BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program. U 39 E	Rulemaking 11-05-005 (Filed May 5, 2011)

PACIFIC GAS AND ELECTRIC'S (U 39 E) OPENING COMMENTS ON THE PROPOSED DECISION OF ALJ DEANGELIS CONDITIONALLY ACCEPTING 2012 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN OFF-YEAR SUPPLEMENT

CHARLES R. MIDDLEKAUFF
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 972-5952
E-Mail: mgml@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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Pursuant to the California Public Utilities Commission's ("Commission") Rule 14.3, Pacific Gas and Electric Company ("PG&E") provides the following comments on the October 9, 2012 Proposed Decision of ALJ DeAngelis Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Off-year Supplement (the "Proposed Decision").

I. INTRODUCTION AND OVERVIEW

PG&E generally supports the Proposed Decision and appreciates the Commission's diligent effort to ensure that PG&E's 2012 Renewable Portfolio Standard ("RPS") Request for Offers ("RFO") can begin prior to the end of 2012. In these comments, PG&E recommends that the Proposed Decision be modified in the following ways:

- Integration Costs: The Commission should adopt PG&E's proposed adder as a preliminary and reasonable proxy for expected integration costs. There is no support in the record for the Proposed Decision's election to ignore integration costs completely, nor is it reasonable for the Commission to do so.

- Portfolio-Adjusted Value: The Decision should approve PG&E's Portfolio-Adjusted Value methodology, as revised and described in more detail in

Attachment 1 to these comments, since it increases the transparency of the least-cost, best-fit ("LCBF") bid evaluation process and will lead to a more efficient and cost-effective solicitation.

- Phase II Study Requirement: The Phase II Study requirement will increase RPS Program costs and complexity without providing any significant incremental benefit to customers. The Phase II requirement should be eliminated and the transmission cost upgrade cap retained.

- Shortlist Expiration: The Commission should modify the Proposed Decision to clarify that the IOUs have 12 months to execute PPAs from the time that the Commission approves the shortlist, rather than from the time of shortlist submission.

- Independent Evaluator ("IE") "Good Faith" Evaluation: The Commission should not require the IE to opine on whether IOUs acted in "good faith," given the lack of any good faith obligation to bidders on IOUs' shortlists.

- Imperial Irrigation District ("IID") Import Capacity: The Commission should clarify that for the purpose of offer evaluation, PG&E may continue to assume no constraint on imports from IID rather than requiring the IOUs to coordinate negotiations with IID bidders.

- Timing of Shortlist Submission: The Commission should not set an arbitrary date for the shortlist submission, but rather should grant the IOUs flexibility to provide bidders notice of the shortlist and to file their shortlists anytime within four months of the close of bidding.

- Filing of Conformed RPS Plans: The final decision should clarify that the 14 days for filing conformed plans runs from mailing of the decision and excludes state holidays.

With these modifications, which are more specifically discussed below and shown in the revisions to the finding, conclusions, and orders appended as Attachment 2 to these comments, PG&E supports adoption of the decision.

II. COMMENTS ON SPECIFIC ISSUES

A. Ignoring Integration Costs Is Unreasonable, Not Supported by the Record, and Will Undermine the Cost-Effective Implementation of the RPS Program.

Nothing in the record for this proceeding supports the Proposed Decision's finding, through its rejection of an integration cost adder, that the need to integrate intermittent renewable resources within the electric grid has no impact on the value of those resources. In fact, as PG&E noted in its reply to opening comments on the 2012 RPS Plans, the great majority of parties support moving away from the past policy of assuming no integration costs.[1/]

As a threshold matter, there is no substantial evidence to support the Proposed Decision's determination that no integration adder should be included. In contrast, the record supports adoption by the Commission of PG&E's proposal to use an integration cost adder of approximately \$8.50/MWh[2/] for bids from intermittent resources. Most importantly, PG&E's proposal is based upon and consistent with the integration cost assumptions developed by an independent Commission consultant and adopted by the Commission for use as a standard planning assumption in the Long-Term Procurement Plan ("LTPP") proceeding.[3/] Moreover, PG&E's proposal was included in PG&E's draft 2012 RPS Plan submitted in May 2012,[4/] and was therefore subject to public notice and comment, including opportunities for other parties to address the proposal in their opening and reply comments on the draft RPS Plans.[5/] Third, as

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1/ *See* PG&E Reply to Comments on RPS Plans and New Proposals, filed July 18, 2012 at 15, fn. 40.

2/ PG&E's specific proposal was to use \$7.50/MWh in 2008 dollars, which equates to roughly \$8.50/MWh in 2013 dollars.

3/ PG&E 2012 Renewable Energy Procurement Plan (Draft Version), filed May 23, 2012 ("PG&E Draft 2012 RPS Plan – May 2012 Draft") at 63 (citing the February 10, 2011 Administrative Law Judge's Ruling Modifying System Track I Schedule and Setting PreHearing Conference, Attachment 2, "Standardized Planning Assumptions (Part 2 – Renewables) for System resource Plans" issued in R.10-05-006 at 28). *See also* Independent Energy Producers Association ("IEP") Opening Comments on RPS Plans at 14 (noting that PG&E's proposed adder was developed for modeling); Division of Ratepayer Advocates ("DRA") Comments on RPS Plans at 13 (noting that the proposed adder was adopted by the Commission in the LTPP rulemaking).

4/ PG&E Draft 2012 RPS Plan – May 2012 Draft at 63.

5/ While no party specifically defended an integration cost adder of zero as reasonable, several parties expressed concern regarding the adoption of a non-zero adder without stakeholder input and a public process. *See e.g.,* Opening Comments of BrightSource Energy Inc. on 2012 RPS Plans at 2; Opening Comments of Solar Reserve on the 2012 RPS Plans at 8-9; Opening Comments of the DRA on 2012 RPS discussed below, PG&E's proposed integration adder is generally consistent with integration charges adopted through other public processes. Finally, no party has set forth specific countervailing evidence to suggest that PG&E's proposed $8.50 adder is unreasonable. Thus, the record in this proceeding supports adoption of PG&E's proposal and does not support the Proposed Decision's rejection of any integration cost.

Renewable integration costs are real, and they should be used to make new RPS resource procurement decisions so that the IOUs' customers realize the greatest possible value from the RPS program. Requiring the IOUs to ignore real costs and to use a zero integration cost adder will result in suboptimal procurement decision-making both for project selection in the RFO and consideration of contract extensions and/or amendments to existing contracts. Importantly, PG&E's proposal would allow IOUs to take into account exceptional cases in which an intermittent resource is reasonably expected to require less integration services than other intermittent resources. For example, a solar thermal facility with integrated storage capability may warrant a reduced adder.

The Proposed Decision errs when it states that the Commission is developing a renewable integration cost adder in the 2012 LTPP proceeding, R.12-03-014, and, on that basis, defers the issue to that proceeding.[6/] The scope of R.12-03-014 does not currently include a determination of a proxy integration cost of renewable resources to be used as an input in the RPS LCBF methodology. Track 2 (System Reliability) of the LTPP proceeding will consider the need for new flexible capacity within CAISO to integrate variable resources and maintain reliability over

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Plans at 12; Opening Comments of the Large-Scale Solar Association on 2012 RPS Plans at 5-7; Opening Comments of the IEP on 2012 RPS Plans at 9; Reply Comments of The Utility Reform Network on 2012 RPS Plans at 3-4.

6/ Proposed Decision at 27.

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a long-term planning horizon.[7/] However, determining the need for new flexible resources is a fundamentally different exercise than determining the cost to integrate intermittent resources, which requires allocating the balancing resources' fixed and variable costs between load and generation resources.[8/] Integration costs are not exclusively related to the cost of new resources that may be identified as needed in Track 2; they are already incurred today when existing resources are committed, or when they are dispatched at sub-optimal points, to cover the variability and uncertainty of wind and solar generation.

The Federal Energy Regulatory Commission ("FERC"), which has jurisdiction and competence to evaluate the cost to provide transmission services, has already recognized that renewable integration costs are real[9/] and has overseen public proceedings that resulted in integration charges similar to the adder PG&E proposes.[10/] In accordance with these precedents,

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7/ *See* R.12-03-014, *Scoping Memo and Ruling of Associated Commissioner and Administrative Law Judge,* May 17, 2012, at 10; R.12-03-014, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans*, March 22, 2012, at 5.

8/ Even if the Commission were to amend the current scope of the LTPP to include consideration of the renewable integration cost adder issue, it should still adopt PG&E's proposal on an interim basis until a final determination is made in that docket. Allowing for consideration of integration costs on an interim basis now will result in cost savings for customers over the life of the RPS contracts while at the same time providing a public forum to refine integration cost estimates in the future.

9/ *See, e.g., Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012)*; Westar Energy, Inc.,* 130 FERC ¶ 61,215 (2010).

10/ For example, Puget Sound Energy, Inc. ("Puget") recently filed an all-party settlement with FERC to revise its Open Access Transmission Tariff to incorporate a new differentiated regulation charge to integrate the output of intermittent generators. The settlement proposes a base rate integration charge on intermittent generators of $1.55/kw-month, or about $7/MWh, assuming a 30% capacity factor. *See* Stipulation and Offer of Settlement of Puget Sound Energy , Inc. under ER11-3735, et. al., filed on September 14, 2012 in FERC Docket ER11-3735, at 4. Similarly, Bonneville Power Authority's ("BPA") rate schedule allows it to charge wind generators up to $1.23/kw-month, or about $6/MWh, assuming a 30% capacity factor, for a Variable Energy Resource Balancing Service, which includes regulation, following service, and imbalance reserves. *See* BPA, 2012 Transmission and Ancillary Service Rate Schedules, at 62-63 (available at http://transmission.bpa.gov/Business/Rates/documents/2012_rate_schedules.pdf). The true integration cost in BPA's balancing authority area would be still higher, given authority BPA has to limit wind generation to wind schedules and curtail wind schedules to actual generation when there are insufficient balancing reserves available. *See* Summary of Dispatcher Standing Order 216 – Phase II Update, BPA, March 20, 2012 (available at http://transmission.bpa.gov/wind/op_controls/dso216_phase_II_summary.pdf).

and the record in this proceeding, the Proposed Decision should be modified to adopt PG&E's proposal as reasonable, subject to modification as the record continues to develop over time.[11/] Integration costs exist today and will continue to increase over time, as more wind and solar resources are added to the system. Assuming, as the Proposed Decision does, that they do not exist is neither supported by the record nor allows for cost-effective implementation of the RPS program.

B. The Commission Should Adopt a Revised Version of PG&E's Portfolio-Adjusted Value Methodology to Increase LCBF Transparency and Accuracy.

The Proposed Decision would direct PG&E to remove its Portfolio-Adjusted Value ("PAV") methodology from its 2012 RPS Solicitation Protocol given concerns that the methodology lacks sufficient clarity to allow a bidder to understand how it would be affected.[12/] The Proposed Decision further states that the PAV methodology cannot be adopted without additional information regarding how the methodology would work so that the Commission could ensure that the PAV methodology does not duplicate the existing LCBF variables.[13/]

The Proposed Decision should be modified to approve the PAV methodology because PAV quantifies, systematically and explicitly via the LCBF consideration of portfolio fit, PG&E's preferences for project location, delivery start dates, and contract term lengths (tenor). The Proposed Decision itself approves PG&E's use of these "varying preferences."[14/] By

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11/ Alternatively, to the extent the Commission does not believe that PG&E's specific adder should be adopted, it should at least not prohibit a non-zero integration adder so that the IOUs can take into account potential integration costs associated with bids on a case-by-case basis.

12/ Proposed Decision at 43-44.

13/ *Ibid.*

14/ Proposed Decision at 20.

rejecting PAV, the Proposed Decision would have PG&E implement these preferences much less clearly and transparently. Both PG&E's customers and RPS bidders are better served by having PG&E use PAV in its evaluation of bids.

To improve the clarity and transparency of the PAV methodology, PG&E is appending to these comments as Attachment 1 a more detailed discussion of the PAV methodology. PG&E proposes to use Attachment 1 as a substitute for the PAV discussion found in the Draft 2012 RPS Solicitation Protocol. For the 2012 RPS RFO, PAV adjustments would include the following components: Location, RPS Portfolio Need, Energy Firmness, Contract Term Length (Tenor), and Curtailment. The descriptions of these adjustments in Attachment 1 specify why these adjustments are not duplicative of the net market value calculation approved by the Proposed Decision. PG&E's initial PAV methodology also included an adjustment for integration cost, but PG&E now proposes to remove integration from the RPS RFO PAV methodology given that the Proposed Decision would make those integration costs a standard variable in the net market value calculation. Attachment 1 provides the right balance between specificity and transparency for bidders while keeping sensitive commercial information available only to PG&E's Procurement Review Group (PRG), the Independent Evaluator (IE), and others focused on insuring a fair and transparent solicitation that yields efficient and cost-effective outcomes for PG&E's customers.

With the greater clarity and transparency provided in Attachment 1, the Commission should determine that the PAV methodology is consistent with its LCBF decisions and that PG&E is faithfully implementing the LCBF policy goals. At the very least, the Commission should allow the provisional use of the PAV methodology in the 2012 RPS RFO process, so that the PAV results may be used by the IE and the PRG as a tool in informing themselves about the fairness and cost-effectiveness of PG&E's solicitation.

C. The Decision Should Not Require Phase II Interconnection Studies Prior to PPA Execution.

The Proposed Decision includes two elements that are meant to ensure project viability and to avoid IOU customers bearing more expensive transmission upgrade costs associated with executed RPS PPA than the counterparties had anticipated at the time of PPA execution. The first element is a requirement that RPS developers conclude a Phase II interconnection study, or its equivalent if outside the CAISO, prior to being eligible to execute a PPA with the IOUs.[15/] In general, a Phase II study provides more precise information regarding the ultimate expected cost of interconnection that will be ultimately borne by customers than a Phase I study, and thus may result in a change in total value of a PPA such that an IOU would find that it no longer merits selection when compared with other bids. The second element is a provision that would require the IOUs to include a transmission upgrade cost cap in the form PPA that will provide an IOU with a unilateral termination right should transmission upgrade costs eventually exceed the cap.[16/] The counterparty would have a "buydown right" that would allow it to avoid such a termination if it offers to pay any excess transmission upgrade costs above the cap without seeking reimbursement of those costs from California electricity customers later (as is normally allowed for transmission upgrades).[17/]

In general, PG&E supports and shares the Commission's goal to ensure that RPS procurement results in the highest viability projects with the greatest overall value for PG&E's

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15/ Proposed Decision at 41.

16/ *Id.* at 31.

17/ *Ibid.*

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customers. However, the IOUs have a number of means to increase and ensure the viability of the bids that they accept other than requiring an expensive and time-consuming Phase II interconnection study. For example, an IOU can negotiate terms for the posting of security and limit delays permitted under a PPA due to transmission upgrades to discourage developers from proposing projects that are not viable. Additionally, the transmission cost upgrade cap will serve to limit the potential cost of unexpected transmission upgrade costs and allows the potential for such costs to be placed on the developer rather than IOU customers. Thus, the Phase II study requirement serves policy goals that can already be achieved by other available contractual mechanisms.

Although it offers little incremental benefit, the Phase II study requirement will create significant competitive and cost impacts that may not have been intended. First, requiring developers to post substantial Phase II study deposits prior to securing a PPA with an LSE will likely complicate project financing for most developers. Only developers with a high risk tolerance and relatively large amount of cash reserves would remain in the bidder pool given the high cost of the interconnection study process and the uncertainty regarding both the outcome of that process and the eventual execution of a PPA that would result in an adequate return for the project. A smaller bidder pool, in turn, will generally increase RPS procurement prices based upon the fundamental economic concepts of supply and demand. Moreover, the developers willing to remain in the bidder pool will need to price their bids higher in order to compensate them for the higher development risk they are taking on their own balance sheets by having to proceed with the interconnection process in the absence of a PPA. In combination, PG&E expects that the Phase II study requirement will limit the pool of potential bidders and increase the average price of RPS procurement.

Second, the Phase II study requirement is not necessary to ensure projects can meet their contractual online dates. The issue of timing interconnection studies with bidding processes is particularly troublesome when, as with PG&E's 2012 RPS RFO, deliveries are not generally needed until many years after the PPAs will be executed. It may be unreasonably costly and complicated from an interconnection planning standpoint to complete Phase II interconnection studies for a project that will not be built or interconnected for many years, at which time the grid may be very different.[18/]

Finally, the Phase II requirement is not necessary to protect ratepayers against uncertain transmission costs. Maintaining the transmission upgrade cost cap while removing the Phase II study requirement maintains the laudable policy objective of these elements while avoiding the competitive and cost impacts described above. In this case, a larger pool of bidders (both those with and without completed Phase II studies) would be eligible to execute PPAs with IOUs, but those PPAs would include termination rights to cap the eventual total cost of the procurement. The bidder would thereby have the choice to take the risk of transmission cost overruns, which could lead to termination, or, if it is able to self-finance the interconnection process, to complete the Phase II study prior to execution of the PPA and reduce significantly the chance that it will face termination for such overruns. This will allow greater participation by developers with varying business models, and will tend to drive down the overall cost of RPS procurement.

18/ A related issue that would arise should the Commission maintain the Phase II requirement is how to address a situation in which a developer with a PPA has to re-initiate the study process after it has received a Phase II study and has executed a PPA. Would the Proposed Decision require that the PPA be terminated in that circumstance, even if the project remains viable, cost-competitive, and needed to meet RPS compliance? If so, the Proposed Decision could introduce considerable risk and uncertainty in the RPS compliance planning process, increasing total RPS Program costs even further by requiring IOUs to maintain larger compliance margins.

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D. Any Expiration Period for Shortlists Should Begin to Run At the Time of Shortlist Approval Rather Than Submission.

The Proposed Decision would require that the shortlist for an RPS RFO expire within twelve months of submission of the final shortlists.[19/] Any shortlisted bid that did not result in an executed PPA by that expiration date would have to be re-bid in the next solicitation before it could be re-considered.[20/]

PG&E does not believe the 12 month requirement is necessary to incent parties to negotiate PPAs in a timely manner. However, if the Commission decides to retain the expiration requirement, it should at least modify the language in the Proposed Decision to have the twelve month period begin to run when the Commission's adoption of the final IOU shortlists becomes final and non-appealable.[21/] Additionally, a shortlist should only expire where the Commission has approved and definitively set the start date for another RPS RFO within six months of the expiration to ensure that competitive and time-sensitive deals that could not be completed within the expiration period do not have to wait years for the next procurement opportunity.

E. The IE Should Not Opine on Whether IOUs Acted in "Good Faith."

The Proposed Decision would require the IE to determine whether an IOU had negotiated in "good faith" with shortlisted bidders prior to the expiration of the shortlist.[22/] While PG&E has no opposition to the IE performing his or her traditional role in evaluating the fairness of

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19/ Proposed Decision at 89 (OP 9).

20/ *Ibid.*

21/ It is worth noting that PG&E has not yet received a final disposition letter approving its revised and final 2011 RPS RFO shortlist, submitted in February 2012, meaning that under the rule proposed here, 2011 RPS RFO bids would expire just a few months after the shortlist is formally approved and made effective. Notwithstanding formal CPUC disposition of the shortlist advice filing, PG&E filed advice letters seeking Commission approval of several PPAs resulting from the 2011 RPS RFO in September 2012.

22/ Proposed Decision at 33.

negotiations, the Commission should neither imply that IOUs have to execute PPAs on the shortlist to meet a "good faith" standard, nor should it require the IE to opine on whether IOUs showed "good faith." The concept of "good faith" negotiations is a commercial term of art that has been the subject of considerable interpretation by courts. Even if PG&E had an obligation to negotiate in good faith with shortlisted bidders to execute a PPA, which it does not, whether PG&E met such an obligation is a question of law rather than a factual or procedural issue that should be the subject of an IE's assessment. PG&E's RPS shortlist is likely to be multiples of the volumes it expects to execute, and PG&E's RFO protocol is clear that a position on the shortlist is no guarantee of a PPA. Because a finding regarding "good faith" is beyond the scope of an IE's commission and unnecessary to determine the fairness of a solicitation, the Proposed Decision should be amended to remove the reference to the phrase "good faith."

F. The Commission, Rather Than the IOUs, Should Monitor the Total Capacity from Imperial Valley under Contract.

The Proposed Decision would require that the IOUs do not collectively assume less than 1,400 megawatts ("MW") of import capacity from the IID balancing authority into CAISO.[23/] PG&E interprets this requirement to allow it to continue assuming no constraint on import capacity from the IID balancing authority into CAISO for purposes of assessing resource adequacy value in the offer evaluation process.[24/] To avoid administrative and legal complications, the Commission should not require the IOUs to coordinate bid evaluations regarding IID-based bids, but rather the Commission itself is in the best position to monitor the collective procurement from IID and should modify its order once the designated 1,400 MW

23/ Proposed Decision at 16-18.

24/ PG&E notes that nothing in the Proposed Decision would limit IOUs' ability to incorporate into executed PPAs with Imperial Valley projects certain terms that may require the seller to ensure that its project does, in fact, provide Resource Adequacy value for all or part of the term.

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Maximum Import Capacity ("MIC") is fully under contract.

G. The Commission Should Not Require PG&E and SDG&E to Submit Their Shortlists Concurrently Or on a Specific Date.

The Proposed Decision would adopt a schedule for the 2012 RPS solicitations that would require both PG&E and SDG&E to concurrently submit their shortlists to the Commission for approval on the 154th day following issuance of the decision adopting the 2012 RPS Plans.[25/] Separately, Commissioner Ferron has issued a ruling that proposes new standards of review for IOU shortlists, including requiring that the shortlists be adopted through a more rigorous Tier 3 Advice Letter process that results in a formal Commission resolution rather than the historical Tier 2 process.[26/] Given the trend toward greater emphasis and scrutiny of the shortlists, and the uncertainty regarding how many bids the IOUs will receive and need to evaluate, the Commission should allow the IOUs discretion and flexibility regarding the timing to file their shortlists.

In the past, the Commission has allowed IOUs to require bidders to agree to exclusivity in negotiations only after the IOUs notify bidders of their shortlists. In a seller's market, it was important to require the IOUs to finalize and provide notice of their shortlists simultaneously to avoid a race to "lock up" scarce bids by rushing the shortlisting process. More recently, market conditions have changed, and PG&E is less concerned about the need to ensure exclusivity with its bidders at the time that it submits it shortlist. In fact, given the proposal to establish more rigorous Commission review of the shortlists, PG&E requests authority to amend its 2012 RPS Solicitation Protocol when it files its conformed 2012 RPS Plan to require exclusivity only after

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25/ Proposed Decision at 75.

26/ Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals and Establishing a Schedule for Comments on Proposals, R.11-05-005, issued October 5, 2012, at 9-10.

the Commission has approved its shortlist.

For similar reasons, it is less important today than in the past that the IOUs submit their shortlists at the same time. Given the maturation of the renewables market that has led to RPS RFO offers significantly in excess of need, the Commission need not be concerned about IOUs racing to "lock up" bids. A more pressing concern is the need for adequate time to thoroughly and carefully evaluate the bids received to ensure that the shortlist represents the least-cost, best-fit offers. The Commission should not set an arbitrary date for the shortlist submission, but rather should grant the IOUs flexibility to provide bidders notice of the shortlist and to file their shortlists anytime within four months of the close of bidding.

H. Final RPS Plans Should Be Filed 14 Days From the Issuance of a Final Decision, Not Including Holidays.

The Proposed Decision includes a solicitation schedule that would require filing of the final, conformed RPS Procurement Plans within 14 days of the Commission's final decision conditionally adopting the Plans, but it is internally inconsistent regarding whether that time is measured from the effectiveness of the final decision or its issuance/mailing.[27/] The Proposed Decision should be modified at page 2 to measure the 14 days from issuance/mailing of the Decision and the counting of that time should exclude the official state holidays on November 11, 22, and 23, as applicable.

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27/ *Compare* Proposed Decision at 75 (mailing) *with* 2 (effective date).

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III. CONCLUSION

For the reasons stated above, PG&E requests that the Commission issue a decision that adopts the proposals and methodologies set forth in these comments and revises the findings, conclusions, and orders as shown in Attachment 2 to these comments.

Respectfully Submitted,

CHARLES R. MIDDLEKAUFF
M. GRADY MATHAI-JACKSON

By: */s/ M. Grady Mathai-Jackson*
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-3744
Facsimile: (415) 972-5952
E-Mail: mgml@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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Attachment 1: Revised PAV Methodology Description

Portfolio-adjusted Value ("PAV") is intended to represent the value of a resource or Offer in the context of PG&E's portfolio. This approach contrasts with Market Value, which is intended to represent the value of a resource or Offer regardless of PG&E's portfolio. The calculation of PAV thereby makes explicit and systematic PG&E's preferences for project location, delivery start dates, and contract term lengths (tenor). PAV also makes explicit and systematic the reduction in value to PG&E's portfolio associated with the uncertainty in the firmness of generation from an offer and the increase in value to PG&E's portfolio of flexibility in scheduling the generation from an offer. To calculate PAV, adjustments are made to PG&E's Market Value calculations, components, and/or resulting values.

As PG&E's portfolio changes, different adjustments may be appropriate. Thus, the description of PAV in this document will apply for PG&E's 2012 RPS RFO only and is not intended to apply to future RPS solicitations by PG&E or other PG&E solicitations. For the 2012 RPS RFO, PAV adjustments include the following components: Location, RPS Portfolio Need, Energy Firmness, Contract Term Length (Tenor), and Curtailment.

1. Location

PG&E has a preference for projects in its service territory. This preference is influenced by constraints (either in the marketplace or imposed on PG&E by regulatory agencies) that may limit the amount of capacity in SP15 that PG&E can count toward its RA requirement. Capacity located closer to PG&E's load is likely to deliver energy that has more value for PG&E's bundled electric portfolio, even when market forward prices indicate that energy delivered farther away has greater Market Value. The long-term need for new resources in PG&E's service territory is also more likely to be mitigated by a new resource in NP15 than a new resource located in SP15. The calculation of PAV effectuates this by adjusting the value of energy and capacity for offers from resources in SP15.

The PAV Energy Benefit for offers from resources in SP15 is calculated using the minimum of the SP15 energy forward price and the NP15 energy forward price, for each period the value of energy is calculated. This adjustment is not intended to adjust for congestion—that is accounted for in the calculation of Net Market Value in the Locational Marginal Price Aggregation Multipliers. This adjustment is intended to account for the relative value, to PG&E's portfolio, of energy that may be used to serve PG&E's bundled customer load. This adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's calculation of Energy Value in Net Market Value represents an offer's value of energy to any wholesale market participant, including investor-owned utilities in southern California and purely financial traders, the locational adjustment described here is specific to PG&E's portfolio and would not be made by investor-owned utilities in southern California, financial traders, and wholesale market participants in general (although the locational adjustment described here might be made by other load-serving entities with load heavily concentrated in northern and central California).

The PAV Capacity Benefit for offers from resources in SP15 is calculated using a short-run avoided cost of capacity rather than a long-run avoided cost of capacity, even when the PAV Capacity Benefit for offers from resources in NP15 is calculated using a long-run avoided cost of capacity. This adjustment is intended to account for the relative value, to PG&E's portfolio, of capacity that may be used to meet future resource adequacy requirements to serve PG&E's bundled electric customers. This adjustment is not duplicative of the Capacity Value component of Net Market Value. Whereas PG&E's calculation of Capacity Value in Net Market Value represents an offer's value of capacity to any wholesale market participant, including investor-owned utilities in southern California and purely financial traders, the locational adjustment described here is specific to PG&E's portfolio and would not be made by investor-owned utilities in southern California, financial traders, and wholesale market participants in general (although the locational adjustment described here might be made by other load-serving entities with load heavily concentrated in northern and central California).

As a consequence of these adjustments to the value of energy and capacity, offers from resources in NP15 will tend to have higher PAV and rank better than equivalent offers from resources in SP15.

2. RPS Portfolio Need

PG&E has a preference for offers with deliveries beginning in 2019-2020. [1/] PG&E will consider how an offer contributes to PG&E's overall portfolio need for RPS energy. For each delivery year in which PG&E's portfolio (augmented by the offer) is projected to be short RPS-eligible energy, the Energy Benefit of that offer's RPS-eligible energy will be increased using PG&E's forward price curve for Renewable Energy Credits (RECs). However, for each delivery year in which PG&E's portfolio (augmented by the offer) is projected to be long RPS-eligible energy, no additional value will be attributed to the offer's RPS-eligible energy; in other words, that RPS-eligible energy will be valued using an energy price curve for non-renewable energy. This RPS portfolio need adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's Net Market Value calculation reflects the value of generic energy in the marketplace, the RPS portfolio need adjustment described here reflects the incremental value of RPS-eligible energy to PG&E's portfolio in those years, and only those years, when the energy actually is projected to be needed to meet the portfolio's RPS requirement.

Thus, offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV and rank better than equivalent offers that deliver RPS energy in periods when PG&E's portfolio does not need RPS energy.

3. Energy Firmness

PG&E's Net Market Value calculation of Energy Value uses energy forward price curves that are associated with firm energy. Offers in the RPS RFO are typically not for firm energy. To value the energy benefit for an offer from a resource that has uncertainty in the minute-by-minute production of energy, a risk-adjusted multiplier is used in calculating PAV. PAV is calculated as the product of an offer's Energy Benefit (as calculated in the Energy Value

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1/ PG&E Draft 2012 RPS Plan – May 2012 Draft, Appendix 6 (2012 Solicitation Protocol), at 12.

component of Net Market Value and then adjusted by the locational adjustment and RPS portfolio need adjustment described above) and the PAV risk-adjusted multiplier for that offer. The PAV risk-adjusted multiplier takes on values between 0.8 and 1.0. A multiplier of 1.0 represents an offer's Energy Benefit is the same as if the offer were to provide firm energy. A multiplier of 0.8 represents substantial reduction in an offer's Energy Benefit because of the offer's significant uncertainty in energy production from its resource. The multiplier for an offer from a solar thermal resource will typically be higher than the multiplier for an offer from a wind resource or a solar PV resource. An offer for a solar thermal resource with storage will typically have a higher multiplier than a solar thermal resource without storage. The particular PAV risk-adjusted multiplier applied to an offer will be a function of the relative firmness of the offer's energy and not simply a function of the renewable technology being offered.

The energy firmness adjustment itself will not result in any PAV increase or better ranking for offers providing dispatchability. For offers providing dispatchability, PG&E will either: (1) use option-based approaches to calculate the Energy Value component of Net Market Value, and/or (2) calculate PAV using the curtailment adjustment described below. Nonetheless, offers providing dispatchability will have higher PAV and rank better than equivalent offers that do not provide dispatchability.

The energy firmness adjustment is not duplicative of the Energy Value component of Net Market Value. Whereas PG&E's Net Market Value calculation reflects the value of firm energy in the marketplace, the energy firmness adjustment described here reflects PG&E's assessment of the reduction in offer value that results from measuring and managing a position with uncertainty in energy production. For the same particular offer, other wholesale market participants might assess lower or higher reductions in offer value, resulting from each wholesale market participant's different portfolio positions and different capabilities, opportunities, and constraints for wholesale market activities.

The energy firmness adjustment is also not duplicative of any integration cost adder that might be used in PG&E's 2012 RPS RFO. The energy firmness adjustment is strictly in the context of PG&E's portfolio. In contrast, an integration cost adder is in the context of the system: "[T]he function of this [integration cost] adder would be to estimate the cost to ratepayers for the real time balancing of the transmission system from instability caused by unexpected fluctuations in generation or load caused by the [offer's] project."[2/] The PG&E portfolio perspective and the physical transmission system perspective are two distinct and separate perspectives.

Thus, offers that deliver RPS energy with greater firmness will have higher PAV and rank better than equivalent offers that deliver RPS energy with less firmness.

4. Contract Term Length (Tenor)

PG&E prefers long-term transactions to match the portfolio's long-term RPS need, and so is

2/ Proposed Decision at 26.

seeking contracts with delivery periods 10 years or greater.[3/] A countervailing consideration is that longer-term transactions may pose greater project risk because of uncertainty in market conditions. PG&E has therefore expressed a preference for offers with delivery periods of 10 to 15 years rather than delivery periods lasting 20 years or more.[4/]

In calculating PAV, the value of an offer is adjusted for the length of the delivery period being offered (i.e., the "contract term length" or "tenor") using an adder. The adder takes on values between -10 and +10 dollars per MWh. Provided that an offer has contract term length at least 10 years, the shorter is the contract term length, the higher is the value of the adder, and consequently the higher is the PAV of the offer and the better is the ranking of the offer.

The contract term length adjustment is not duplicative of the Net Market Value calculation. PG&E's Net Market Value calculation is not directly affected by contract term length. Net Market Value is determined by the year-by-year differences between an offer's contract price (including the time-of-delivery factors) and the forward curves for energy and capacity. The present value of these year-by-year differences matter, but contract term length itself does not matter. PG&E's Net Market Value calculation is an expected value calculation. In contrast, the PAV calculation quantifies, in the context of PG&E's portfolio, how contract term length affects the riskiness of an offer.

Thus, offers with shorter contract term lengths (but contract term length at least 10 years) will have higher PAV and rank better than equivalent offers with longer contract term lengths.

5. Curtailment

PG&E prefers offers that provide PG&E flexibility in scheduling a resource's generation. PG&E values the flexibility associated with Buyer Curtailment. The draft 2012 Form RPS PPA requires a Seller to offer at least 250 hours of Buyer Curtailment, for which the Seller will be compensated. The PPA also allows a Seller to offer more hours of curtailment, and to specify the price the Seller would be paid for energy deemed delivered in those hours.[5/]

For offers providing additional hours of Buyer Curtailment beyond the 250 required hours, PG&E's Net Market Value calculation of Energy Value will include, for the additional hours of Buyer Curtailment, the expected value of the difference between the (presumably negative) wholesale market spot price avoided when Buyer Curtailment occurs and the contractual payments to the Seller when Buyer Curtailment occurs. This expected value is anticipated to be realized by any wholesale market participant and is not specific to the particular composition or positions of PG&E's portfolio or PG&E's particular capabilities, opportunities, and constraints for wholesale market activities.

3/ PG&E Draft 2012 RPS Plan – May 2012 Draft, Appendix 6 (2012 Solicitation Protocol), at 12.

4/ PG&E Draft 2012 RPS Plan – May 2012 Draft, at 64.

5/ PG&E Draft 2012 RPS Plan – May 2012 Draft, at 63.

However, additional hours of Buyer Curtailment provide incremental value to PG&E's portfolio, above and beyond the expected value included in Net Market Value. Such incremental value may include reducing the portfolio's costs for imbalance energy charges from the CAISO, avoiding involuntary curtailment orders issued by the CAISO to PG&E, avoiding extreme volatility in spot market prices for ancillary services, and similar benefits associated with managing the portfolio. The PAV curtailment adjustment is the estimated value of these incremental benefits to PG&E's portfolio, minus the estimated value of contractual payments to the Seller for any incremental curtailment situations not already included in the Net Market Value calculation. Defined in this way, the PAV curtailment adjustment is therefore not duplicative of PG&E's calculation of Net Market Value.

The PAV curtailment adjustment is also not duplicative of any integration cost adder that might be used in PG&E's 2012 RPS RFO. The curtailment adjustment is strictly in the context of PG&E's portfolio. In contrast, an integration cost adder is in the context of the system. The PG&E portfolio perspective and the physical transmission system perspective are two distinct and separate perspectives.

The PAV curtailment adjustment is also not duplicative of the PAV energy firmness adjustment. The curtailment adjustment reflects a flexibility or dispatchability (emanating from hours of Buyer Curtailment) that is a quality superior to must-take firm energy, whereas the energy firmness adjustment reflects uncertain generation that is typically inferior to must-take firm energy and at best is the same quality as must-take firm energy.

Thus, offers that provide greater amounts of additional hours of Buyer Curtailment with lower contractual payments to the Seller will have higher PAV and rank better than equivalent offers that provide lesser amounts of additional hours of Buyer Curtailment with higher contractual payments to the Seller.

<u>**Attachment 2: Proposed Revisions to Findings, Conclusions, and Orders**</u>

Findings of Fact

1. SDG&E has approximately 3,300 GWh under contract from projects that will be facilitated by the Sunrise Powerlink Transmission Project.

2. SDG&E continues to consider contracting with projects located in the Imperial Valley region.

3. The Independent Evaluator's report captures the robustness of the responses to PG&E's 2009 and 2011 RPS solicitations in the Imperial Valley region.

4. There has been a lack of interest in special Imperial Valley Bidder's conferences in the past and the event has created confusion.

5. If the utilities each assume a MIC of 1,400 MW for projects in the Imperial Valley area, when in reality, that MIC must be shared among all requesting load-serving entities, utilities are likely to over-value imports from IID.

6. Requiring the utilities to ~~each use a 1,400 MW MIC value~~<u>assume no import constraints exist</u> for projects in the IID ~~area~~<u>balancing authority area once executed PPAs exceed the 1,400 MW MIC value</u> may result in equity concerns regarding bids at other interties.

7. Solicitation preferences are consistent with the RPS Program's policies and rules.

8. The goal of the proposal in the April 5, 2012 ACR to standardize the variables considered in the NMV calculation was to increase transparency in the LCBF evaluation process and streamline review of bid solicitations and contracts by establishing a standardized set of values and costs. Standardization will better promote comparison between the utilities.

9. The addition of new variables to the NMV calculation could potentially add to the robustness of the calculation but sufficient evidence does not presently exist for determining whether these additional variables would be more appropriately included as part of the NMV calculation or as a separate aspect of the utilities' LCBF evaluations.

10. ~~Deferring the adoption of a non-zero~~<u>Adopting a $7.50 ($2008)</u> integration cost<u> adder</u> is reasonable until ~~developed in a public forum. We are currently assessing renewable integration needs and costs in another proceeding, R.12-03-014.~~<u>more specific integration cost information is available.</u>

11. The pro forma agreements are negotiable, except for the "standard terms and conditions" and serve as the starting point for negotiating a final agreement between the seller and utility.

12. The contract term regarding a transmission upgrade cost cap and the related buy-down provision serves to limit the total RPS procurement costs to ratepayers by linking contract termination rights to limits on transmission network upgrade costs.

13. The April 5, 2012 ACR presented a proposal that bids shortlisted by the utilities would have to be executed, if at all, within 12 months from the date that the utility submits its final shortlist to the Commission. The benefits of being able to compare a contract's value and price to current solicitation data outweighs the concerns regarding adopting a limited contract negotiation period.

14. The proposal presented in the April 5, 2012 ACR for the shortlist to expire after 12 months ensures consistency by prohibiting the utility to then execute a bilateral contract for the same project until a subsequent solicitation is initiated. The project is permitted to bid into any subsequent RPS solicitation.

15. Consistent with D.11-04-030, PG&E and SDG&E must accommodate bids that are energy-only or fully deliverable in their 2012 solicitation protocols.

16. LSA does not provide adequate evidence or argument that PG&E's or SCE's proposed new Time of Delivery factors are flawed.

17. The proposals in the April 5, 2012 ACR to create two shortlists sought to provide the most current and accurate cost information at key decision points in the RPS procurement process so as to minimize ratepayer costs and maximize value to the ratepayer.

18. In the past, the Commission has directed utilities to set the minimum capacity for projects bidding into the RPS Program's solicitation based on the R.11-05-005 availability of options for contracting through other programs, such as the Feed-in-Tariff program, that target smaller generation.

19. PG&E's Portfolio-Adjusted Value methodology ~~lacks sufficient clarity and may~~quantitatively expresses PG&E's preferences for project location, delivery start dates, and contract term lengths (tenor); is not duplicative of include variables already captured in its net market value calculation~~ and LCBF.~~; and is sufficiently clear to enable bidders to understand how their bids would be affected.

20. Projects bidding into the 2012 RPS solicitation will most likely propose contracts commencing after the Production Tax Credit and the Investment Tax Credit expire.

21. The Commission seeks to standardize contract terms and program provisions among procurement programs for the three large investor-owned utilities when possible.

22. SCE and SDG&E currently apply the credit rating requirements that PG&E now proposes in its 2012 RPS Procurement Plan.

23. During the time period covered by the 2012 RPS Procurement Plans, SCE can address any unmet RPS compliance needs through smaller-scale renewable facilities that are less than 20 MW in size.

24. Currently, a utility must use the Tier 3 Advice Letter process when seeking Commission approval of a contract for the sale of RPS products.

25. Tier 2 Advice Letters may become effective after review by Energy Division Staff rather than after a vote by the full Commission.

26. In D.12-11-052, the Commission found it would not determine the portfolio content category of RPS resources until the utility submits an RPS compliance report and supporting information, as necessary, the Commission to determine the proper portfolio content categorization of the actual procurement and to make a compliance determination. This process does not happen at the time the Commission approves contracts.

27. The intent of the proposal in the April 5, 2012 ACR to replace the annual solicitation cycle with a two year cycle was to streamline the procurement process without sacrificing the transparency provided by the filing of annual procurement plans.

28. In directing the use of the PVC, the Commission noted that the PVC is an indicative rather than predictive tool and that the utilities remain responsible for the recommendations they make regarding projects necessary to meet their RPS Program requirements.

29. Further evidence is needed to understand the potential benefits of streamlining the contract amendment process relied upon by the Commission.

30. Regarding confidentiality of information related to RPS contracts, increased transparency is sought but it is unclear what additional information should be disclosed to the public.

31. The proposal in the April 5, 2012 ACR to require two, instead of one, Independent Evaluator reports sought to provide an early review of the procurement process of each utility.

32. Modifications are needed to the proposal in the April 5, 2012 ACR to utilize the RPS procurement process to minimize transmission costs. The proposal was to limit the amount of new generation procured in certain areas to ensure that costly network upgrades would not be triggered.

33. Pursuant to § 365.1 and D.11-01-026, ESPs are required to file annual procurement plans.

Conclusions of Law

1. The Commission is committed to continuing to monitor renewable procurement activities in Imperial Valley but declines the requests for additional oversight mechanisms based on, among other things, the continued robust procurement in the area.

2. A special Imperial Valley Bidder's conference should be optional for the utilities due to the lack of interest.

3. PG&E, SCE and SDG&E should ~~not each assume a 1,400 MW MIC from Imperial Valley because a number of complications could result from such a requirement, such as utilities are likely to over-value imports from IID and equity concerns could arise regarding bids at other interties.~~assume for purposes of bid evaluation in the RPS RFOs that no importation limits exist for purposes of Resource Adequacy between Imperial Valley and the CAISO, and the Commission should monitor total procurement to modify this assumption once the IOUs have collectively procured or are negotiating to procure 1,400 MW from Imperial Valley.

4. Consistent with PG&E's explanation, no preferences should be given to CAISO-interconnected projects or to projects otherwise interconnected.

5. It is reasonable for the utilities to solicit offers based on various preferences.

6. The proposal presented in the April 5, 2012 ACR to standardize the variables to be included in the net market value (NMV) calculation is reasonable as it is consistent with past Commission decisions to promote transparency, further streamline the contracting process, and increase standardization across the utilities' LCBF methodologies.

7. The NMV calculation is a part of the utilities' LCBF methodologies. We make no determination on the value calculation of those NMV variables, except as noted in sections 4.2.3 (Integration Cost Adder) and 4.4.1 (Transmission Study Status Impact on Bid Valuation and Shortlist).

8. Based on the existing evidence, it is not reasonable to adopt additional variables to the NMV calculation.

9. It is reasonable to ~~preserve the zero value~~adopt a $7.50 ($2008) integration cost adder in this proceeding~~ because additional evidence should be required to make an alternative determination~~.

10. It is reasonable to authorize utilities to incorporate a provision into their pro forma agreements for use of a transmission upgrade cost cap and a related buy-down provision to limit the total RPS procurement costs to ratepayers.

11. It is reasonable to require the shortlist to expire 12 months after approval by the Commission because the benefits of being able to compare a contract's value and price to current solicitation data outweighs the concerns regarding the constraints imposed by a limited negotiation period.

12. Because utilities are permitted to receive two types of bids (energy-only or fully deliverable), we find it reasonable for the utilities to apply different sets of Time of Delivery factors to these two types of bids.

13. The goals of the April 5, 2012 ACR to rely on the most current and accurate cost information at key decision points in the RPS procurement process and to maximize value to the ratepayer are achieved by requiring bids to obtain a minimum of a completed CAISO GIP Phase I (or equivalent) study to bid into the solicitation. These goals are ~~further achieved~~not significantly furthered by requiring projects to have the minimum of a completed CAISO GIP Phase II (or equivalent) study in order for a contract to be executed.

14. The minimum size of projects participating in RPS Program solicitations should be increased to greater than three MW based on the existing contracting options for projects with a nameplate capacity of three MW under in the Feed-in Tariff program and other programs for small renewable generators.

15. PG&E should ~~remove~~be allowed to use its Portfolio-Adjusted Value methodology ~~from its solicitation protocol as the methodology is not consistent with Commission decisions on LCBF evaluation of projects and previous decisions approving RPS Procurement Plans~~as the methodology is sufficiently clear, enabling bidders to better tailor their bids to PG&E's needs, thereby enhancing the efficiency and cost-effectiveness of PG&E's procurement.

16. The Production Tax Credit and the Investment Tax Credit term in the pro forma agreement should be removed as it is likely that these federal tax credits will expire before contracts resulting from the 2012 RPS solicitation are executed.

17. PG&E's request to relax the credit rating requirements for financial institutions seeking to provide letters of credit for contracts resulting from the utility's RPS solicitations is reasonable because SCE and SDG&E currently apply these same credit rating requirements, there has been changes in the global economic situation, and PG&E continues to rely on credit-worthy institutions to provide letters of credit.

18. SCE's proposal to not hold a 2012 RPS solicitation is reasonable based on the explanation that, during the time period covered by the 2012 RPS Procurement Plans, SCE will address any unmet RPS compliance needs through smaller-scale renewable facilities that are less than 20 MW in size.

19. SCE's proposal that it will consider offers for bilateral contracts during the time period covered by the 2012 RPS Procurement Plans is not reasonable because price reasonableness of such contracts is evaluated by comparison to the annual solicitation, which SCE will not hold.

20. Each utility remains responsible for meeting its RPS Program procurement requirements.

21. Because it is unclear whether the Tier 2 Advice Letter process will increase the utility's efficient management of its portfolio while maintaining sufficient ratepayer protections, the proposal for an expedited regulatory review process for excess REC and energy sales through the Tier 2 Advice Letter process should not be approved.

22. Consistent with D.11-12-052, the Commission's recent decision implementing the statutory amendments in Senate Bill 2 1X pertaining to portfolio content categories set forth in § 399.16(b)(1), the proposal that the Commission determine the portfolio content category of resources prior to the contract becoming effective should not be approved.

23. While the proposal to hold solicitations every two years, rather than annually, holds promise in terms of reducing the administrative burden resulting from annual filings, it should not be adopted at this time because it leaves a number of details undeveloped.

24. Based on the existing evidence, no changes to the PVC should be adopted and utilities should continue to use the PVC as an indicative tool and as one criterion in a utility's bid evaluation methodology.

25. Because further evidence is needed to understand the potential benefits of any efforts to streamline the process relied upon by the Commission to approve contract amendments, recommendations to change this process should not be approved at this time.

26. Because more analysis is required to comprehensively address confidentiality issues, especially with regards to changes appropriate for the RPS program framework under Senate Bill 2 1X, no changes should be made to the Commission's confidentiality rules at this time.

27. Because more analysis is needed to determine the benefits, if any, of requiring two, instead of one, Independent Evaluator reports, no modifications to the existing process should be adopted at this time.

28. Because more analysis is needed, the proposal presented in the April 5, 2012 ACR regarding minimizing transmission upgrade costs should not be addressed at this time.

29. The motion filed on April 17, 2012 by Shell Energy North America, (US), L.P and the Direct Access Customer Coalition for reconsideration of Assigned Commissioner's April 5, 2012 ruling should be denied.

ORDER

IT IS ORDERED that:

1. Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1), the 2012 Renewables Portfolio Standard Procurement Plans, including the related Solicitation Protocols, filed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are conditionally accepted, as modified herein.

2. Pacific Gas and Electric Company, Southern California Electric Company, and San Diego Gas & Electric Company shall file final Renewables Portfolio Standard (RPS) Procurement Plans with the Commission to initiate the RPS solicitation process within 14 days of the ~~effective date~~issuance of this decision (excluding November 11, 22, and 23, if applicable) pursuant to the RPS solicitation schedule adopted herein.

3. The Commission's Energy Division Staff shall continue to monitor development of projects under the Renewables Portfolio Standard (RPS) Program in the Imperial Valley according to the parameters set forth in Appendix A of Decision 09-06-018. In addition, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are directed to provide a specific assessment of the offers and contracted projects in the Imperial Valley region in future RPS Procurement Plans filed with the Commission pursuant to Pub. Util. Code § 399.11 *et seq.* until directed otherwise by the Commission.

4. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)~~, collectively,~~ should ~~not~~ assume ~~a total maximum import capability of less than 1,400 megawatts for imports from projects within the Imperial Irrigation District Balancing Authority Area as part of the evaluation of projects and bids within the 2012 Renewables Portfolio Standard (RPS) solicitation or future RPS solicitations. If PG&E, SCE, or SDG&E, nevertheless, assigns zero or near zero resource adequacy value to any project located in the Imperial Irrigation District Balancing Authority Area that bids in the 2012 RPS solicitation or future solicitations, that utility must present clear and convincing evidence why it did so as part of each request seeking Commission approval of any contract resulting from that solicitation. These directives~~for purposes of bid evaluation in the RPS RFOs that no importation limits exist for purposes of Resource Adequacy between Imperial Valley and the CAISO. The Commission will monitor total procurement in order to modify this assumption once the IOUs have collectively procured or are negotiating to procure 1,400 MW from Imperial Valley. This directive shall apply to PG&E, SCE, and SDG&E in any subsequent RPS Procurement Plans unless otherwise directed by the Commission.

5. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) are authorized to include varying preferences, including, but not limited to, project location, delivery start dates, contract term lengths, and specific portfolio content categories. This authorization applies to PG&E and SDG&E in any subsequent RPS Procurement Plans unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, this authorization shall apply to any subsequent SCE RPS solicitations unless otherwise directed by the Commission.

6. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific R.11-05-005 Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall modify their Least Cost, Best Fit methodologies to reflect the Net Market Valuation (NMV) calculation set forth below. We authorize the Commission's Energy Division Staff to propose modifications to the inputs to the NMV calculation through the Commission Resolution process. This methodology shall be employed by PG&E, Southern California Edison Company, and SDG&E in any subsequent RPS Procurement Plans unless otherwise directed by the Commission.

Net Market Value: $R = (E + C) - (P + T + G + I)$
Adjusted Net Market Value: $A = R + S$
Where:
R = Net Market Value
A = Adjusted Net Market Value
E = Energy Value

C = Capacity Value
P = Post-Time-of-Delivery Adjusted Power Purchase Agreement Price
T = Transmission Network Upgrade Costs
G = Congestion Costs
I = Integration Costs
S = Ancillary Services Value

7. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) ~~are not authorized to include language that refers to the use of non-zero~~shall incorporate a $7.50 ($2008) integration cost ~~adders, including any language~~adder in the Net Market Valuation portion of their Least Cost, Best Fit evaluation methodologies. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. This directive shall also apply to Southern California Edison Company in future RPS Procurement Plans unless otherwise directed by the Commission.

8. In the final 2012 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall incorporate terms into their respective pro forma agreements regarding termination rights and buy-down provisions in the event that the results of any interconnection study or agreement indicate that network upgrade costs will exceed a specific amount agreed to by seller and the utility. This directive applies to future pro forma agreements filed by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company will not hold a 2012 solicitation, this requirement shall apply to future use of its pro forma agreement unless otherwise directed by the Commission.

9. Beginning with the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, bids shortlisted by Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall be executed, if at all, within 12 months from the date ~~utilities submit final shortlists to the Commission for approval~~the Commission approves final shortlists, provided that the Commission has approved a subsequent solicitation that is scheduled to begin within 6 months of the expiration date. If no such subsequent solicitation has been approved by the Commission, the expiration will occur on the date that such a subsequent solicitation is approved. This expiration date is included in the schedule adopted herein. If that deadline is not met, the bid will be removed from the shortlist and the utility will not be permitted to execute a bilateral contract for the same project until after the initiation of a subsequent RPS solicitation. The project may be bid into any subsequent RPS solicitation. This directive applies to future RPS solicitations by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, this R.11-05-005

requirement will apply to future SCE solicitations until otherwise directed by the Commission.

10. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company and San Diego Gas & Electric Company are authorized to use in their 2012 RPS solicitations two sets of Time of Delivery factors to reflect energy-only and fully deliverable status. This authorization only applies to the 2012 solicitation. Because Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE is not included.

11. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall modify their RPS bid solicitation protocols, as needed, to require bids have the minimum of a completed California Independent System Operator (CAISO) Generator Interconnection Procedures (GIP) Phase I (or equivalent) study to bid into the solicitation. ~~Additionally, we direct PG&E and SDG&E to modify their bid solicitation protocols to require that projects will need to have the minimum of a completed CAISO GIP Phase II (or equivalent) study to execute a contract.~~ This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with these requirements unless otherwise directed the Commission.

12. In the final 2012 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) R.11-05-005 shall amend their plans such that the minimum nameplate capacity for projects to bid into a solicitation is greater than three megawatts. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with this requirement unless otherwise directed by the Commission.

13. In the final 2012 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company ~~shall remove~~may incorporate its proposed Portfolio-Adjusted Value methodology ~~from~~(as revised in its opening comments on the Proposed Decision) into its solicitation protocol ~~and must include the Least Cost, Best Fit and Net Market Valuation methodologies, referred to in section 5.1 of this decision~~.

14. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall remove the Tax Credit Mitigation Option Term or similar term from their pro forma agreements. Parties are not prohibited from agreeing to include this term in their contracts on a case-by-case basis. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with this requirement unless otherwise directed by the Commission.

15. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) may modify its pro forma agreement and any R.11-05-005 existing contracts under the RPS program to relax the threshold for banks to qualify as eligible to issue letters of credit for RPS contracts. Banks with credit ratings of "A-" from Standard & Poor's Financial Services, LLC or an "A3" rating from Moody's Investors Service, Inc., with an outlook designation of "stable" may participate in the RPS solicitations. This directive applies to future RPS Procurement Plans filed by PG&E unless otherwise directed by the Commission.

16. In the final 2012 Renewables Portfolio Standard Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company shall remove the consideration of bilateral offers.

17. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) may include a provision permitting the resource adequacy component of a contract to cover less than the entire term of the contract. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, SCE may modify future RPS Procurement Plans consistent with this requirement unless otherwise directed by the Commission.

18. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company's (PG&E), Southern California Edison Company's (SCE), and San Diego Gas & Electric Company's (SDG&E) final 2012 RPS Procurement Plans may include a competitive solicitation for the sale of excess RPS products from existing facilities and must rely on the Tier 3 Advice Letter process for the purpose of obtaining approval of contracts for the sale of excess bundled renewable energy and unbundled RECs. This directive applies to future RPS Procurement Plans filed by PG&E, SCE, and SDG&E unless otherwise directed by the Commission.

19. In the final 2012 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, San Diego Gas & Electric Company (SDG&E) shall not include a requirement that the Commission determine or approve the portfolio content category classification as a precondition to the contract's effectiveness. This directive applies to future RPS Procurement Plans filed by Pacific Gas and Electric Company, Southern California Edison Company, and SDG&E unless otherwise directed by the Commission.

20. The following schedule is adopted for the 2012 Renewables Portfolio Standard (RPS) solicitation:

SCHEDULE FOR 2012 RPS SOLICITATION

LINE NO.	ITEM	NO. OF DAYS
1	Mailing of Commission decision conditionally accepting 2012 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2012 RPS Procurement Plans	14 (in addition to state holidays)
3	PG&E and SDG&E issue Requests for Offers (unless amended Plans are suspended by Energy Division Director by Day 24)*	24
4	PG&E and SDG&E notify Commission that bidding is closed	84
5	PG&E and SDG&E notify bidders of shortlist~~; no exclusivity agreements may be required before this date~~	~~144~~Anytime Before 204
6	PG&E and SDG&E submit shortlists to Energy Division and Procurement Review Group	~~154~~Anytime before 214
7	PG&E and SDG&E file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	~~184~~Line 6 + 30 days
8	Commission approval of shortlist becomes final and non-appealable	TBD
~~8~~9	PG&E and SDG&E 2012 RPS Solicitation Shortlists Expire**	~~519~~Line 7 + 365 days
~~9~~10	PG&E and SDG&E submit Tier 3 Advice Letters with contracts/PPAs for Commission approval	TBD

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*The utility may adjust this date to a day after day 24, as necessary, without Commission approval.

** The shortlist expiration shall be extended past the 365 day deadline if no final Commission final order has authorized the commencement of the next IOU RPS RFO within six months of the expiration. In that case, the expiration of the shortlist will occur at the later of the date six months prior to the commencement of the next Commission-authorized RPS RFO or the Commission's final order authorizing the next RPF RFO.

19. The Energy Division Director is authorized, after notice to the service list of this proceeding, to change the schedule as appropriate or as necessary for efficient administration of the 2012 Renewables Portfolio Standard solicitation process.

21. The Integrated Resource Plan Off-Year Supplement filed by PacifiCorp, a multi-jurisdictional utility, and the 2012 Renewables Portfolio Standard (RPS) Procurement Plans filed by the small utilities, Bear Valley Electric Service, a Division of Golden State Water Company, and California Pacific Electric Company, LLC. are accepted. The 2012 RPS Procurement Plans filed by Bear Valley Electric Service, a Division of Golden State Water Company, and California Pacific Electric Company, LLC. are deemed final and no further action is required. No further action is required pertaining to the Integrated Resource Plan filed by PacifiCorp.

22. Pursuant to Pub. Util. Code § 365.1(c)(1) and Decision 11-01-026, we accept the 2012 Renewables Portfolio Standard (RPS) Procurement Plans filed by electric service providers (ESPs), including 3 Phases Renewables, Calpine PowerAmerica-CA, LLC, Commerce Energy, Inc., Commercial Energy of California, Consolidated Edison Solutions, Inc., Constellation NewEnergy, Inc., Direct Energy Business, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC, Gexa Energy California, LC, Noble Americas Energy Solutions LLC, Pilot Power Group, Inc., Praxair Plainfield, Inc., Shell Energy North America (US), L.P., Tiger Natural Gas, Inc. We deem the 2012 RPS Procurement Plans filed by the ESPs as final and no further action is required.

23. The motion filed on April 17, 2012 by Shell Energy North America (US), L.P. and the Direct Access Customer Coalition for Reconsideration of Assigned Commissioner's April 5, 2012 ruling is denied.

24. Rulemaking 11-05-005 remains open.

VERIFICATION

I am an employee of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing "Pacific Gas and Electric's (U 39 E) Opening Comments on the Proposed Decision of ALJ DeAngelis Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Off-year Supplement," dated October 29, 2012. The statements in the foregoing documents are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on this 29th of October, 2012 at San Francisco, California.

/s/ Sandra Burns
Sandra Burns, Principal
Pacific Gas and Electric Company

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