BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

THE DIVISION OF RATEPAYER ADVOCATES' COMMENTS ON RENEWABLES PORTFOLIO STANDARD PLANS

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I. INTRODUCTION

Pursuant to the April 5, 2012 Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals (ACR), the Division of Ratepayer Advocates (DRA) respectfully submits the following comments on the Renewables Portfolio Standard (RPS) plans of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, filed May 23, 2012.

DRA generally supports the procurement plans of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E),[1] but recommends that the Commission:

- Require SCE and SDG&E to use success rates for executed contracts that are not yet online that better reflect the improving success rates for RPS contracts;
- Approve either a contract success rate for contracts executed but not on line of less than 100% for the Utilities **OR** a voluntary margin of over procurement. The Commission should not adopt both;
- Develop a reasonable, cost-based integration adder that reflects the cost of integration renewable energy into the systems of the Utilities; and
- Direct the Utilities to procure renewable energy products from all three RPS procurement product categories defined in Public Utilities Code Section 399.16 (b),[2] within the limits of Section 399.16(c)(1)-(c)(2).

II. DISCUSSION

A. SCE's Procurement Plan

DRA generally supports Southern California Edison Company's 2012 Renewables Portfolio Standard Procurement Plan,[3] which given the regulatory framework established by the

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[1] DRA's comments refer collectively to PG&E, SCE, and SDG&E collectively as Utilities or IOUs (investor–owned utilities).

[2] Unless otherwise specified, all further Section reference in DRA's comments are to the Public Utilities Code.

[3] Southern California Edison Company's 2012 Renewables Portfolio Standard Procurement Plan, filed May 23, 2012. (SCE RPS Procurement Plan).

new 33% RPS program proposes a reasonable process for planning for renewable procurement in 2012 and beyond, given the regulatory framework established by the new 33% RPS program. However, there are several areas of SCE's plan that merit further consideration.

DRA disagrees with SCE's pessimistic assumption as to the success of RPS contracts that are executed but not on line, which does not adequately reflect the recent performance of renewable contracts. Second, SCE proposes to acquire only Category 1 products,[4] which is likely the most expensive way to achieve RPS compliance and reflects an overly conservative view of regulatory risks associated with Category 2 and 3 products.

1. Portfolio Assessment

DRA agrees with SCE's assessment that it has only a long-term need for renewable products and no short-term need.[5] SCE will therefore only solicit projects that come online in 2018 and beyond.[6] DRA supports SCE's plan to consider the sale of excess Renewable Energy Credits (RECs) to optimize its portfolio value for ratepayers in Compliance Periods in which it is overprocured.[7] DRA also supports SCE's proposal to use a pro-rata procurement rate[8] which will assure that SCE slowly procures the RPS energy it needs to fulfill its long-term net short. A pro-rata procurement rate will therefore allow SCE to capture lower prices in the market should prices continue to decrease.

SCE does not propose to seek specific deliverability characteristics for renewable products but to instead allow the least-cost best-fit (LCBF) methodology to select for desirable production profiles in its valuation.[9] This proposal is reasonable and allows the LCBF process to work as designed to fairly evaluate projects against each other in a quantitative manner rather than carving out a set of deliverability characteristics or load profiles that a utility prefers on a qualitative basis.

DRA disagrees with some aspects of SCE's RPS Procurement Plan, and recommends that the Commission require SCE to revise its plan to reflect the recommendations discussed below.

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[4] Section 399.16(b)(1)(3) defines three types of RPS products, as described further at page 5.

[5] SCE RPS Procurement Plan, p. 3.

[6] SCE RPS Procurement Plan, p. 3; and Appendix E.1, Section 1.05

[7] SCE RPS Procurement Plan, pp. 6-7.

[8] SCE RPS Procurement Plan, p. 7.

[9] SCE RPS Procurement Plan, p. 7.

2. The Commission should direct SCE to use a success rate that better reflects recent RPS contract success rates.

SCE proposes an assumed success rate of 100% for contracted projects that are currently on line as well as for mandated programs including the Renewable Auction Mechanism (RAM), Feed-in Tariff (FiT) and its Solar Photovoltaic Program (SPVP). SCE also proposes a 100% success rate for re-contracting with projects of 20 MW or less.[10] These assumptions are reasonable because the likelihood of a contracted online project ceasing to produce during its contract is minute. RAM, FiT and SPVP programs are mandated and thus obligate a utility to "fill-in" for any failed capacity, and small projects are unlikely to need to go through a solicitation once their contracts expire; SCE will simply negotiate with them directly to comply with the specific program goals. In addition, SCE assumes a 0% rate of re-contracting for larger projects because SCE assumes these projects will go into a competitive solicitation. DRA supports this assumption and SCE's intent to use a competitive solicitation process for expiring large contracts.

However, SCE then proposes to use a 60% success rate even though some of the projects "in the pipeline" will actually be existing projects with expiring SCE contracts. Clearly once those go through a SCE solicitation – and presumably some will win and receive an executed contract – their rate of success will be close to 100%. In general, for executed contracts that are not yet on line (and apparently expiring contracts), SCE proposes a 60% success rate.[11] SCE explains that it:

> "currently accounts for the risk of project failure associated with projects that are not yet on-line by assuming 60% delivered energy from such contracts. This 60% success rate is modeled to represent project development success rates as well as any contingency that would make meeting the State's RPS goals less likely (e.g., delays due to transmission, curtailment, material shortages, load growth beyond that which is forecasted, or less than expected output from resources)."[12]

This success rate appears unrealistically low. The most recent data from the Utilities' March 2012 Compliance Reports demonstrate that the contract termination rate is decreasing as the market matures. The graph below illustrates the aggregated rate (by generation volume in

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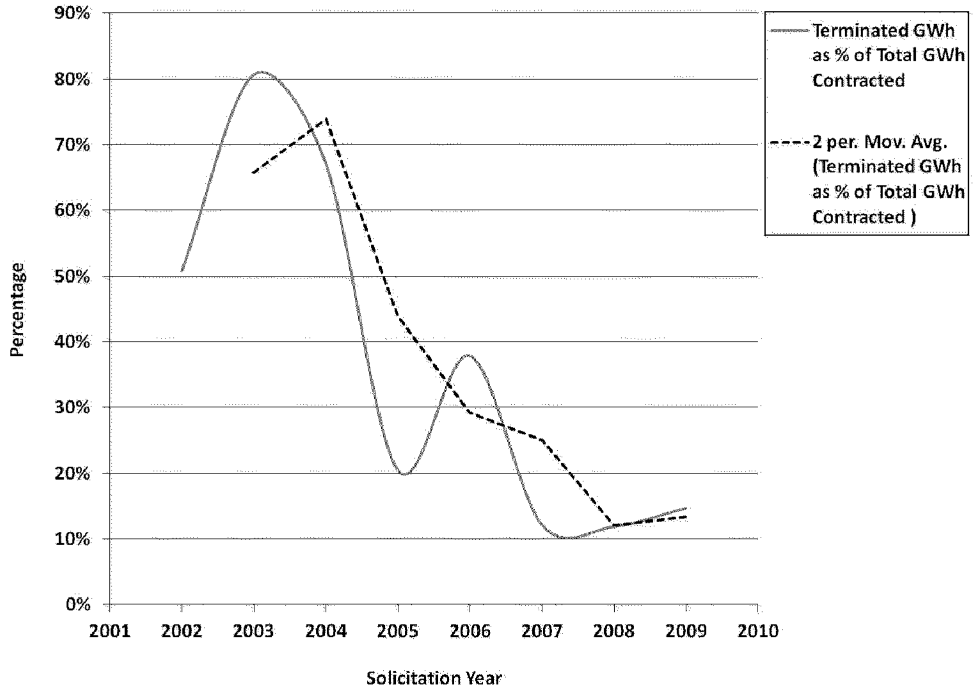
[10] SCE RPS Procurement Plan, p. 4.

[11] SCE RPS Procurement Plan, p. 18.

[12] SCE RPS Procurement Plan, p. 18.

GWhs) of contract terminations for the three IOUs. The average contract termination rate for projects solicited between 2002 and 2009 is 23%.[13]

Figure 1. Termination Rate for RPS Contracts Solicited 2002-2009 (by generation)



DRA supports SCE's proposed requirement that projects have at least an interconnection study,[14] and believes that such a requirement, combined with a more mature market and more experienced developers,[15] means that the success rate of future projects will continue to increase. Even taking into account other factors such as transmission delays and higher than expected load growth, DRA recommends that the Commission direct SCE and the other utilities to use a success rate higher than 60% to calculate their net short position. A success rate of 77% is one possibility as it assumes that the success rate of contracts from 2002 to 2009 will remain constant

[13] All data are from the March 2012 Compliance Reports filed by the IOUs. Bilateral contracts are included and assigned the year reported as "solicitation year" by the Utilities in the Reports. Projects solicited more recently than 2009 are not included to account for their lack of time to trigger a contract termination.

[14] SCE RPS Procurement Plan, p. 4.

[15] SCE cites developer inexperience as a significant factor in project failure [15] SCE RPS Procurement Plan, p. 8.

into the future. This assumption is conservative for the reasons discussed above and therefore gives the Utilities a margin of safety for their RPS procurement.

3. The Commission should direct SCE to consider RPS products from all three RPS procurement product categories authorized by Section 399.16(b)(1)-(3).

DRA questions SCE's intent to "narrow its next solicitation to Category 1 Products."[16] SCE contends that:

> "[b]ecause there is no limitation on the amount of Category 1 products that may be procured for RPS compliance, Category 1 resources provide more certainty and flexibility to SCE than Category 2 or Category 3 products. Accordingly, SCE's procurement protocol only requests proposals for renewable energy that qualifies under Category 1."[17]

This objective appears inconsistent with the requirements of the 33% RPS Program and likely to result in procurement of resources that are more expensive than necessary. Public Utilities Code Section 399.16(b) requires that a "*balanced* portfolio of eligible renewable energy resources shall be procured consisting of the following portfolio content categories."[18] Public Utilities Code Section 399.16(b)(1)(3) defines three RPS procurement product categories:

> "(1) Eligible renewable energy resource electricity products that meet either of the following criteria:
>
> A) Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source. The use of another source to provide real-time ancillary services required to maintain an hourly or subhourly import schedule into a California balancing authority shall be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category.
>
> (B) Have an agreement to dynamically transfer electricity to a California balancing authority.
>
> (2) Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

16 SCE RPS Procurement Plan, p. 3.

17 SCE RPS Procurement Plan, p. 26.

18 Public Utilities Code Section 399.16(b) (emphasis added).

(3) Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under the criteria of paragraph (1) or (2)."

Section 399.16(c) of the Public Utilities Code establishes minimum requirements for procurement in Category 1, and maximum requirements for products in Categories 2 and 3,[19] but does not eliminate the requirement that portfolios should be balanced, containing products from all three categories.

Currently, all products in SCE's RPS portfolio are either Category 1 or from pre-June 1, 2010 contracts,[20] which are not subject to category content restrictions.[21] By announcing its intent to consider only procurement of Category 1 products in future solicitations, SCE appears to espouse a strategy that ignores the direction of Section 399.16(b), which directs the procurement of balanced portfolios consisting of all three categories.

Moreover, the risks that SCE mentions regarding Categories 2 and 3 further decreased with the issuance of Decision (D.) 12-06-038 on June 21, 2012. In this Decision, the Commission resolved regulatory uncertainty regarding banking of Category 2 and 3 products. Yet SCE is being overly cautious in its unwillingness to consider Category 2 and 3 offers.

Finally, procuring some Category 2 and 3 products may allow SCE to meet its RPS obligations at a lower cost to ratepayers. RPS solicitations should be as competitive and robust as possible and excluding entire categories of products from solicitations will unnecessarily increase the cost of RPS compliance to ratepayers.

4. The Commission should direct SCE to assume that SCE will meet some of its RPS obligation in Compliance

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[19] Section 399.16 (c) provides that: "In order to achieve a balanced portfolio, all retail sellers shall meet the following requirements for all procurement credited towards each compliance period:(1) Not less than 50 percent for the compliance period ending December 31, 2013, 65 percent for the compliance period ending December 31, 2016, and 75 percent thereafter of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (1) of subdivision (b).

(2) Not more than 25 percent for the compliance period ending December 31,2013, 15 percent for the compliance period ending December 31, 2016, and 10 percent thereafter of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (3) of subdivision (b).

[20] SCE RPS Procurement Plan, p. 7.

[21] Section 399.16 (d); D.11-02-052, Ordering Paragraph 17.

Period 3 with banked procurement from Compliance Periods 1 and 2.

SCE's assumption of need in Compliance Period 3 appears to be predicated on uncertainty about being able to bank excess RPS procurement from Compliance Periods 1 and 2.[22] If that is correct, then SCE is being too conservative in its assessment of regulatory uncertainty. The Commission should direct SCE to include the realistic assumption that it will be able to bank eligible excess procurement. D.12-06-038 finalized the implementation of SB 2 (1x) with regard to banking. No further Decisions on banking and product categories are expected, and thus the issue of uncertainty in those areas has been resolved.

5. DRA agrees that the Commission should consider procedural changes to allow Utilities to respond more quickly to changing market conditions.

SCE observes that the Utilities "need the ability to make changes to their commercial documents to reflect changes in the renewable energy market,"[23] and contends that no one benefits if the IOUs are required to "issue solicitations with stale commercial documents that require substantial modifications before they can be executed."[24] SCE suggests that the Commission "consider ways to streamline the approval process so that Utilities can react more quickly to market and regulatory changes and reflect those changes in their solicitation materials." DRA supports this proposal to consider revisions to the process for approving changes to the Utilities' commercial documents so that necessary revisions can be accomplished efficiently.

DRA also supports consideration of the use of a Tier 2 Advice Letter (AL) for the approval of the sale of RECs and excess energy. SCE asserts "the Commission should permit the IOUs to obtain approval for the resale of renewable energy from existing facilities through a Tier 2 advice letter because there are very few issues for the Commission to consider in connection with such transactions."[25] DRA agrees that there are fewer issues that require stakeholder input on and Commission review of the resale of energy from existing facilities, than with the approval of contracts for new facilities. The Commission should therefore approve this

[22] SCE RPS Procurement Plan, p. 3, p. 5, and Appendix C.

[23] SCE RPS Procurement Plan, p. 16.

[24] SCE RPS Procurement Plan, p. 16.

[25] SCE RPS Procurement Plan, p. 24.

change unless other stakeholders can point out flaws with the Tier 2 AL process for these transactions. DRA notes that the *purchase* of RECs by other investor-owned utilities should remain a Tier 3 AL.

6. Minimum Margin of Over Procurement

SCE states that its 60% success rate used to establish the long/short position makes additional over procurement unnecessary.[26] DRA agrees that if the Commission is assuming a certain failure rate within the projection of a utility's net short position, then an additional margin of over procurement is duplicative. SCE contends that:

> "The Commission should avoid mandating a method for IOUs to calculate the minimum margin of procurement and should not attempt to impose a one-size-fits-all approach. As many of the projects in SCE's portfolio become operational, SCE will face different risks. The risks associated with project failure will be replaced by less significant risks of projects generating below full capacity."[27]

DRA agrees that the Commissions should avoid requiring a specific margin of over procurement for the IOUs unless the IOU also assumes a 100% success rate. In that case, DRA would support a common methodology for all three utilities. In no event should the Commission adopt both a minimum margin of procurement AND something other than a 100% success rate since the margin is intended to counter future project failure and other unforeseen circumstances. Such a "belt and suspenders approach" could unnecessarily increase the cost to ratepayers of meeting the 33% RPS.

7. Integration Costs

As discussed further below, DRA agrees with SCE that the integration costs for renewable energy should be non-zero.[28]

B. PG&E's Procurement Plan

DRA generally supports PG&E's 2012 RPS Procurement Plan as many of the changes proposed will aid PG&E in meeting its 33% RPS by 2020 goal. In particular, DRA supports PG&E's removal of the Tax Credit Mitigation Option for Sellers and agrees that the Commission should consider renewable integration costs as part of a utility's solicitation and shortlisting

[26] SCE RPS Procurement Plan, p. 18.
[27] SCE RPS Procurement Plan, pp. 18-19.
[28] SCE RPS Procurement Plan, Appendix F.1 Least-Cost Best-Fit Methodology. p. 5.

selection process. However, DRA disagrees with some components of PG&E's 2012 Procurement Plan. As mentioned above, DRA does not support the inclusion of an additional voluntary margin of over procurement unless the utility assumes a 100% success rate. DRA requests that this change be made to PG&E's RPS Procurement Plan.

1. PG&E Should Balance a Voluntary Margin of Over Procurement with Banked Surplus Energy and its Project Failure Rate

PG&E's 2012 RPS Procurement Plan proposes to include a voluntary margin of over-procurement in its renewable portfolio. PG&E states this voluntary margin could help to mitigate the variability in its load and RPS deliveries; variability in RPS deliveries that is unrelated to project failure and delays related to new project development.[29] Such a voluntary margin of over procurement would account for factors such as hydropower variability, curtailment due to congestion or integration, force majeure events, increases in load due to migration, and the right of Sellers to reduce contractual delivery guarantees.[30]

PG&E's proposed voluntary margin of over procurement would be equal to an additional 1 – 2% of total retail sales for an average additional, long-term over procurement margin of 1.5%.[31] PG&E also proposes to adjust the percentage of its voluntary margin of over procurement to account for fluctuations in its banked surplus.[32] PG&E justifies the inclusion of this voluntary margin of over procurement as this procurement strategy is permitted per §399.13 (a)(4)(D) of the RPS statute.[33]

Based on this information, DRA understands that PG&E has elected to introduce this voluntary margin of over procurement to make up for <u>annual</u>, unaccounted for changes that will affect its expected RPS deliveries. If this is the case, it is not clear why PG&E will need to

[29] Pacific Gas & Electric Company Renewables Portfolio Standard 2012 Renewable Energy Procurement Plan (Draft Version) May 23, 2102, p. 52. (PG&E RPS Procurement Plan) p. 52.

[30] PG&E RPS Procurement Plan, p. 52.

[31] PG&E RPS Procurement Plan, p. 53.

[32] PG&E RPS Procurement Plan, p. 53.

[33] Section 399.13 (a)(3) requires the Commission to adopt by rulemaking various aspects of the 33% RPS program, including "[a]n appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to mitigate the risk that renewable projects planned or under contract are delayed or canceled. This paragraph does not preclude an electrical corporation from voluntarily proposing a margin of procurement above the appropriate minimum margin established by the Commission." Public Utilities Code 399.13(a)(4)(D).

procure an additional 1 – 2 % of <u>total</u> retail sales across all three compliance periods if such a margin is needed to make up for <u>annual</u> variations in load and unforeseen delivery shortfalls that may or may not occur.

DRA recommends that this across the board margin of over procurement should only be utilized if PG&E assumes a 100% success rate for contracts executed but not yet on line. As stated above, such a "belt and suspenders" approach is unnecessary and will be costly for ratepayers depending on the type of product category PG&E will be purchasing this additional 1 – 2% margin. An additional margin of over procurement would also be unnecessary for compliance periods in which PG&E is already over procured.

PG&E presently assumes only a 78% rate for contracts executed but not online.[34] DRA does not object to this assumed 78% success rate and thinks this is an appropriate assumption given the historic RPS project development success rate. While PG&E assumes a higher contract success rate than both SCE and SDG&E, an additional margin of over procurement to account for annual load variation is not warranted. PG&E should assume a 100% success rate for contracts executed but not online before requesting a voluntary margin of over procurement.

To avoid confusion about the use of a margin of over procurement, DRA recommends that the Commission establish clear guidelines for the IOUs on how to utilize this tool with other procurement safeguards such as banking provisions and accounting for projected failure rates. DRA recommends the following measures to ensure that the IOUs' utilization of a voluntary margin of over procurement is consistent with these other procurement safeguard mechanisms.

First, consistent with Section 399.13(a)(4)(D), the margin of over procurement should be at the discretion of the IOU to propose and the Commission to authorize. In instituting a margin of over procurement, the IOU should only be allowed to apply this voluntary margin on an annual basis or by compliance period, but not throughout the remaining years of the RPS program through 2020. That is, a voluntary margin of over procurement should only be authorized to make up for <u>annual</u> or compliance period variations in RPS deliveries and other unanticipated changes, **not** long-term issues related to project development success rates. It does not make sense to allow an IOU to procure an additional margin of resources across compliance periods where the IOU is already over procured as this would be too costly for ratepayers.

[34] PG&E RPS Procurement Plan, p. 44.

Second, in requesting to establish a voluntary margin, the IOU should also be required to justify why this margin is necessary and specify the type of product category resources it anticipates procuring to make up this additional margin. Within the limits required by Section 399.16(c)(10-(2)) DRA recommends that the IOUs first consider Category 3 products (RECs) or other short-term options (Category 2 products) to account for annual, unforeseen and short-term shortages. The Commission should then authorize or reject the IOU's proposal on a compliance period cycle or in the biennial RPS Procurement Plan cycle and establish a cap on the IOUs' voluntary margin of over procurement amount.

Finally, if a utility wants to assume, for example, an annual 1 – 2% voluntary margin of over-procurement for one compliance period, the IOU should first be required to deduct any banked RPS energy from this percentage before procuring an additional margin of renewable resources to make up for unexpected shortfalls or variability in production. As noted above, PG&E states that it intends to adjust its margin of additional procurement to account for its banked surplus and DRA supports this recommendation. A utility should not retain surplus or banked energy and also elect to procure additional resources above and beyond an assumed project failure rate. This could result in excess costs for ratepayers.

All of these tools — over procurement mechanisms, project failure rates, and banking — can provide a buffer and procurement safeguard for the IOUs to meet their compliance period targets. Before authorizing an additional margin of over procurement for any of the IOUs, the Commission should ensure that the IOU has established a balance between the use of this tool with other procurement safeguards like banking and projecting failure rates. Such an approach, when considered in the context of these other procurement safeguards, will ensure that cost containment is not jeopardized.

2. The Commission Should Consider Integration Costs for Renewable Resources in this 2012 RPS Procurement Plan Cycle

PG&E's 2012 RPS Procurement Plan describes the need for an explicit adjustment for integration costs related to intermittent renewable energy projects in its future RPS solicitation valuation. PG&E states that this adder is necessary "to account for the increased cost of dispatching additional generators and procuring sufficient ancillary services from flexible resources….”[35] PG&E proposes to apply an integration cost adder of $8.50/MWh to all intermittent resources, but may adjust this price depending on the level of intermittency.[36] Neither SCE nor SDG&E has proposed a specific integration cost adder in this RPS Procurement Plan cycle although SCE states that it will use integration adders “to the extent allowed by the Commission.”[37]

DRA agrees that the Commission should consider the cost associated with integrating such resources into the total price of renewable generation.[38] After years of mandating a zero integration cost, now would be an appropriate time for the Commission to move forward with the adoption of an integration cost adder that reflects the costs of integrating renewable energy. The IOUs have at least six years of historical cost information to rely on and use as the basis for formulating or estimating the price of a renewable integration cost adder. Thus, it would be worthwhile for the Commission to initiate a stakeholder process to arrive at a reasonable integration cost adder or calculation methodology that can be utilized by all three IOUs in their RPS least-cost, best fit (LCBF) bid evaluations.

Whether to include an integration cost adder into the price of renewable resources is not a new issue. In their draft 2010 RPS Procurement Plans, both SDG&E and SCE advocated that the Commission adopt such an adder after the Commission retained a zero-integration cost.[39] When it approved the 2010 RPS Procurement Plans, the Commission declined to adopt a non-zero integration cost adder, stating that:

> “We have previously rejected proposals for non-zero integration cost adders (in D.07-02-011 an D.08-02-008). Nothing presented here changes our view. IOUs must exclude language in Final 2011 Plans that would incorporate use of non-zero integration cost adders, including their use in LCBF evaluation of bids. Moreover, we said before that such costs, if any, need to be developed with public review and comment. CalWEA, LSA and TURN argue that

[35] PG&E RPS Procurement Plan p. 63.

[36] PG&E RPS Procurement Plan p. 63.

[37] SCE 2012 RPS Procurement Plan, p. 5 of Appendix F.1, Least-Cost Best-Fit Methodology.

[38] Scoping Memo and Ruling of Assigned Commissioner, July 18, 2011, Attachment A, Preliminary Issues List of Issues for this Proceeding, p. 2.

[39] D.11-04-030, p. 22.

> an adder should only be used if it is developed in a public forum and, in addition, with Commission supervision. We agree."[40]

Although the $8.50/MWh integration cost adder proposed by PG&E was adopted by the Commission in the 2010 long-term procurement planning proceeding (LTPP) Rulemaking (R.)10-05-006, the Commission should not assume this price accurately reflects the cost of integrating intermittent resources today. There are several reasons why. First, the *Standard Planning Assumptions (Part 2 – Renewables) for System Resource Plans* that PG&E references as the basis for the integration cost of $8.50/MWh was, according the footnote, "developed during E3's Greenhouse Gas modeling for the Commission in Rulemaking (R.) 06-04-009" and is being used "in the absence of more rigorous analysis of California-specific integration costs."[41] Second, an updated integration cost adder has not been proposed or included in the 2012 LTPP proceeding, Rulemaking (R.)12-03-014. More importantly, it is unclear how this $8.50/MWh was calculated and what assumptions went into this calculation to arrive at this figure. Since the assumptions were developed for a Rulemaking in 2006, these assumptions may be outdated and thus lead to inaccurate cost calculations. Accordingly, it would thus be beneficial for the Commission, IOUs and stakeholders to have a breakdown of these variables and assumptions in this proceeding.

The Commission should not adopt the integration cost adder proposed by PG&E in the absence of a more robust process. PG&E's proposal provide a reasonable starting point since it was adopted and used in the 2010 LTPP Standardized Planning Assumptions. Before this figure should be approved as the renewable integration cost, the methodology behind the calculation of this proposed adders should be thoroughly explained and vetted by parties. If PG&E or any other IOU would like to institute an integration cost adder into its LCBF bid evaluation methodology going forward, this adder should, to the best extent possible, be an accurate reflection of the price of integrating renewable resources in California. The 2012 LTPP is considering the need for flexible capacity in the form of additional gas-fired generation order to support intermittent renewable resources.[42] It is possible that some of the support for

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40 D.11-04-030, p. 23.

41 Attachment 2 "standardized Planning Assumptions (Part 2 – Renewables) for System Resource Plans" at 18.

42 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, May 17, 2012, in R.12-03-014, p. 9.

intermittency and load variability could be provided at lower cost by firming and shaping products. But regardless of the products chosen to support renewable integration, they will come at a cost to ratepayers that should be recognized by adopting an integration cost adder. Therefore, the Commission's work to develop a renewable integration cost adder should be developed in line with the renewable integration work and modeling occurring the 2012 LTPP proceeding, R.12-03-014.

It is clear that more collaborative work and analysis should be done before this \$8.50/MWh integration cost adder is finalized in PG&E or any other IOUs' 2012 RPS Procurement Plan and utilized in the LCBF bid ranking methodology. Thus, it would be worthwhile for the Commission to initiate a stakeholder process in this round of RPS Procurement Plans to vet the variables for a renewable integration cost adder calculation.

3. DRA Supports PG&E's Proposed Changes to its 2012 RPS Solicitation

PG&E proposes several changes to its 2012 RPS Solicitation to streamline its selection and shortlisting process. Some of PG&E's deviations from previous solicitations include a preference for long-term contracts (10+ years), requiring Sellers to have a least a Phase I interconnection study to bid into the request for offer (RFO) solicitation, a preference for power purchase agreements (PPAs) instead of both PPAs and utility-owned/turnkey generation, and a specific need for projects coming online in 2019 and 2020 during compliance period 3.[43] Among the list of changes, PG&E has also proposed to eliminate the Tax Credit Mitigation Option that it made available to developers in previous Form PPAs. This PPA provision allowed developers to seek price adjustments if the production tax credits (PTCs) or investment tax credits (ITCs) were to expire. PG&E proposes to eliminate this option for developers in order to "receive offers from developers who are committed and able to fulfill contractual requirements without the guarantee of financing subsidies."[44]

DRA supports PG&E's recommendation to eliminate the Tax Credit Mitigation Option from its Form PPAs. In the past DRA has advocated for the removal of this provision from the IOUs' Form PPAs as a costly provision for ratepayers. With a larger number of developers to select from in California's renewable market and the uncertainty of the extension of the PTCs

[43] PG&E RPS Procurement Plan, p. 56 – 57.

[44] PG&E RPS Procurement Plan p. 14, 36.

and ITCs past 2016, it is important that the IOUs become more selective about the projects they chose to shortlist to meet their 33% RPS target. PG&E's recommended PPA revision, which would require projects to be financially more self-sufficient and less reliant on subsidies is a step in that direction. The Commission should therefore support PG&E's effort to select and shortlist more self-sustaining and financeable renewable energy projects.

C. SDG&E's Procurement Plan

DRA finds few issues with SDG&E's 2012 RPS Procurement Plan. DRA supports SDG&E's proposed revision to its 2012 RPS solicitation to include stronger and more detailed collateral requirements. However, DRA disagrees with SDG&E's assumption that there will be a high rate of failure, similar to DRA's objection to SCE's assumed rate of failure.

1. SDG&E's 60% Assumed Success Rate is Too Low

For projects that have been approved by the Commission but have not yet begun to deliver energy, SDG&E assumes a 60% success rate.[45] DRA opposes SDG&E's 60% success rate as this number does not accurately reflect current trends in the number of RPS projects that successfully deliver energy. In its June 12th presentation at the Commission on its RPS need methodology, SDG&E cited a 50% historical failure rate.[46] Both the IOUs and renewable developers have become more experienced in developing renewable projects in California, so DRA finds it highly unlikely that SDG&E's assumed success rate going forward is only 10% greater than this historical average. As shown on page 4, Figure 1 of these comments, the average failure rate for projects solicited between 2002 and 2009 was approximately 23%, which correlates to a success rate of 77%. Therefore, the success rate for projects in development should be closer to PG&E's assumed 78% success rate.[47] DRA recommends the Commission require SDG&E to increase its success rate to better align with the current trend and success rate for renewable projects.

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[45] SDG&E RPS Procurement Plan, p. 4.

[46] RPS Need Methodology Workshop, June 12, 2012, p. 4. *See:* http://www.cpuc.ca.gov/NR/rdonlyres/46E6845B-4D2F-4D36-B1F9-7B668CC78AD5/0/SDGENetShortWorkshopPresenation.pdf

[47] PG&E RPS Procurement Plan p. 44.

2. DRA supports the addition of more detailed collateral requirements throughout the procurement process in SDG&E's 2012 RPS Solicitation.

In SDG&E's 2011 RFO, SDG&E required short-listed projects to provide an initial security deposit. This security deposit was to be the lesser of either $3/kW of the project's nameplate capacity, or $100,000. Additionally, SDG&E required "annual MWh" based construction period and delivery term securities.[48]

In Appendix E of SDG&E's 2012 RPS Procurement Plan, SDG&E proposes revising its credit provisions for offers longer than two years. SDG&E proposes to require a $100,000 security deposit for short-listed projects and higher "annual MWh" based Commission-approval, development period, construction period, and delivery term securities which grow larger the closer the project is to its Commercial Operation Date (COD).[49] DRA supports this revision as it should encourage greater success among developing projects and reduce delays in COD dates. DRA also recognizes that with regards to contract failure, the inclusion of this provision should cover some of the presumably higher replacement costs that would be borne by SDG&E's ratepayers for having to procure an equivalent product in the short-term to make up for such project delays or failures.

D. DRA Supports the ACR's Proposal for the Preliminary Independent Evaluator (IE) Report to be Included in the RPS Procurement Plan with Protections for Confidential Information.

In the ACR from April 5, 2012, the Commission proposes splitting the preliminary Independent Evaluator (IE) report into two parts and including the portion of the IE's preliminary report on bid solicitation/LCBF with the IOUs' proposed procurement plan. Currently, after the RPS Procurement Plan is issued and bids are solicited and shortlisted, the preliminary IE report is submitted with the IOU's shortlist. A final IE report is also included with each of the individual IOU's advice letters submitted to the Commission for approval of the contracts that result from the solicitation.[50]

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[48] SDG&E's 2012 RPS Procurement Plan, Appendix E of SDG&E's 2012 RPS Procurement Plan, section deleted from p. 28 of RFO.

[49] SDG&E's 2012 RPS Procurement Plan, Appendix E of SDG&E's 2012 RPS Procurement Plan, pp. 27-28.

[50] ACR, p. 18.

DRA agrees with Energy Division's (ED) assessment that including the least-cost, best fit (LCBF) section of the preliminary IE report with the IOUs' proposed procurement plan will provide greater clarity for parties interested in submitting bids.[51] DRA also agrees with SDG&E's conclusion that ED's proposal will encourage more participation in the bidding process.[52] However, DRA also recognizes the issue raised by SDG&E on the confidential treatment of market sensitive information that could be included in the IE report. In its plan, SDG&E expresses a concern that including "in great detail how the LCBF criteria are used in bid evaluation"[53] could lead to bid gaming. Accordingly, DRA suggests that ED develop criteria to redact sensitive information that could compromise the integrity of the bidding process from the portion of the preliminary IE report that would be included with the IOU's proposed procurement plan.

It is unclear how the inclusion of preliminary IE report's "recommendations for improving the LCBF methodology"[54] with an IOUs' proposed procurement plan would help encourage clarity or participation in the bid process. DRA agrees with SDG&E that the best time for providing recommendations is after the evaluation. This would reduce the burden on both the IOU and IE and allow the IE to continue providing confidential and candid recommendations to the IOU throughout the process.[55]

III. CONCLUSION

DRA looks forward to refining its recommendations in response to the opening comments of other parties.

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[51] ACR, p. 18.

[52] SDG&E RPS Procurement Plan, pp. 28-29.

[53] SDG&E RPS Procurement Plan p. 29.

[54] ACR, p. 19.

[55] SDG&E RPS Procurement Plan, pp. 28-29.

Respectfully submitted,

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June 27, 2012

VERIFICATION

I, Diana L Lee, am counsel of record for the Division of Ratepayer Advocates in proceeding R.11-05-005, and am authorized to make this verification on the organization's behalf. I have read the

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filed on June 27, 2012. I am informed and believe, and on that ground allege, that the matters stated in this document are true.

I declare under penalty of perjury that the foregoing are true and correct.

Executed on June 27, 2012 at San Francisco, California.

/s/ DIANA L. LEE
Diana L. Lee
Staff Counsel