Offer No. 4 ("ISO 4") contracts approved by the Commission in the early 1980s. As such, it embodies significant risks of overpayment for ratepayers (and a windfall for project owners) similar to those experienced during the life of the ISO 4 contracts.

The forecast energy payments under the ISO 4 agreement (which could be paid on either a levelized cents/kWh price or an escalating series of prices at the producer's election) was based on a forecast of utility avoided cost of energy that turned out to be much higher than actual market energy prices for most of the term of these contracts (which extended up to 30 years). As a result, ratepayers were saddled with overpayments for energy from these projects for many years. In light of this experience, the Commission should approach fixed payment schemes as proposed in this example with extreme caution.

More specifically, the proposal here to offer a fixed component for 80% of the energy price (*i.e.*, 20 cents/kWh) for the entire 20 year term of the contract imposes the same price risk on ratepayers for an even longer period than the ISO 4 contract did. [Footnote 20.] In addition to the extreme ratepayer risk associated with the fixed prices being above market, in the event that pricing under this example falls below market prices, project owners might be tempted to cease operating under the FIT and seek other opportunities to sell their power. Unless mitigated by appropriate security requirements or contract sanctions, this scenario would force SCE's customers to

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2 SCE Pricing Comments at 18-19.

bear the risk of having to pay for replacement power from other sources to make up the shortfall left by defaulting FIT producers. SCE strongly recommends against this scenario."

Footnote 20: Under the ISO 4 contract, the project owner was paid for energy under the forecast for a "First Period" that was limited to 10 years for contracts with a term of 20, 25 or 30 years. For contracts with a 5-year term length, the forecast was only available for the first 5 years. After the First Period, energy payments were based on avoided cost.

The risk identified by SCE is present in the current RPS program. For example, prices in the current RPS program typically are fixed for the duration of the contract, which is often 20 years. A 20-year fixed price essentially doubles the 10-year risk exposure experienced for the majority of the price under ISO 4. Further, 100% of the RPS price is fixed for the contract duration, whereas only a portion (about 20%) of the ISO 4 price was fixed for the contract duration, with the remainder (about 80%) fixed for 10 years or less, then subject to "true-up" to the market.

The fixed price risk in either the ISO 4 price or RPS price can result in either a "good" or "bad" outcome. Ratepayers will be apparent "winners," for example, if the prices set by contract for 10 years (ISO 4) or 20 years (RPS Program) turn out to be less than the market prices over the 10 to 20-year duration of the contract.[3] As SCE identifies, however, ratepayers will be apparent "losers" if the contract prices set for 10 to 20 years turn out to be more than the market prices over the same period.

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[3] This assumes, as noted by SCE, that security requirements and contract sanctions (e.g., deposits, damages) are sufficient to prevent an owner from ceasing operations and seeking other opportunities to sell its power.

In actuality, the comparison of contract price with market price is a comparison of dissimilar products.[4] Nonetheless, it demonstrates the tension that can arise when a long-term price set by contract differs from the current market price.

A similar tension can arise relative to TOD periods. Current TOD factors place most costs in the summer on-peak period (e.g., SCE's summer on-peak factor is 3.13; PG&E's is 2.20). California has a target of reaching 20% renewables by 2010, and seeks 33% of its generation from RPS resources by 2020. If successful in reaching the 33% goal, but if done with fixed TOD periods in 20 to 25 year contracts, California will achieve 33% of California's resources delivering electricity during a fixed summer on-peak period based on TOD factors in the contract set when the contract was signed. Demand, and the demand profile by TOD, however, may change over 20 to 25 years due to many factors.[5] While stability and predictability for both buyer and seller are advanced by fixed prices and TOD periods, they can also be undermined by pre-determined, inflexible

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[4] The price comparison confuses long-run and short-run (e.g., the market-based price for a 20-year contract (long-run) compared to the market-based price for a transaction of less duration (short-run, such as one day, one week, or one month); the comparison generally shows that the market-based long-run contract price is "too high" or "too low" compared to the market-based short-run price). The price comparison also confuses one long-run price with a different long-run price (e.g., market-determined contract price based on supply and demand in year x for a contract of "y" years duration compared to the market-determined contract price based on supply and demand in year x+5 for a contract of "y" years duration).

[5] If California's investment in the smart grid is successful, for example, California may be able to move the "peaking" part of the summer on-peak load to another period. If plug-in hybrid automobiles become a significant portion of California's vehicle fleet, demand in the off-peak period may grow substantially, perhaps changing the on-peak period, or at least altering TOD allocation factors. If storage technologies are successful, this may further alter demand and supply, thereby changing TOD periods or allocation factors (e.g., if plug-in hybrid automobiles are able to sell electricity back to the gird).

prices and TOD periods that bear little relationship to changing market conditions.[6] Changing prices and TOD periods (e.g., which results in RPS electricity being delivered in an on-peak period that is no longer on-peak) may require IOUs or developers to build additional resources to meet the changing economics and demand. Alternatively, IOUs might want or need to modify contracts with RPS resources to better match supply with demand. Contract modifications may be costly. Thus, inflexibility can lead to higher costs.[7]

Parties do not present a solution and we do not craft one here. Nonetheless, we must avoid creating an inflexible system where, if successful in reaching a 20% or 33% RPS resource base, we have fixed the economic prices and signals with contract requirements for RPS projects to sell electricity that is too expensive in the wrong TOD periods. We encourage IOUs and parties to continue to assess these concerns, and present reasonable solutions if and when appropriate, including the use of capacity rates parallel to those used in the annual RPS bid solicitation, or other devices or tools which will reasonably balance these tensions.

(END OF APPENDIX C)

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[6] See, for example, Recurrent Pricing Comments at 15.

[7] Some ratepayers would like the certainty of a rate fixed for the long term (e.g., 20 years). Similar tensions would occur, however, if the Commission set IOU ratepayer rates for the long-term. IOUs would face the risk of rates not recovering costs, recovering too much cost, or being out-of-alignment with TOD periods. We balance competing interests and adjust ratepayer rates periodically (e.g., via general rate cases every three years, or balancing accounts every year). We do not set ratepayer rates for 20 years, however (even though ratepayers make capital investment decisions for electricity consuming products which have product lives of 20 or more years).