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 2013 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN AND ON-YEAR SUPPLEMENT

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Pursuant to the California Public Utilities Commission's ("Commission") Rule of Practice and Procedure 14.3, Pacific Gas and Electric Company ("PG&E") provides the following comments on the October 15, 2013 Proposed Decision of ALJ DeAngelis Conditionally Accepting 2013 Renewables Portfolio Standard ["RPS"] Procurement Plans and Integrated Resource Plan and On-Year Supplement (the "Proposed Decision").[1/]

I. INTRODUCTION AND OVERVIEW

The Proposed Decision generally approves PG&E's Draft 2013 RPS Procurement Plan (the "RPS Plan"), although it would condition approval on the modification of certain procurement goals or provisions in PG&E's Draft 2013 RPS Form Power Purchase Agreement (the "Form RPS PPA"). In particular, and among other changes, the Proposed Decision would: (1) reject PG&E's procurement goal associated with building and maintaining an adequate bank

1/ By an e-mail to the service list dated October 29, 2013, ALJ DeAngelis permitted parties to file comments of up to 20 pages.

of surplus RPS procurement;[2/] (2) not authorize PG&E to include a provision in its Form RPS PPA that grants PG&E an unlimited paid curtailment option;[3/] (3) require that PG&E must lower the project development security ("PDS") in its Form RPS PPA to match provisions submitted by Southern California Edison Company ("SCE") in its draft 2013 RPS Plan;[4/] (4) not authorize PG&E to include a provision in its RPS Plan that requires the seller to bear all integration-related charges that are attributable to the seller's resource;[5/] (5) reject the contract term length adjustment in PG&E's proposed Portfolio-Adjusted Value ("PAV") methodology;[6/] and (6) require that PG&E make public certain RPS cost data unless doing so would reveal a single contract price.[7/] Additionally, the Proposed Decision would adopt a new standard term and condition ("STC") to replace the existing STC 2,[8/] and it states that the 2013 RPS Solicitation will be guided by a new Renewable Net Short ("RNS") methodology that has not yet been determined.[9/]

PG&E's comments focus on these modifications to its proposed 2013 RPS Plan, and PG&E explains below why the Proposed Decision should be revised on each of these points. Appendix 1 provides proposed revisions to the findings of fact, conclusions of law, and ordering paragraphs in strikeout/underline format. In all other respects, PG&E supports the Proposed Decision as it applies to PG&E's RPS Plan.

2/ *See* Proposed Decision at 44.

3/ *Id.* at 72 (Ordering Paragraph ("OP") 13).

4/ *Id.* at 48.

5/ *Id.* at 73 (OP 17).

6/ *Id.* at 73 (OP 16).

7/ *Id.* at 73 (OP 19).

8/ *Id.* at 70 (OP 6).

9/ *See id.* at 8.

A. The Commission Should Clarify That Changes It Requires to the Form RPS PPA Do Not Prohibit or Prejudge the Reasonableness of Subsequently Executed RPS PPAs with Different Terms and Conditions.

An overarching issue that is common to the Proposed Decision's discussion of curtailment, PDS, and integration cost allocation provisions is the need to clarify that the changes the Proposed Decision would require to these provisions in PG&E's Form RPS PPA do not prohibit PG&E from negotiating different terms in these areas with its counterparties, including the provisions that Proposed Decision requires be removed from the Form RPS PPA. The Commission should revise the Decision to remove inconsistencies that could cast doubt on its long-standing preference that investor-owned utilities ("IOUs") first negotiate any needed changes to standard contract terms with counterparties and then submit the terms to the Commission for review of the resulting executed contracts in their totality.[10/]

To the extent the Proposed Decision may be read as limiting the parties' ability to negotiate efficient and mutually-agreeable curtailment, PDS, and integration cost provisions, the Proposed Decision would represent a dramatic and alarming change to the RPS procurement process. The history of the RPS Program demonstrates the ability of the IOUs to negotiate reasonable terms and conditions in their executed PPAs, even when those terms are materially different than the RPS Form PPA. The discretion to negotiate such changes is critical in light of the fast pace of regulatory and market changes in RPS procurement, and any Commission intent to mandate non-modifiable terms or to prohibit specific terms in these critically important and nuanced provisions of the agreements would likely increase the overall cost of RPS implementation by limiting parties' ability to negotiate lowest-cost, efficient agreements.

The Proposed Decision correctly notes that "the pro forma agreements are negotiable,

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10/ *See* Proposed Decision at 34.

except for the [non-modifiable] 'standard terms and conditions' and serve as the starting point for negotiating a final agreement between the seller and utility."[11/] Yet this long-standing policy may be contradicted by other ambiguous language in the Decision, detailed in specific comments below, that may be read to prohibit or limit the parties' ability to negotiate terms different than those in the Form RPS PPA. The Commission should adopt the changes proposed in these comments to remove this ambiguity. In doing so, the Commission should confirm that in the RPS Plan proceeding, it reviews policy issues at a general level and approves a Form RPS PPA that is a reasonable starting point for negotiations between the parties. The Commission cannot, and should not, attempt to prejudge in the abstract context of the high-level RPS Plan proceeding whether any particular executed PPA is reasonable. Rather, the Commission should reaffirm its long-standing policy that parties may negotiate terms that change the modifiable provisions in the Form RPS PPA and that the Commission will review the reasonableness of those negotiated provisions in light of the whole of the agreement once it is submitted by an IOU.

II. COMMENTS ON SPECIFIC ISSUES

A. The Commission Should Approve PG&E's Procurement Goal Related to Building a Surplus RPS Compliance Bank and Limit Such Procurement to 2,400 GWh during the 2013 RPS Plan Cycle.

The Proposed Decision would find it unreasonable at this time to accept PG&E's procurement proposal and strategy to build and maintain an adequate bank of surplus RPS procurement (the "Banking Strategy").[12/] The Proposed Decision bases this finding on what it claims are (1) a lack of quantitative analysis by PG&E, (2) the absence of a clear procurement

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11/ *Id.* at 65 (Finding of Fact ("FOF") 23; *id.* at 33 (fn. 78). *See also id.* at 33. Note that in the first two of these citations, the Proposed Decision appears to contain an error in the omission of the word "non-modifiable" before "standard terms and conditions." The Commission has previously made clear that some STCs are modifiable, and some are non-modifiable. *See, e.g.,* Decision ("D.")08-04-009 at 2-3. PG&E's proposed modifications in Appendix 1 to these comments correct this apparent error.

12/ Proposed Decision at 44.

goal for the additional procurement, and (3) the appearance that PG&E's projected Bank appears to be substantial.[13] However, the Proposed Decision notes that the Commission may revisit PG&E's Banking Strategy if PG&E provides a more robust justification, including "clear procurement goals."[14] PG&E responds in these comments by setting forth a clearer procurement goal for building and maintaining an adequate Bank. The Commission should revise the Proposed Decision to approve PG&E's Banking Strategy as modified by these comments.

PG&E can best meet its objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to procure RPS products. Because recent market indications suggest that near-term initial deliveries of RPS products that would be eligible to be banked for future compliance use may be cost-effective when compared with the alternative cost of procurement from contracts with distant initial delivery dates, PG&E proposed to solicit offers for such near-term, bankable products as part of its 2013 RPS Solicitation.[15] The Banking Strategy is in addition to, and distinct from, PG&E's separate goal to procure up to 1,500 gigwatt-hours ("GWh") per year in incremental procurement with long-term deliveries beginning toward the end of this decade (the "Incremental Procurement Goal").[16]

While PG&E did not initially set a volume target for the Banking Strategy in its RPS Plan, PG&E now proposes to revise its Banking Strategy to solicit RPS agreements that would result in procurement of bankable products equivalent to no more than 2,400 GWh in total.[17]

13/ *Id.*; *see also id.* at 64 (FOF 14).

14/ *Id.* at 44.

15/ PG&E's RPS Plan at 36.

16/ *Ibid.*

17/ Unlike the Incremental Procurement Goal, which is expressed as a long-term, annual additional amount of procurement, the Banking Strategy cap is expressed as a total volume. For example, the 2,400 GWh cap

This 2,400 GWh cap is a fraction of the forecasted eligible quantity that is allowed to count for RPS compliance given the restrictions on the quantity of Portfolio Content Category ("PCC") 2 and 3 products that can be used each compliance period.[18/]

While the Proposed Decision correctly notes that PG&E expects to build a considerable Bank under the expected-case scenarios in the Draft Plan, it is important to recognize that the Renewable Net Short ("RNS") forecasts are a snapshot in time and are highly dependent on assumptions regarding PG&E's portfolio, load growth, current conditions in the renewable energy industry, and broader uncontrollable and unpredictable events such as wind, solar, and hydro energy deliveries. PG&E finds it reasonable to add to its Bank based on both the potential for the more pessimistic scenarios presented in the RPS Plan's RNS to unfold, and the value presented by low prices for bankable RPS products that justifies covering such scenarios at this time.

Approval of the Banking Strategy and the cap of 2,400 GWh proposed in these comments would not represent pre-approval of any deals actually negotiated under this authority, but rather would simply allow PG&E to seek offers and thereby indicate to the market the potential demand for such products. If and when it actually executes an agreement in pursuit of its

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proposed in these comments could be met from a ten-year contract with deliveries of 240 GWh per year. The cap proposed in these comments is only meant to apply to the 2013 RPS Plan cycle; the adequacy of PG&E's Bank will depend at any particular time on whether the Bank can reasonably achieve its purpose of reasonably ensuring compliance. Used to manage both demand- and supply-side variability, a Bank complements PG&E's Incremental Procurement Goal. Over time, as PG&E either procures with the intent of building its Bank or sells surplus RPS procurement that would reduce the size of its Bank, the adequacy of the Bank will be revaluated to balance the cost of maintaining it against the risk of future potential and actual increases in future long-term procurement costs if an adequate Bank is not maintained. *See* PG&E Draft 2013 RPS Plan at 70. That comparison, as well as a reassessment of plausible risk scenarios, could result in changes to what PG&E believes is an adequate Bank in the future.

18/ Using PG&E's August 2013 Compliance Report as a reference, the proposed Banking Strategy cap could result in procurement of no more than approximately one-third of PG&E's projected ability to use PCC 2 and 3 products in the second compliance period (2014-2016). PG&E notes that long-term PCC 1 projects could also contribute to the surplus bank if the start dates are well ahead of 2020, but their prices will need to be significantly below the rest of the market in order to be competitive. *See* RPS Plan at 84, fn. 43.

Banking Strategy, PG&E will submit that agreement with an advice letter to the Commission presenting a detailed case regarding why PG&E believes that the procurement opportunity is a reasonable way to ensure compliance and provides commensurate value to customers compared to other alternatives.[19/] Any transactions executed in furtherance of the Banking Strategy will need to be justified based on value, need, or a combination of the two. In its justification, PG&E will further assess the considerations relevant to the Commission's review, including the current and projected size of PG&E's Bank and the projected cost of alternative procurement to ensure compliance. The Proposed Decision prematurely limits PG&E's ability to even solicit offers pursuant to the Banking Strategy, and may thereby preclude least-cost, best-fit compliance with the RPS statute.

Opportunities to procure cost-effective RPS products that meet the Banking Strategy's criteria may be fleeting, and if the Commission's final RPS Plan decision continues to reject PG&E's proposal to solicit such products, PG&E may lose opportunities to achieve the lowest-cost RPS portfolio. These opportunities can exist for a variety of reasons, but currently the portfolio content categories created by Senate Bill (SB) 2 (1X)[20/] have led to an imbalance in the supply of and demand for PCC 3 products. Based upon PG&E's recent market interactions, the most economic PCC 3 vintages are those with earlier retirement dates (e.g., RECs generated in 2012 or 2013, which lose their California RPS compliance value if not retired in the near-term). This market phenomenon incents PG&E to seek PCC 3 products that would comply with

19/ In fact, PG&E has provided this kind of detailed analysis of its bank as part of the filings for two recent PCC 3 transactions. *See* Advice Letter 4301-E, filed October 10, 2013, Appendix H (seeking approval of a Purchase and Sale Agreement for the Procurement of Eligible Renewable Energy Credits between NextEra Energy Power Marketing, LLC and Pacific Gas and Electric Company); Advice Letter 4299-E, filed October 10, 2013, Appendix H (seeking approval of a Purchase and Sale Agreement for the Procurement of Eligible Renewable Energy Credits between Sterling Planet, LLC and Pacific Gas and Electric Company).

20/ *See* Cal. Pub. Util. Code § 399.16.

statutory restrictions on the use and bankability of such products in the first or second compliance periods. To ensure that PG&E's customers have an opportunity to take advantage of current market opportunities to procure eligible RPS products at the lowest cost,[21/] the Commission should approve PG&E's Banking Strategy with the reasonable cap proposed in these comments.

B. The Commission Should Approve PG&E's Proposed Curtailment Provisions as a Starting Point for RPS PPA Negotiations.

The Proposed Decision would not authorize PG&E to "include a pro forma contract provision that requires buyer to agree to unlimited curtailment."[22/] While the Proposed Decision acknowledges that "buyer curtailment in the RPS context may create additional operational flexibility," it finds that PG&E would not likely need to curtail a generator 8,760 hours per year and that it would be unreasonable "for ratepayers to be responsible for all the risk and for the costs of a contract executed for the purposes [of] receiving RPS-eligible generation and associated RECs only to have the potential that it will never actually receive any renewable energy credits pursuant to the contract."[23/] The Proposed Decision includes the broad conclusion that "[u]nlimited buyer curtailment is not reasonable due unknown risks and benefits."[24/]

PG&E urges the Commission to modify the Proposed Decision's language regarding

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21/ The Proposed Decision's rejection of PG&E's procurement goal related to the Banking Strategy could lead to unintended and costly outcomes. For example, if the Commission were to implement the Proposed Decision as a de facto prohibition on procurement of products that would be delivered prior to 2020 and banked for future compliance, PG&E could be prevented from procuring products that present indisputable customer value. For example, PG&E would have to reject offers for RECs priced at just a few cents, or would be unable to optimize its portfolio by simultaneously selling high-priced PCC 1 products and replacing them with low-priced PCC 3 products that offer the same compliance value. PG&E finds it unlikely that the Commission would want to eliminate such opportunities even before the transactions can be executed and submitted to the Commission for further consideration.

22/ Proposed Decision at 72 (OP 13).

23/ *Id.* at 39.

24/ *Id.* at 67 (COL 15).

curtailment for three reasons. First, the approach to PG&E's curtailment provisions is inconsistent with the separate, reasonable approval of SCE's pro forma PPA language. Second, the Proposed Decision fails to recognize and adhere to the Commission's well-established precedent of assessing the reasonableness of executed PPAs in their totality. Finally, the Proposed Decision's conclusions are overbroad and should be narrowed even if the Commission maintains the general approach.

In the same discussion that the Proposed Decision rejects PG&E's proposed curtailment provisions because it finds they unreasonably give a potentially unlimited curtailment right to PG&E, the Proposed Decision accepts SCE's curtailment provisions that similarly provide a potentially unlimited curtailment right.[25/] PG&E understands that under its proposed pro forma PPA, SCE must pay the seller for curtailments in excess of 50 hours per year or that occur during on-peak hours, and the amount of such paid curtailment is not limited.[26/] Curtailments of up to 50 hours per year would be unpaid, so long as they were not during on-peak hours.[27/] During the final year of the contract, SCE has the option to extend the contract for up to two additional years, or until seller delivers to SCE double the curtailed volume that SCE paid for over the life of the contract, whichever comes first.[28/]

SCE's unlimited curtailment rights are similar to the provisions PG&E proposed, with the addition of a buyer option to require delivery of curtailed energy at the end of the initial delivery term. PG&E agrees that such an extension provision may be reasonable in certain cases, and

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25/ *See id.* at 38. *See also id.* at 72 (OP 13) ("The minor revisions proposed by [SCE] to the curtailment provisions are accepted.").

26/ *See* SCE Amended 2013 RPS Procurement Plan, Appendix G.1., 2013 Pro Forma Renewable Power Purchase and Sale Agreement, Provision 3.12 (g), p. 30.

27/ *See id.*, Provision 4.01(c), p.41.

28/ *See id.*, Provision 1.05(b), p. 4.

agrees with the Proposed Decision therefore that it is reasonable for SCE to include it as a starting point for negotiations in its form PPA. However, PG&E fails to see a rational basis in the Proposed Decision's rejection of PG&E's similar curtailment provisions.

The Proposed Decision also errs when it bases rejection of PG&E's provisions on its skepticism that PG&E "will actually need to curtail a generator 8,760 hours per year"[29/] and reads PG&E's RPS Plan "to require unlimited curtailment." Nothing in PG&E's RPS Plan requires PG&E to exercise unlimited curtailment or makes curtailment of 8,760 hours per year likely. Rather, PG&E's Form RPS PPA merely proposes, *as a starting place for definitive contract negotiations,* that PG&E be granted an *unlimited option* to economically bid (which, may result in curtailment) and in some cases, for the sake of mitigating over-generation events, to curtail generation. PG&E is not seeking in this decision any Commission determination regarding the reasonableness of the unlikely scenario in which PG&E actually exercised unlimited curtailment in the future. Prior to that unlikely occurrence, PG&E would first have to execute an agreement that included the Form RPS PPA curtailment provisions, the Commission would have to find the agreement reasonable in its totality, load and resource conditions would have to arise that preclude cost-effective use of the energy produced by the resource (*e.g.*, where PG&E's customers could be forced to pay negative CAISO prices for delivered energy and also pay the seller the contract price), and then PG&E would have to act reasonably in administering the contract when deciding to curtail all hours of delivery. Because all of these determinations and outcomes are very fact-specific in nature and the actual exercise of an economic bidding or curtailment option for all hours of a delivery term is highly unlikely, the Commission need not and should not attempt to determine in this high-level RPS Plan proceeding whether PG&E

29/ *See id.* at 38-39.

could ever reasonably exercise its curtailment rights in this manner.

If notwithstanding the comments above the Commission were to retain the requirement that PG&E must revise its Form RPS PPA curtailment provisions, PG&E intends to revert to its approved 2012 Form PPA provisions, which allow the Seller to fill in a blank specifying how many hours of Buyer Curtailment it will accept. Even in that case, however, the Commission should remove ambiguity in the Proposed Decision that may be read to suggest that any actual, executed PPA with unlimited curtailment rights would be *per se* unreasonable. As discussed in Section I.A. of these comments, the Commission should not in this Decision preclude or prohibit specific provisions in executed contracts, but rather should approve reasonable starting language for the negotiations of definitive PPAs.[30/]

C. The Commission Should Approve the Project Development Security Provisions in the Form RPS PPA.

The Proposed Decision concludes that "[w]ithout additional evidence, PG&E proposed project development security [("PDS")] of $300/kW for [PCC] 1 and 2 products, which is higher than SCE's and SDG&E's, is unreasonable."[31/] It would require PG&E to reduce the proposed $300/kilowatt ("kW") to $90/kW for baseload resources and $60/kW for intermittent resources for PCC 1 and 2 products, in part because those are the same or similar levels adopted by the other IOUs.[32/]

The Commission should revise the Proposed Decision to allow PG&E's proposed PDS

30/ The changes proposed in Appendix 1 assume the Commission approves PG&E's curtailment provisions as proposed. If the Commission were to retain the Proposed Decision's general approach, it should, at a minimum, revise Conclusion of Law 15 and the discussion on page 39 to make clear that it is not instituting a blanket prohibition on unlimited curtailment provisions on executed PPAs, but rather will evaluate any such provisions in the context of the totality of the PPA when it is submitted for approval.

31/ *Id.* at 68 (COL 21).

32/ *Id.* at 48.

term as a starting point for contract negotiations. First, PG&E's proposed PDS terms have contributed to a successful 2012 RPS solicitation, where the higher PDS encouraged developers to make sure they had selected the most viable projects before executing a PPA. Second, because SCE is seeking PPAs that begin delivering in 2016,[33/] while PG&E is seeking Incremental Procurement that may begin delivering in 2020 or later, the IOUs are not identically situated with respect to project viability risk, and there is no basis to mandate uniformity in PDS provisions.

In any case, PG&E understands the Proposed Decision's reference to "additional evidence"[34/] as allowing for the possibility that the totality of a particular, executed PPA may justify and make reasonable a PDS of $300/kW, even if the Commission requires that the Form RPS PPA include provisions for lower PDS.[35/]

D. The Commission Should Not Ignore the Operational Risks and Likelihood of Costs Associated with the Integration of Intermittent Resources Even If It Continues to Prohibit an Integration Adder in Bid Evaluation.

The Proposed Decision conflates the issue of integration in the contexts of RPS bid evaluation, provisions in the Form RPS PPA, and risk allocation provisions in future executed RPS PPAs. The result is a vague and ambiguous decision that only compounds the existing integration cost risks faced by PG&E's customers. Even if the Commission does not in this decision reverse its policy prohibiting the use of an integration adder in RPS bid evaluation, it should not exacerbate the problem by prohibiting IOUs and their counterparties from including provisions in contracts to allocate the risks and costs associated with integration.

The Proposed Decision mischaracterizes PG&E's approach to integration costs.

33/ *See* SCE Amended 2013 Procurement Plan, App. F.1 (2013 Procurement Protocol), Provision 1.03(a).

34/ Proposed Decision at 68 (COL 21).

35/ *See* Discussion in Section I.A., *supra*.

Although it purports to reject "PG&E's requests to use non-zero integration cost adders as part of the [least-cost, best-fit ("LCBF")] evaluation of bids and contract in the 2013 RPS Procurement Plans," the Proposed Decision fails to acknowledge that PG&E did in fact propose a zero integration adder in its LCBF methodology, as required by D.12-11-016.[36/] In fact, while it does not agree with the Commission's policy, PG&E did not propose revising it given the language in the 2012 RPS Plan decision.[37/] Nor does PG&E's Form RPS PPA contain any provision requiring a seller to bear all integration-related costs.[38/] Instead, PG&E's Draft RPS Plan simply puts the market on notice that PG&E will seek to allocate integration cost risk to sellers so long as there is no integration cost adder used in evaluation of bids.[39/]

Because PG&E's RPS Plan merely states an intention and approach to future negotiations, and the actual outcome of those negotiations is uncertain, there is no need or concrete basis for the Commission to approve or reject PG&E's statement at this time. Rather, the Commission should determine the reasonableness of any actual integration cost allocation provisions contained in executed PPAs in light of the regulatory and market conditions in place

36/ PG&E RPS Plan, App. 6 (Draft 2013 RPS Solicitation Protocol), Attach. K, p. 7 ("Pursuant to D.12-11-016, integration costs are assumed to be zero.").

37/ The Proposed Decision states retail sellers "may seek authority" in the future to amend the Plan to incorporate any integration adder developed by the California Independent System Operator ("CAISO") or the Commission. At p. 28. However, no other Commission proceeding appears to be actively developing an integration cost adder. For example, R.11-10-023 has only adopted a flexibility framework for compliance in 2015-2017, and does not have within scope the development of an integration cost charge. R.12-03-014 has never had within its scope the development of an integration cost, and given the recent cancellation of Track 2 of that proceeding, will not even address the need for flexible capacity in the near-term. While PG&E supports a holistic review of integration issues both inside and outside of the RPS Program, the Commission should not fail to develop an RPS integration cost adder simply because of a lack of coordination between its proceedings.

38/ *Cf. id.* at 46 ("[W]e do not accept PG&E's proposal to include a term in its pro forma contract that sellers bear all integration-related charges attributable to the resource's output."); *ibid.* ("We direct PG&E to remove any requirements that sellers are responsible for all integration costs that [are] attributable to a resource's output.").

39/ PG&E notes that if there are no integration costs associated with intermittent resources, as the Commission's current policy implies, then provisions in a contract allocating such costs would not represent any real liability, and there would be no need to prohibit the provisions.

at the time those provisions are executed and submitted to the Commission, and in light of the totality of the PPA.

More fundamentally, the Proposed Decision errs in holding that PG&E's mere statement of intention to seek certain cost allocation provisions is a violation of the previously-adopted policy to prohibit a non-zero integration cost adder in the LCBF methodology.[40/] As noted above, PG&E's RPS Plan explicitly adopts a zero integration cost adder in bid evaluation in compliance with Commission policy. But because nearly all parties to the rulemaking have noted the need to address integration costs,[41/] PG&E is prudently indicating its intent to negotiate allocation of any such costs as part of future PPA negotiations.

Given the Commission's stated intent to examine integration costs further in future phases of this proceeding and/or other proceedings, it is appropriate for the IOUs to allow for that possibility of such costs in their future contracts, and to seek to allocate integration cost risk to sellers. The Commission's adoption of a flexible capacity framework in the last Resource Adequacy decision[42/] is an acknowledgement that new flexible requirements are needed, resulting in new costs associated with integrating intermittent renewable generation. Similarly, the California Independent System Operator's ("CAISO") planning studies have projected integration-related increases in ancillary services in the form of regulation and load following requirements.[43/] These decisions and studies show that renewable integration costs are real.

40/ *See id.* at 28 ("PG&E's proposal essentially results in a non-zero integration cost adder. The result proposed by PG&E is inconsistent with today's decision to continue the policy of a zero integration cost adder."); *id.* at 46 ("PG&E's proposed contract provision is inconsistent with the Commission's current orders to use a non-zero [sic] integration cost adder . . . .").

41/ PG&E has noted in the past that the great majority of parties support moving away from the past policy of assuming no integration costs. *See* PG&E Reply to Comments on RPS Plans and New Proposals, filed in R.11-05-005 on July 18, 2012 at 15, fn. 40.

42/ *See* D. 13-06-024 at 69 (OP 5).

43/ The CAISO projects that regulation and load following requirements would increase to about 1,300 MW

Accordingly, they must be contractually allocated in order to avoid wasteful and expensive litigation in the future. PG&E believes that so long as it cannot consider such costs in bid evaluation, sellers should bear such costs. Such a negotiation strategy prudently seeks to protect PG&E's customers from likely costs of procurement not currently captured in the LCBF methodologies.

E. The Commission Should Allow PG&E to Revise its LCBF Methodology to Consider Debt Equivalence.

The Proposed Decision accepts without comment SCE's proposed LCBF methodology, including consideration of debt equivalence,[44/] but would require PG&E to exclude a contract term length adjustment from its PAV calculation within the LCBF methodology.[45/] The debt equivalence associated with longer-term, higher-notional-value contracts will tend to be greater than that associated with shorter-term contracts, meaning that debt equivalence and term length are correlated. If the Commission continues to require PG&E to exclude the contract term length adjustment in the final decision, it should allow PG&E to incorporate into its LCBF methodology debt equivalence criteria similar to those proposed by SCE. Since PG&E's term length adjustment went beyond debt equivalence, PG&E may renew its request for a term length adjustment in its 2014 RPS Plan.

F. The Commission Should Follow Statutory Precedent and Allow Redaction of Aggregated Data When There Are Fewer Than Three Contracts.

The Proposed Decision denies PG&E's motion to seal, in part, and would order that

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and about 3,600 MW respectively by 2022 with 33% RPS in the Commission's 2012 LTPP Base Scenario. *See* CAISO's Review of Scenario Assumptions and Deterministic Results, Slide 25, CPUC LTPP Track 2 Workshop, August 26, 2013 (available at: http://www.cpuc.ca.gov/NR/rdonlyres/C856A74F-1B6A-45A4-8272-98883F909583/0/CAISOOperatingFlexibilityModelingResults.ppt).

44/ *See* SCE Amended 2013 Procurement Plan, App. F.1 (2013 Procurement Protocol), Provision 4.01, p. 14.

45/ Proposed Decision at 73 (OP 16).

certain aggregated historic and forecast expenditures by resource type be publicly disclosed, "unless doing so would reveal a single contract price."[46] If the Commission retains this aspect of the decision, it should at a minimum provide that aggregated data may remain redacted if the aggregation involves fewer than three. The Legislature has already determined that two contracts was an appropriate threshold when requiring public reporting of aggregated RPS cost data.[47] Using the "fewer than three" criterion both increases administrative simplicity by harmonizing confidentiality requirements across proceedings and requests, and also helps to prevent the disclosure of contract-specific information that the Commission and the Legislature have determined is market-sensitive, since aggregation of two contracts may allow the price of a single contract to be determined when analyzed in combination with other publicly-available data.

G. The Commission Should Revise the New Standard Term and Condition ("STC") 2 and Clarify Its Applicability.

The Proposed Decision would replace the existing non-modifiable STC 2 with a new STC 2. It orders that the IOUs use the new STC 2 "in all contracts for RPS procurement signed on or after January 1, 2014."[48] This order requires clarification and revision. First, the Commission should make clear that it is only requiring STC 2 be added to non-modifiable form PPAs[49] to the extent those contracts are for biomethane-derived RPS products. Further, if STC 2 is added to non-modifiable forms, it should be amended to more closely track the statutory

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46/ *Id.* at 73 (OP 19); *see also id.* at 49.

47/ Cal. Pub. Util, Code § 911(b) ("The commission shall not be required to release the data in any year when there are fewer than three contracts approved.").

48/ *Id.* at 70 (OP 6).

49/ For example, the Renewable Auction Mechanism ("RAM") Program and the Renewable Market-Adjusting Tariff ("Re-MAT") Program.

language that requires it.[50/]

Second, the Proposed Decision is internally inconsistent in stating that "[t]he new STC will not retain the 'non-modifiable' status"[51/] of the prior STC 2 while ordering it to be incorporated into "RPS procurement signed on or after January 1, 2014."[52/] Presumably, the Commission means that the Form RPS PPA should incorporate the new STC, but parties may delete or modify the provision as appropriate under the circumstances of any specific transaction. The Commission should make clarifying changes to the Proposed Decision as shown in Appendix 1 to these comments.

H. The Commission Should Wait Until the 2014 RPS Plan Cycle to Propose a New RNS Methodology.

The Proposed Decision states that Energy Division Staff plans to develop "another RNS methodology . . . for use by the utilities in the 2013 solicitation."[53/] PG&E notes that the retail sellers' procurement plans are based on the results of the existing RNS methodology, and that changes to that methodology could have major implications for the procurement strategies and goals the plans put forward. Any such change should only be made after adequate opportunity for notice and comment, and the change should only go into effect in the 2014 RPS planning cycle. The Commission should not approve future changes to the RNS methodology in this decision when it does not know what those changes will be or that they will be consistent with

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50/ Specifically, Cal. Pub. Util. Code § 399.12.6(f) refers only to restrictions on *buyers* from making claims regarding greenhouse gas reductions from a biomethane facility under contract to a load-serving entity. The proposed STC 2 would also restrict *sellers* from making any claims regarding such reductions, even if they were unrelated to the contract with the load-serving entity. A seller may have other greenhouse gas reductions pursuant to other procurement contracts, and it should be free to market those separate reductions in voluntary markets and/or compliance markets such as the Cap and Trade Program under Assembly Bill 32 ("AB 32").

51/ Proposed Decision at 24.

52/ *Id.* at 70 (OP 6).

53/ *Id.* at 8.

the approved 2013 RPS plans.

III. CONCLUSION

For the reasons stated above, PG&E requests that the Commission revise the Proposed Decision as shown in Appendix 1 and otherwise discussed in these comments. Specifically, the Commission should: (1) approve PG&E's Banking Strategy with a 2,400 GWh cap; (2) approve PG&E's proposed curtailment provisions in the Form RPS PPA; (3) approve PG&E's proposed PDS in the Form RPS PPA; (4) decline to prohibit or preclude PG&E from negotiating any specific curtailment, PDS, or integration provisions in any future contract; (5) allow PG&E to consider debt equivalence in its LCBF methodology if the Commission excludes PG&E's proposed contract term length adjustment; (6) allow redaction of aggregated cost data if three or fewer contracts are included; (7) clarify and revise the new STC 2; and (8) revise the RNS, if at all, only for the next RPS solicitation cycle.

Respectfully Submitted,

CHARLES R. MIDDLEKAUFF
M. GRADY MATHAI-JACKSON

By: /s/ M. Grady Mathai-Jackson
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Dated: November 4, 2013

Appendix 1: Proposed Revisions to Findings, Conclusions, and Orders

FINDINGS OF FACT

1. Provided that SDG&E's Commission-approved projects achieve commercial operation, SDG&E will likely have fulfilled its renewables commitment per D.08-12-058 on the Sunrise Powerlink Transmission Project. SDG&E's Commission-approved projects include approximately 3,600 GWh.

2. A value component to reflect existing facilities with expiring contracts exists within the LCBF methodology.

3. PG&E provides for offers for extension so that existing facilities can compete in the RPS solicitations and secure extensions before PG&E fills in its long-term next short.

4. The 2013 draft RPS Procurement Plans filed by SDG&E and PG&E refer to so-called green pricing options which the Commission is evaluating in other proceedings.

5. An integration cost adder must be developed and be based on an assessment of system-wide grid impacts and the costs to customers. This analysis should include ways that renewable procurement can be used to enhance grid reliability.

6. The record of this proceeding is insufficient to assess the risks and benefits to ratepayers and the resource adequacy market on the topic of a seller's offer to include third-party resource adequacy.

7. A completed Phase II transmission study provides more certainty regarding transmission costs and timing and is a reasonable approach to minimize project failure risk.

8. The increased level of competition in the renewables market renders *shortlist exclusivity* unnecessary.

9. A contract term that requires sellers to accept a lower price if deliveries fail to conform to seller's delivery profile (within a designated margin of error) offers utilities a means of managing supply.

10. In the absence of contract-specific information, the Commission is unable to determine the ~~The~~ value of an unlimited buyer curtailment right~~is not known~~. A retail seller must demonstrate the reasonableness of an executed PPA containing such a right in any advice letter submitting the PPA for Commission approval. The Commission will review the reasonableness of a PPA in its totality.

11. The more limited changes to curtailment by the buyer, such as proposed by SCE, will not impact project financing.

12. In evaluating preferences, we seek to balance providing the utilities with a reasonable

amount of discretion in establishing the parameters of their solicitations with obtaining the most favorable outcomes in the solicitations by not unduly restricting seller participation with otherwise beneficial projects.

13. We envision the RPS Program as a program with broad eligibility.

14. While the Commission will allow PG&E to solicit offers of up to 2,400 GWh total that are intended to build and maintain its surplus bank, the burden is on PG&E to demonstrate the need for such additional banked surplus when it submits those transactions for approval.~~It is unclear that PG&E needs additional procurement under the "adequate" bank proposal due to the absence of analysis.~~

15. Regarding PG&E's proposed change to its PAV methodology, PG&E did not demonstrate the representative cost to PG&E and its ratepayers by the "contract term length" adjustment. SCE's use of debt equivalence in its LCBF methodology accomplishes a similar goal.

~~16. PG&E's proposal to require sellers to bear all integration-related charges attributed to the seller's resource is not supported by the record in this proceeding.~~

17. Deferring the adoption of a non-zero integration cost adder for purposes of bid evaluation is reasonable until developed in a public forum. In the meantime, it is prudent to allow retail sellers to negotiate provisions in their PPAs that allocate any future costs that are attributable to integrating the seller's resource. The Commission will judge the reasonableness of such allocations when executed PPAs are submitted for approval.

~~18. PG&E does not sufficiently justify its proposed project development security of $300/kW for Portfolio Content Category 1 and 2 products.~~

19. Public disclosure of the PG&E RPS cost quantification information, cited here, will not harm PG&E or its ratepayers.

20. SCE's modification to its LCBF methodology for only the 2013 solicitation to include a congestion cost adder to energy-only projects may appropriately address the risks related to transmission capacity for those projects.

21. No clear benefits exist with SCE's proposal to impose the risks of negative pricing on sellers of energy-only projects.

22. Additional information is needed from PacifiCorp regarding its planned unbundled REC solicitation.

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

24. Praxair and Liberty Power Delaware are ESPs and do not serve any retail load.

CONCLUSION 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. With approximately 3,600 GWh under contract, it is reasonable to find that SDG&E will likely have fulfilled the directive in D.08-12-058 regarding renewable contracts facilitated by Sunrise Powerlink Transmission Project.

3. Because a value component to reflect existing facilities with expiring contracts exists within the LCBF, no further value component is needed.

4. Existing contracts have opportunities in the upcoming solicitation as noted by PG&E provision for *offers for extension* so that existing facilities can compete in the RPS solicitations and secure extensions before PG&E fills in its long-term next short.

5. While the 2013 draft RPS Procurement Plans filed by SDG&E and PG&E refer to so-called green pricing options, which the Commission is evaluating in other proceedings, this decision does not find that procurement described in these separate application proceedings is RPS-eligible.

6. Because an RPS integration cost adder should depend on a broader assessment of the electric system's needs, we refrain from adopting an RPS integration cost adder for purposes of bid evaluation in this decision.

~~7. PG&E's proposal to require sellers to bear all integration-related charges attributed to the seller's resource is not authorized because it is not support by the record in this proceeding.~~

8. Because the record of this proceeding is insufficient to assess the risks and benefits to ratepayers and the resource adequacy market on the topic of a seller's offer to include third-party resource adequacy, we do not adopt the proposal today.

9. We accept SCE's and SDG&E's Phase II (or equivalent) study requirement because requiring projects to have at minimum a completed Phase II transmission study provides more certainty regarding transmission costs and timing and is a reasonable approach to minimize project failure risk. PG&E should also incorporate this requirement into its final 2013 RPS Plan.

10. The contract negotiating arrangement referred to as *shortlist exclusivity* is not permitted based on the increased level of competition in the renewables market.

11. The TOD factors presented in the 2013 RPS Procurement Plans are reasonable although different from those applied in 2012 or previous years.

12. It is reasonable to allow utilities to require a delivery profile from sellers because the information offers increased supply predictability.

13. Consistent with past Commission decisions, utilities are not required to compensate sellers for the loss of production tax credits due to curtailment.

14. It is reasonable for utilities to solicit offers based on the preferences set forth in the 2013 RPS Procurement Plans.

15. The reasonableness of an u~~U~~nlimited buyer curtailment right can only be assessed in light of the totality of an executed PPA.~~is not reasonable due to unknown risks and benefits.~~

16. The minor revisions to buyer curtailment proposed by SCE are reasonable because the modifications will not impact project financing.

17. Utilities may rely on preferences for project sizes for their solicitations but the RPS Program remains potentially available to all projects with a minimum size of 1.5 MW.

18. PG&E may solicit offers to build a surplus bank of procurement, but the reasonableness of any such procurement can only be determined after the submission of transactions in furtherance of PG&E's strategy and based upon the demonstration submitted with such offers.~~In the absence of sufficient analysis, PG&E has not demonstrated its need for additional procurement to establish an "adequate" bank.~~

19. PG&E's proposed change to its PAV methodology is not accepted because PG&E did not demonstrate the representative cost to PG&E and its ratepayers by the "contract term length" adjustment. PG&E may instead consider debt equivalence in its LCBF methodology. In all other respects, the PAV methodology is accepted.

~~20. The record of this proceeding does not support adoption of a contract provision requiring sellers to bear all integration-related charges attributable to the seller's resource.~~

~~21. Without additional evidence, PG&E proposed project development security of $300/kW for Portfolio 1 and 2 products, which is higher than SCE's and SDG&E's, is unreasonable.~~

22. PG&E's request for confidential treatment of its RPS cost quantification information is denied, in part, because we find that making this aggregated RPS cost data public will not harm PG&E or its ratepayers.

23. SCE's modification to its LCBF methodology for only the 2013 solicitation to include a congestion cost adder to energy-only projects may appropriately address the risks related to transmission capacity for those projects.

24. SCE's proposal to impose the risks of negative pricing on sellers of energy-only projects is not accepted due to the absence of clear benefits.

25. Additional information is needed from PacifiCorp regarding its planned unbundled REC solicitation.

26. The annual solicitation process may be initiated by either an ALJ ruling or a ruling by the Assigned Commission to provide for added flexibility to the process.

27. It is reasonable to not require two ESPs, Praxair and Liberty Power Delaware, to file procurement plans because they do not serve any retail load.

28. In the absence of additional statutory analysis, it is not reasonable to grant Bear Valley Electric Service an exemption from filing annual procurement plans.

29. Unless otherwise addressed herein, all the motions requesting confidential treatment are consistent with Commission decisions and are granted.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1), the draft 2013 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 in the Ordering Paragraphs that follow.

2. Pacific Gas and Electric Company, Southern California Edison 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 mailing date of this decision pursuant to the RPS solicitation schedule adopted in Ordering Paragraph 7.

3. All future Renewables Portfolio Standard annual procurement plans filed pursuant to Pub. Util. Code § 399.11 *et seq.* must include a separate section addressing safety considerations.

4. 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.

5. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall provide information on contracts expected to expire through 2023 in all future Renewables Portfolio Standard Procurement Plans until otherwise directed by the Commission.

6. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed

with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall incorporate the modifiable Standard Term and Condition 2 (STC 2) adopted by this decision for use in the modifiable pro forma RPS ~~all~~ contracts for RPS procurement ~~signed~~ on or after January 1, 2014. After the same date, the STC 2 adopted by this decision shall also be incorporated into any Commission-approved non-modifiable form contract for RPS-eligible procurement if that form is used for procurement of a biomethane resource. The STC 2 adopted today supersedes the existing STC 2.

7. The following schedule is adopted for the 2013 Renewable Portfolio Standard (RPS) solicitation:

Schedule for 2013 Solicitation

Line No.	Item	No. of Days (cumulative)
1	Mailing of Commission decision conditionally accepting 2012 RPS Procurement Plans	0
2	G&E, SCE and SDG&E file final 2013 RPS Procurement Plans	14
3	PG&E, SCE, and SDG&E issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 24)*	24
4	PG&E, SCE, and SDG&E submit shortlists to Commission and Procurement Review Group	120
5	PG&E, SCE, and SDG&E file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	150
6	PG&E, SCE and SDG&E 2013 RPS RFO Shortlists Expire	485
7	PG&E, SCE, and SDG&E submit Advice Letters with contracts/power purchase agreements for Commission approval	TBD

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

8. 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 the efficient administration of the 2013 Renewables Portfolio Standard solicitation process.

9. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company are not authorized to include language regarding the use of non-zero integration cost adders for purposes of bid evaluation.

10. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) are authorized to include in their RPS bid solicitation protocols a requirement for a California Independent System Operator

Generation Interconnection and Deliverability Procedures (or Generation Interconnection Procedures) Phase II (or equivalent) study to bid into its 2013 RPS solicitation. Pacific Gas and Electric Company (PG&E) shall modify its final 2013 RPS Procurement Plan to include the same requirement. This directive applies to future RPS Procurement Plans filed by PG&E, SCE, and SDG&E.

11. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are not authorized to require shortlist exclusivity as part of the contract negotiating process. Shortlist exclusivity is not permitted in future RPS solicitations.

12. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to require sellers to deliver generation that meets an expected delivery profile and to pay sellers a lower price (or no price) if sellers are not able to deliver within certain parameters.

~~13. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company is not authorized to include a pro forma contract provision that requires buyer to agree to unlimited curtailment. The minor revisions proposed by Southern California Edison Company to the curtailment provisions are accepted. San Diego Gas & Electric Company offered no revisions to curtailment provisions.~~

14. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to include varying preferences.

~~15. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company is not authorized to include procurement for Portfolio Content Category 2 and 3 Renewables Portfolio Standard products to build and maintain an "adequate" bank.~~

16. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, the use of the Pacific Gas and Electric Company's Portfolio-Adjusted Value methodology, as modified to exclude contract term length adjustment <u>and to include debt equivalence</u>, is accepted for only the 2013 solicitation.

~~17. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company is not authorized to include a provision that requires the seller to bear all integration-related charges that are attributable to the seller's resource.~~

~~18. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plan to be filed with~~

~~the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) shall modify its 2013 RPS Solicitation Protocol and other parts of its 2013 draft RPS Procurement Plan, as necessary, to include a project development security equivalent of Southern California Edison Company's $90/kilowatt (kW) for baseload resources and $60/kW for intermittent resources for Portfolio Content Category 1 and 2 products.~~

19. In the final Renewables Portfolio Standard (RPS) Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) shall make public specific information redacted in its draft 2013 RPS Procurement Plan, unless any such aggregated data would include fewer than three individual RPS contracts~~doing so would reveal a single RPS contract price that would otherwise be covered by Decisions 06-06-066 and 08-04-023~~. Specifically, the information to be made public, to the extent it aggregates at least three contracts, is cited as follows:

Page 102
Page 109, Table 12-1, rows 1, 2, 5 and row 8 for 2017 and beyond
Page 110, Table 12-1, rows 1, 2, 5 and 8
Appendix 2, Table 1, rows 11, 12 and 14
Appendix 2, Table 2, rows 2, 3, 6, 11, 12, 14 (for 2017 and beyond), 16-26, 28-29 (for 2017 and beyond)

20. In the final 2013 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company is permitted, for only the 2013 solicitation, to incorporate a congestion cost adder into its least cost, best fit methodology for energy-only projects.

21. In the final 2013 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company is not authorized to include changes to its proposed 2013 RPS pro forma contract related to seller's bearing the risks of negative pricing for energy-only projects.

22. The 2013 Renewables Portfolio Standard (RPS) Procurement Plans filed by the smaller utilities, Bear Valley Electric Service and Liberty Utilities (CalPeco Electric) LLC are accepted and deemed final.

23. Pursuant to Pub. Util. Code § 365.1(c)(1) and Decision 11-01-026, the 2013 Renewables Portfolio Standard (RPS) Procurement Plans filed by electric service providers (ESPs) are accepted and deemed final, including, 3 Phases Renewables, Calpine PowerAmerica-CA, LLC, Commercial Energy of California, Consolidated Edison Solutions, Inc., Constellation NewEnergy, Inc., Direct Energy Business, LLC, Direct Energy Service, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC, Gexa Energy California, LLC, Liberty Power Delaware, LLC, Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Pilot Power Group, Inc., Praxair Plainfield, Inc., Shell Energy North America (US), L.P., Southern California Telephone & Energy, Tiger Natural Gas, Inc.

24. Praxair Plainfield, Inc. and Liberty Power Delaware, LLC are not required to file an annual procurement plan pursuant to § 399.12(a)(1) until retail load is served.

25. Bear Valley Electric Service's request for exemption from annual Renewables Portfolio Standard Procurement Plans is denied.

26. Unless otherwise addressed herein, all motions filed seeking confidential treatment of information set forth in the 2013 draft RPS Procurement Plans and final plans are granted.

27. On or before 14 days of the mailing date of this decision pursuant to the Renewables Portfolio Standard solicitation schedule adopted herein, PacifiCorp shall file an amended On-Year Supplement that includes information regarding its planned unbundled Renewable Energy Credit solicitation, including a pro forma contract.

28. 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 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement," dated November 4, 2013. 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 4th of November, 2013 at San Francisco, California.

/s/ KAREN KHAMOU

Karen Khamou
Manager, Renewable Energy Policy and Planning
Pacific Gas and Electric Company