BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
REPLY TO OPENING COMMENTS ON 2014 RPS PLANS
AND RELATED PROPOSALS

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In compliance with the Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2014 Renewables Portfolio Standard ("RPS") Procurement Plans, issued in this docket on March 26, 2014 (the "ACR"), Pacific Gas and Electric Company ("PG&E") submits this reply to parties' opening comments on the draft 2014 RPS Plans and the ACR's proposals regarding a renewable integration adder and the valuation of system capacity.[1/]

I. INTRODUCTION

Parties' opening comments on the draft 2014 RPS Plans focused primarily on two of the ACR's proposals. With regard to an integration cost adder, PG&E notes general consensus among parties on the need to establish an interim adder for use in the RPS Solicitation bid evaluation protocols and for continued work toward a California-specific integration cost methodology. PG&E responds below to the principles and methodologies proposed by parties and recommends the adoption of an interim adder for the 2014 RPS Solicitation based on the range of variable integration costs observed in other integration studies and utility-specific fixed integration costs. PG&E also recommends that the development of a permanent integration cost

1/ In an e-mail dated April 16, 2014 to the service list for this proceeding, Administrative Law Judge ("ALJ") DeAngelis granted a joint investor-owned utility ("IOU") request for an extension of three weeks to the schedule set forth in the ACR. Accordingly, the comments on new proposals and the draft RPS Plans are to be filed not later than July 30, 2014.

methodology be added to the scope of Phase 1B of the Long-Term Procurement Plan ("LTPP") proceeding and that each IOU be subsequently authorized to use the approved LTPP methodology to calculate specific renewable integration adders for use in the RPS solicitations as part of each annual RPS Plan update.

With regard to the valuation of system capacity in the RPS Solicitation, only the California Wind Energy Association ("CalWEA") supports requiring that IOUs attribute no system capacity value to bids in the 2014 cycle.[2/] Other parties, including PG&E, argue for the need to assume some capacity value.

While PG&E replies below to a number of the specific comments from parties on other aspects of PG&E's June 4, 2014 Draft RPS Plan (the "Draft RPS Plan"), PG&E continues to support the California Public Utilities Commission's ("Commission") past approach of "flexibility with accountability," under which it has "granted RPS-obligated utilities considerable flexibility in the way they satisfy RPS Program goals" in light of those utilities' legal obligations to comply the RPS requirements.[3/] Specifically, the Commission has described its approach to reviewing the RPS Procurement Plans as follows:

> Our responsibility includes accepting, rejecting or modifying IOU Plans (or updates to those Plans) before solicitations may begin. . . .We do not, however, write any Plan, [Integrated Resource Plan ("IRP")], or Supplement, or dictate with precise detail the specific language of any Plan, IRP or Supplement. Nor do we micromanage what is in the Plan, IRP or Supplement. Rather, each utility has considerable flexibility to develop and propose its own Plan, IRP, and Supplement. Our review is at a reasonably high level. Similarly, we do not take over the procurement process. Each utility is ultimately responsible for achieving successful procurement using its Plan, IRP or Supplement pursuant to, and consistent with, the RPS Program.[4/]

Consistent with this approach, and in light of the legal and policy arguments set forth below, the Commission should not require modifications to PG&E's Draft 2014 RPS Plan, should reject parties' calls for the plans to assume increased renewables procurement targets, and

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2/ *See* CalWEA Opening Comments at 9-10.

3/ Decision ("D.") 11-04-030 at 11.

4/ *Ibid.*

should not require changes in PG&E's Draft 2014 RPS Form Power Purchase Agreement ("PPA").

II. REPLY TO COMMENTS ON ACR PROPOSALS

This section of PG&E's reply addresses the opening comments on the ACR's proposals regarding integration costs and capacity valuation.

A. Renewable Integration Cost Adder ("RICA")

Of the parties that filed comments on the RICA, a majority recommended the Commission allow for an interim non-zero integration adder in this 2014 RPS planning proceeding.[5/] PG&E agrees with these parties and recommends the Commission make it a top priority in this proceeding to allow for integration costs to be explicitly considered beginning in the 2014 RPS Solicitation bid evaluation process.

Because the discussion of an integration adder may expand across multiple proceedings and be refined over time, PG&E offers the following implementation roadmap to help identify the steps involved and their inter-dependencies. The emphasis of this roadmap is to develop a RICA for use in the RPS Solicitation bid evaluation process.

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5/ *See* BrightSource Energy, Inc. ("BrightSource") Opening Comments at 5; Calpine Corporation ("Calpine") Opening Comments at 6; CalWEA Opening Comments at 27; Independent Energy Producers Association ("IEP") Opening Comments at 4; Ormat Technologies, Inc. ("Ormat") Opening Comments at 20; Southern California Edison Company ("SCE") Opening Comments at 3; San Diego Gas & Electric Company ("SDG&E") Opening Comments at 5.

Step	Action(s)	Time / Venue	Responsible Party
1	**Adopt interim RICA values**	2014 RPS Plan Proceeding	CPUC
2	**Adopt methodologies to calculate RICA values**	2014 LTPP[6/] Phase 1B	CPUC
2a	Propose methodologies for consideration		All stakeholders
2b	Publicly vet and refine methodologies		All stakeholders
2c	Approve methodologies to calculate RICA values		CPUC
3	**Calculation of RICA values as part of updating Least-Cost, Best-Fit ("LCBF") bid evaluation methodologies**	RPS Plan Proceedings (Annual)	Each IOU

Elaborating on the proposed roadmap, PG&E proposes first that the Commission adopt a set of interim RICA values in this 2014 RPS Plan proceeding. As discussed earlier in this section, parties signaled a clear need for the inclusion of non-zero adders for this round of LCBF evaluations. In a later section, PG&E offers a concrete approach to calculate a set of interim values.

Second, the development and approval of general RICA methodologies that can be used in future RPS Plan proceedings will likely require time and studies beyond the scope of this 2014 RPS Plan. Particularly, given the discussion on methodologies will require a good understanding of operating flexibility studies now under way in the 2014 LTPP Phase 1A proceeding, PG&E continues to believe the appropriate venue to further refine and discuss the various proposals is in Phase 1B of the 2014 LTPP.

Finally, the calculation of RICA values should become part of the LCBF process and be performed by the IOUs using the Commission-adopted methodology. PG&E believes this is the only logical approach as the purpose of this RICA is to help evaluate resources bid into RPS

6/ LTPP refers to the Commission's Long-Term Procurement Planning proceeding.

solicitations. As a result, this calculation must be integrated within the LCBF process and be performed as part of the update in each annual RPS Plan of the LCBF methodology. Furthermore, the RICA calculation should be aligned with the energy and capacity valuations; when conditions change in the energy and capacity markets, these values should be adjusted accordingly.

1. Parties generally agree on three key principles to calculate an integration adder.

Of the parties that offered potential methods or general principles to use in calculating a RICA, there is general agreement on three principles:

a) **Integration costs should include both variable and fixed costs** – BrightSource, Calpine, CalWEA, Ormat, PG&E, SCE, and SDG&E provided the following lists of fixed and variable costs that should be considered in an integration adder.[7/]

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7/ Large-Scale Solar Association ("LSA") did not provide specific recommendations; *See* comments of LSA at 10 ("LSA does not have a specific recommendation at this time as to what form the integration adder should take.")

	Brightsource[8/]	Calpine[9/]	CalWEA[10/]	Ormat[11/]	PG&E[12/]	SCE[13/]	SDG&E[14/]
Variable Costs							
Increased Ancillary Services ("AS") costs	X				X		
Flexible Ramping Product ("FRP")	X	X	X	X			
Regulation		X		X			
Load following reserves				X		X	
Additional start-ups, cycling, and maintenance	X			X	X	X	X
Fixed Costs							
For incremental existing Flexible Resource Adequacy ("Flex-RA") capacity	X	X	X	X	X	X	
For incremental new flexible capacity needed			X	X	X	X	X

b) **Integration costs exists even if the system shows no need for new flexible resources** – Brightsource, Calpine, CalWEA, LSA, Ormat, PG&E, SCE, and SDG&E commented that an integration

8/ *See* BrightSource Opening Comments at 4.

9/ *See* Calpine Opening Comments at 5.

10/ *See* CalWEA Opening Comments at 19 (overview of costs to consider), at 20 (FRP), and at 22 (Flex-RA).

11/ *See* Ormat Opening Comments at 19 (providing a much longer list of variable and fixed costs to consider; PG&E lists here the subset of costs identified by Ormat that are in common with those proposed by other parties).

12/ *See* PG&E Opening Comments at 2.

13/ *See* SCE Opening Comments at 3.

14/ *See* SDG&E Opening Comments at 5.

adder should include the appropriate fixed and variable costs, even if the system does not show a need for new flexible resources.[15/]

c) **An integration adder should be calculated based on a time horizon over the entire contract period –** Calpine, Ormat, and PG&E recommended calculating a RICA based on the time period of each contract.[16/] CalWEA appeared to have offered a similar recommendation, except that the calculation of integration costs would be performed at less granular time intervals (i.e., at two distinct levels of RPS penetration of 33% and 40%).[17/] BrightSource, SCE, and SDG&E did not comment on this topic.[18/]

PG&E believes these three principles form an appropriate foundation for the discussion of an integration adder, both in the interim and in the longer term.

2. Parties' comments offer two general frameworks to calculate a RICA, and identify the LTPP proceeding as an appropriate venue for further discussion.

In terms of establishing a framework for calculating an integration adder, most parties agree that a RICA needs to include both variable and fixed costs. Furthermore, parties generally agree that in the near term, the fixed cost portion can be derived based on the Flex-RA requirements established by the Commission. However, parties differ on how the variable costs portion should be calculated and offered two general methods.

15/ *See* Brightsource Opening Comments at 10; Calpine Opening Comments at 13; CalWEA Opening Comments at 30; LSA Opening Comments at 13; Ormat Opening Comments at 30; PG&E Opening Comments at 12; SCE Opening Comments at 6; SDG&E Opening Comments at 10.

16/ *See* Calpine Opening Comments at 9; Ormat Opening Comments at 25; PG&E Opening Comments at 11.

17/ *See* CalWEA Opening Comments at 28 (implying that integration costs would only be calculated at RPS penetration levels of 33% and 40%); *id.* at 29 ("The adder should apply to all projected procurement under each proposed contract").

18/ LSA did not oppose this principle, but noted that it may be difficult to estimate an integration costs over multiple years. LSA Opening Comments at 10.

Calpine, CalWEA, and SCE offered a bottoms-up approach.[19] It breaks integration cost into different cost components, estimates each individual cost component, and then sums all the components to derive at a total integration cost.

Ormat and PG&E, in contrast, outlined a top-down, holistic approach.[20] This approach involves calculating a suite of integration costs in aggregate by comparing production simulation results from cases that would isolate the integration costs of incremental renewable resource additions.

PG&E prefers the holistic approach because it captures the interactions between the various cost components of the renewable integration adder. These interactions should not be ignored. For example, the amount of FRP procured may have an effect on the amount of regulation used to balance the intra-hour fluctuations on the system; the amount and type of operating reserves withheld to meet anticipated ramping needs may also affect the remaining resources available for energy dispatch. A bottoms-up approach that would calculate individual cost components does not consider any interactions between the cost components and may consequently lead to a RICA that is higher or lower than the actual cost. While it may be possible to sort out these interactions with the bottoms-up approach (through, *e.g.,* calculating all the possible interactions and then manually removing them from the individual cost components), it is much simpler under a holistic approach that models the entire system.

Nevertheless, PG&E believes the discussion around these two methods marks a good starting point for the development of a rigorous framework to calculate a RICA. Given the nature of this analysis, which involves an examination of the flexibility needs of the system under various scenarios over different periods in time, PG&E agrees with Ormat and the Union of Concerned Scientists ("UCS") that Phase 1B of the 2014 LTPP is the appropriate public venue

19/ *See* Calpine Opening Comments at 10-12; CalWEA Opening Comments at 19 (outlining the short, medium, and long run cost components); SCE Opening Comments at 3.

20/ *See* Ormat Opening Comments at 25; PG&E Opening Comments at 3-6.

in which to develop a final RICA methodology.[21/] In general, most parties agree that the LTPP is the most appropriate, existing proceeding that could inform or help refine an integration adder.[22/]

3. In establishing an interim RICA, the Commission should rely on both publicly-available information from other balancing authorities and cost projections for integration costs within California.

While there is general agreement that an interim adder is needed and can be developed now, there is no clear agreement on what that interim adder value should be, nor how it should be calculated.

Some parties presented indicative values by estimating costs for individual components of the integration adder based on existing California market data.[23/] Other parties referenced integration studies from other jurisdictions.[24/] PG&E recognizes that the difference in resource mix and renewable penetration level between balancing areas can make it difficult to compare results across regions, thus we are not opposed to alternative approaches to develop an interim adder. However, PG&E believes any proposed interim value must be able to pass two basic tests for reasonableness: 1) the methodology used to develop an interim RICA must be consistent with the three principles listed in the earlier section; and 2) the proposed interim value must be reasonable when compared against integration costs from existing studies conducted for California and neighboring regions.

21/ *See* Ormat Opening Comments at 27; UCS Opening Comments at 5.

22/ *See* BrightSource Opening Comments at 9 (LTPP can help inform the RICA); Calpine Opening Comments at 12 (LTPP can help refine RICA values); CEERT Opening Comments at 25 (LTPP work can inform the RICA); LSA Opening Comments at 10 (RICA should be updated in concert with the LTPP cycle); SDG&E Opening Comments at 9 (RICA should leverage results from the LTPP).

23/ *See* Calpine Opening Comments at 5 (which presents estimated regulation requirement and costs); CalWEA Opening Comments at 22 (illustrating projected FRP costs based on 2012 Flexible Ramping Constraint data).

24/ *See* Ormat Opening Comments at 29-30 (referencing integration studies conducted by GE Energy and Exeter Associates, and by the U.S. Department of Energy); PG&E Opening Comments at 7 (referencing multiple integration studies by balancing authority areas in the Western Electricity Coordinating Council ("WECC") region); SCE at 3 (referencing National Renewable Energy Laboratory's Western Wind and Solar Integration Study Phase 2 study).

a. PG&E disagrees with LSA's and CalWEA's assertion that an interim value can be calculated based solely on existing CAISO market data

One of the three key principles discussed earlier is that an integration adder should be calculated based on a time horizon over the entire contract period. This is consistent with the calculation of energy and capacity values in the LCBF determination.

Accordingly, PG&E disagrees with the assumption that current or near-term California Independent System Operator ("CAISO") costs and requirements for integrating the existing portfolio of delivering RPS-eligible resources is good enough to calculate a RICA for a 10-15 year contract that starts in 2020. Specifically, PG&E disagrees with LSA's recommendation that an interim adder be based on current CAISO costs and CalWEA's proposal that for an interim adder, the medium-term integration costs (*i.e.*, those based on flex-RA costs) can be assumed to be zero.[25/] PG&E agrees with CalWEA that the cost to procure new flexible capacity is potentially the largest integration costs, but disagrees with the implication that the Commission can rely on the input assumptions for the 2014 LTPP to conclude that there is no long-term integration costs without seeing the results of the analysis for 2024.[26/]

Past CAISO integration studies make clear that the CAISO expects increases in load following requirements, and the Commission has required procurement of flexible capacity in the 2015 RA compliance cycle.[27/] The magnitude of the load following (*e.g.*, FRP) and flex-RA capacity requirements are directly related to the amount of load and renewable resources in the system; changes in system condition will dictate a change in the requirements. For example,

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25/ *See* LSA Opening Comments at 12; CalWEA Opening Comments at 23.

26/ *See* CalWEA Opening Comments at 24-26.

27/ California Public Utilities Commission, "R.12-03-014: LTPP Track II Workshop – Operating Flexibility Modeling Results," Aug. 26, 2013, at slide 25 (providing CAISO regulation and load following requirements for the 2012 LTPP Base Scenario and noting that load following under the 33Base scenario is projected to be roughly three times the regulation requirement in terms of MW) (available at http://www.cpuc.ca.gov/NR/rdonlyres/C856A74F-1B6A-45A4-8272-98883F909583/0/CAISOOperatingFlexibilityModelingResults.ppt)); CAISO, "Final 2014 Flexible Capacity Needs Assessment," May 1, 2014 (providing CAISO Flex-RA requirements for 2015) (available at http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf).

under the current flex-RA capacity method *(i.e.*, based on a three-hour ramping need), the annual CAISO flex-RA requirement for 2015 is 11,212 MW.[28/] The same requirement in 2022, after considering the expected change in load and renewable resources, is estimated to be 14,680 MW, an increase of 30%.[29/] It is inappropriate to assume that such a change in requirement will have no impact on market prices for flexible capacity. Conversely, it is only reasonable to assume that to the extent a utility has an open position for flex-RA capacity, a portion of the premium paid for such capacity above the costs to obtain generic RA capacity be included as part of the interim adder.

In their comments, both Calpine and CalWEA acknowledge the possibility that over the term of a particular RPS-eligible contract, a utility may have an open position for flexible capacity and the utility may incur additional cost to fill these positions;[30/] PG&E agrees with this view.

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b. CalWEA's proposed interim adder cost is unrealistic when compared to integration costs from existing studies.

By failing to consider costs over the term of a contract and the interactions between one CAISO market product with the rest of the energy and ancillary services market, CalWEA's

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28/ *See* CAISO, "Final 2014 Flexible Capacity Needs Assessment," *supra*, at 3 (noting that the requirement is set by maximum ramping need in December).

29/ PG&E derived this estimate based on hourly load, wind, and solar data from the 2012 LTPP base case, and then identifying the maximum 3-hour ramping need (*i.e.*, consistent with how the CAISO sets the Flex-RA requirement).

30/ *See* Calpine Opening Comments at 11 ("[I]f fulfilling Flexible RA procurement requirements involves securing additional capacity from resources that are not already procured as system or local RA, prevailing prices for system RA of approximately $2/kW-month might reasonably reflect the cost of such additional capacity."); CalWEA Opening Comments at 23 ("Designating some of the existing RA capacity as flexible RA capacity may or may not entail additional payments to such resources, depending upon the utilities' contract terms for their existing resources.").

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proposed interim value is unreasonably low when compared against numbers from existing integration studies. Specifically, CalWEA proposed a value that is made up of: 1) short-term costs that are based solely on the Flexible Ramping Constraint ("FRC") costs from the first quarter of 2012; 2) medium-term costs that are based on the assumption that the cost for flex-RA is zero; and 3) long-term costs that are based on the assumption that the need and cost for new flexible capacity is zero. Taken together, CalWEA proposes the following interim integration costs: $0.13/MWh for wind and $0.39/MWh for solar.[31/] These assumptions are patently unreasonable and are not supported by any independent data. Below, PG&E provides integration costs adopted by other balancing area authorities ("BAAs") in the WECC region. This is the same list of costs included in PG&E's opening comments,[32/] but presented here in terms of fixed and variable costs.[33/] The values proposed by CalWEA would fall outside of even the most extreme outliers, and is clearly inappropriate for an interim RICA.

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31/ *See* CALWEA Opening Comments at 22 (on FRC costs), 23 (medium-term cost), 25 (on long-term cost).

32/ *See* PG&E Opening Comments at 7–8 (providing citations to support the data provided in the tables).

33/ In general, BAAs that use integration costs to allocate balancing costs to exporting entities tend to base the RICA on fixed costs; BAAs (vertically integrated utilities) that use integration costs in their IRP planning process tend to base RICA on variable costs. The solar integration cost of $0.82/MWh used by BPA is excluded from this list because it was based on a simple percentage of BPA's wind integration costs and not on a separate integration study.

	Variable Costs ($/MWh)											Fixed Costs ($/MWh)											
Wind	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	**Wind**
APS				3.3												2.86 - 4.70							BPA
PSCo					3.68 - 4.09											3.03 - 6.07							Puget
Avista		1.3																					
BC Hydro										9.1													
Idaho Power										8.06 - 19.01													
N.W.E. (Montana)					1.02 - 7.51																		
PacifiCorp				2.6																			
Portland General					4																		
	Variable Costs ($/MWh)											**Fixed Costs ($/MWh)**											
Solar	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	**Solar**
APS			2.00 - 3.00									*No study available*											
PSCo				1.25 - 6.06																			

c. PG&E recommends a hybrid approach based on publicly available information and cost projections over the contract period.

Considering the information parties provided in their comments regarding an interim value, PG&E recommends the Commission allow the utilities to employ an interim adder in the 2014 RPS Solicitation based on the range of variable integration costs observed in other integration studies, and a utility-specific fixed integration costs described below.

a) Variable or operating integration costs of $4/MWh for wind and $3/MWh for solar. These values are based on the range of variable costs presented above from $ 1.02/MWh to $19.01/MWh for wind and $ 1.25/MWh to $6.06/MWh for solar;

b) Fixed integration costs calculated by each IOU based on its portfolio need to secure additional capacity from resources that are not already procured to meet its flexible and non-flexible RA requirements over the contract period.

While PG&E's forward price forecasts for capacity and its open position for capacity are confidential, PG&E proposes to calculate the interim renewable integration fixed cost adder as the product of:

a) The monthly increase (or decrease) in flexible capacity requirement due to the increment of wind or solar being considered for the solicitation, based on the most recently adopted Commission RA decisions.[34/] This incremental requirement will be calculated based on the overall system flexible capacity requirement and then applying the percentage contribution from wind or solar; the methodology to determine both the flexible capacity requirement and the percentage contribution are defined in the CAISO's Flex-RA study.[35/]

b) The projected monthly price (which can be zero or positive) for flexible RA, which is the same parameter used in the calculation of capacity benefits.

For illustration purposes only, if the monthly cost of flexible capacity in the month of November of 2020 is $2/kw-month and the increase due to an increment of wind is 1% of installed wind capacity, and 40% of installed solar capacity, the corresponding fixed integration costs for this month would be $0.10/MWh for wind and $3.60/MWh for solar, assuming a 30% capacity factor for each technology.

4. Limit the scope of the initial RICA analysis and then broaden and refine it over time.

In their comments, Calpine, CalWEA, and Ormat commented that for the time being, the integration adder should first focus on a differentiation by technology types.[36/] PG&E agrees with this view.

34/ See, e.g., Proposed Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program," filed May 27, 2014 in Rulemaking 11-10-023.

35/ See CAISO's 2014 Flexibility Needs Assessment (http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf)

36/ *See* Calpine Opening Comments at 8; CalWEA Opening Comments at 28; Ormat Opening Comments at 24.

It is important to strike a balance between the level of granularity to be included in an adder and the effectiveness of the results it produces. PG&E recommends that additional granularity, such as the location-specific impacts on integration cost as suggested by BrightSource and LSA,[37/] be analyzed in future RPS proceedings that refine the initial RICA methodology. Limiting the initial scope of the RICA effort will help to avoid the complexity of the issue from preventing reasonable initial efforts to capture integration costs in the evaluation process.

PG&E also notes that CEERT's recommendation that the Commission apply integration adders to conventional resources as well as RPS-eligible resources is beyond the scope of this proceeding, which focuses solely on the procurement of renewable resources.[38/] Furthermore, because of their higher variability and forecast uncertainty, wind and solar renewable resources generally have greater integration costs than other resources, and so the Commission's priority should be in approving a RICA for these resources.

5. Reponses to the Commission's "Questions to Guide Reply Comments" regarding the establishing of a RICA.

(1) There is general consensus among parties that an integration adder should be dynamic, updated frequently and differ based on technology and location. Furthermore, most parties agree that an adder should only include the indirect costs associated with integrating variable energy resources such as costs associated with regulation, ramping and cycling. If this is the case, should the term "integration adder" be changed to reflect these agreed upon attributes if what ends up being calculated are unique costs for each technology based on changes in electrical systems' portfolio mixes over time? What is your recommendation and what standard "term" and "definition" do you believe the CPUC should adopt?

PG&E is open to other suggestions. However, PG&E believes the term integration cost adder is appropriate and does not see any clear benefits of using alternative terms. Furthermore,

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37/ *See* BrightSource Opening Comments at 7; LSA Opening Comments at 11.

38/ *See* CEERT Opening Comments at 24.

PG&E notes that the present comments focus only on generation-related integration costs. There may be additional transmission and distribution integration costs not currently captured in interconnection studies that need to be considered as the Commission's effort to address integration costs evolves.

> (2) *If integration adders were developed in the LTPP Proceeding, would updating the adders best be achieved by including that as part of the biennial LTPP process? If not, what frequency and manner would be ideal? How would those results be introduced into the LTPP record?*

Please see discussion in Section II.A., above, regarding a proposed RICA roadmap. While the general framework or methodology should be refined and adopted as part of the LTPP, PG&E believes that the RPS Plan proceeding in this docket is the appropriate place to calculate the RICA for use in RPS Solicitation bid evaluations. As part of each annual update to an IOU's LCBF criteria, the IOU can calculate the RICAs using the methodology adopted in the LTPP and energy and capacity assumptions that are aligned with market valuations reflecting updated markets conditions.

> (3) *Three general approaches to calculating integration adders were identified by parties – 1) using values from publicly available studies, 2) using market-based cost data from CAISO's regulation and upcoming flexible capacity markets, and 3) using the operational flexibility studies currently scoped in the LTPP proceeding to inform the development of integration adders. Please comment on the advantages and disadvantages of each approach and recommend a procedural framework for implementing your preferred approach. If your recommended framework utilizes more than one approach please be specific regarding the procedural steps and timeline that the CPUC should follow in developing integration adders.*

PG&E's understanding is that parties recommended two general methodologies, which are listed as 2 and 3 in this question. Please see the discussion in Section II.A.2., above, regarding a framework for a comparison of the two. PG&E believes approach 1 listed in the question was brought up in the context of developing an interim adder. PG&E supports using publicly-available studies for that purpose and recommends specific steps to calculate an interim adder (see discussion under Section II.A.3, above).

> (4) *Do you think it is important for the Commission to determine a methodology for the development of integration adders as well as calculate the values to be used in LCBF? Or is it more appropriate that the IOUs be responsible for calculating integration cost adders based on the methodology developed by the CPUC? Please recommend your preferred approach by weighing the strengths and weaknesses of allowing for IOU-based values. In considering your recommendation, how important is it that the values calculated be verifiable by parties?*

PG&E recommends that the Commission review and adopt the methodology to calculate RICA values in the LTPP Phase 1b proceeding and that the IOUs be responsible for calculating RICA values to be used in the LCBF methodologies as part of future RPS Plan proceedings. Please see the discussion under Section II.A., above, regarding a roadmap for RICA development going forward. PG&E supports a process in which the RICA framework and methodologies are thoroughly vetted in the public, and the implementation of these specific frameworks be carried out by the IOUs based on their own assessment of the future in the same way other elements of the LCBF evaluation is determined.

> (5) *Do you think it is important for the CPUC to adopt a methodology to calculate integration adders in time for the 2014 RPS Solicitation beginning in early 2015? If so, can any of the three general approaches mentioned in Question 3 meet this objective while also providing reasonable and defensible cost estimates? In addition, do you believe integration adders, if calculated using one of the three approaches, will be significant enough to alter procurement decisions?*

Yes, PG&E believes that the Commission should use the basic principles defined in Section II.A.1, above, to adopt interim RICA values for use in the 2014 RPS Solicitation. PG&E also recommends that the Commission further refine and adopt the methodology in the 2014 LTPP Phase 1B proceeding.

> (6) *In its comments, PG&E provided a framework for calculating integration adders using production cost modeling. If parties agree that production cost modeling should be utilized to determine the costs associated with integrating renewables, do you agree with the framework that PG&E has proposed? Are there any modifications to the framework that you would make? If so, provide a modified framework in your response.*

PG&E has no modifications to propose at this time.

> (7) *Integration costs may rise as the saturation level of renewable resources increases over time. If production cost modeling is used to assist in developing integration adders, what level of renewable saturation should be assumed and what is your rationale?*

PG&E believes that to the extent the integration adders are intended to capture long-term renewable integration costs, it should be calculated based on the current RPS requirements and the timeline for meeting those requirements set forth in the RPS statute and implementing Commission decisions.

> (8) *In its comments, CalWEA provided a framework for calculating the short-term, medium-term and long-term costs associated with renewable integration. Please comment on the practicality of this framework and whether you think it could meet the objective of developing integration adders that are reasonable and defensible. What refinements need to be made to the proposed framework for it to achieve the stated objectives?*

Please see the discussion in Section II.A.2., above, for a comparison of CalWEA's framework with the alternative proposed by PG&E. Also, please see the discussion in Section II.A.3. regarding establishing an interim RICA value for why it is inappropriate to use only current/existing data to support future projections.

B. System Capacity Valuation in the RPS Solicitation

PG&E observes that there is near consensus among parties that there should be a positive capacity value attributed to renewable resources that are either fully or partially deliverable. To the extent that renewable resources contribute to meeting RA requirements, the value of that capacity should continue to be taken into account in the LCBF valuation process. PG&E agrees with the comments of LSA that "it is misguided for the Commission to develop a price for a market-based product based on study assumptions."[39/] As many parties note, there is a positive capacity value to fully or partially deliverable resources irrespective of whether or not there is an incremental system need. To the extent an IOU can count the capacity from a renewable resource toward its RA obligation, that IOU obviates the need to procure that capacity elsewhere.

PG&E agrees with parties that advocate for basing capacity valuation on Effective Load Carrying Capacity ("ELCC") values for net qualifying capacity ("NQC"), rather than basing NQC on the 70% exceedence method. In fact, PG&E has been using internally-developed ELCC values as the basis for NQC for the past several years in its RPS solicitations. Assuming the Energy Division's analysis of ELCC values produces reasonable results, PG&E would consider using those values in its LCBF methodology.

III. REPLY TO COMMENTS ON THE DRAFT 2014 RPS PLANS

A. PG&E's Draft RPS Plan Should Not Be Revised at This Time to Assume Renewables Procurement beyond the RPS Compliance Targets.

Several parties representing renewable generation developers commented that the IOUs' RPS Plans should either consider or seek authorization for procurement in excess of the current RPS Program requirements.[40/] In general, these parties refer to the enactment of Assembly Bill ("AB") 327, which provided the Commission with the authority to increase the RPS requirements. CEERT also argues that the RPS Plans insufficiently account for the status of renewables as one type of "preferred resource" in the State's "Loading Order" policy.[41/]

PG&E disagrees that its Draft 2014 RPS Plan must be modified to consider additional renewables procurement above the current RPS targets or to meet other operational needs. The purpose of the RPS Plans, and, indeed, of the Commission's rulemaking to implement the RPS

39/ LSA Opening Comments at 5.

40/ *See* Center for Energy Efficiency and Renewable Technologies ("CEERT") Opening Comments at 4-17; Coalition of California Utility Employees ("CUE") Opening Comments at 3; Iberdrola Renewables, LLC ("Iberdrola") Opening Comments at 2; IEP Opening Comments at 2; LSA Opening Comments at 2-3.

41/ CEERT Opening Comments at 10-13.

statute, are to ensure that retail sellers achieve the statutory RPS compliance targets. Contrary to parties' statements, PG&E views these targets as a minimum, statutory "floor" on the procurement of renewable energy. PG&E has always been able to voluntarily seek Commission approval to procure renewable energy in excess of the RPS requirements. However, the RPS planning process is designed to result in the least-cost, best-fit procurement of RPS-eligible products in order to ensure that each retail seller complies with existing RPS requirements.

AB 327 simply allows, but does not require, the Commission to raise the RPS targets, and PG&E would revise its RPS Plan on a going-forward basis if and when the Commission exercises that authority. Because the Commission has not yet exercised its AB 327 authority, PG&E's Draft 2014 RPS Plan appropriately remains focused on cost-effective compliance with the existing RPS requirements set forth in D.11-12-020.

Additionally, the identification of additional procurement need, which may be met through preferred resources, to meet local reliability or other non-RPS needs is outside the scope of the RPS Plan and proceeding. If the Commission in the future authorizes PG&E to procure additional RPS-eligible resources in order to meet non-RPS operational or reliability needs, as it has for SCE and SDG&E in the LTPP proceeding, then PG&E would include the planned procurement of those resources in its RPS Plan since the procurement would impact PG&E's remaining RPS-related procurement need going forward. However, the Commission has not yet authorized such non-RPS related procurement of renewables for PG&E, and it is beyond the scope of the RPS proceeding to conduct integrated long-term procurement planning to identify any such need. Accordingly, PG&E's Draft 2014 RPS Plan cannot and should not assume either higher RPS targets or the procurement of renewables for non-RPS needs.

CEERT's recommendations, if adopted, would require PG&E to assume some speculative amount of additional RPS-eligible procurement will occur in the future in order to meet needs other than RPS compliance. Such an assumption would distort PG&E's actual Renewable Net Short ("RNS") calculation by suggesting that PG&E needs less RPS procurement in order to meet the RPS compliance targets. This could lead to a near-term reduction in authorized RPS procurement, with the effect that PG&E could find itself at higher risk of non-compliance in the future or that its customers will face potentially higher costs of compliance because of the need to make up deficits in procurement at a later date if the non-RPS renewables procurement was never in fact authorized. The Commission should avoid speculation and assumptions like this that distort the RNS, which is useful tool designed to measure a retail seller's actual need in order to achieve RPS compliance. Only after specific authorizations are made in the LTPP or other proceedings to procure RPS-eligible products to meet operational or reliability needs should those authorizations be imported into the RPS Planning process. Because the Commission has not yet authorized such procurement for PG&E, CEERT's argument should be rejected.

B. The Commission Should Approve PG&E's Draft 2014 RPS Form Agreements and Solicitation Protocol without Modification.

The Commission has stated a preference in past RPS planning cycles for retail sellers and generators to negotiate contract terms so that the Commission can review a negotiated PPA in its totality. PG&E agrees that any attempt to negotiate a pro forma agreement in a multi-stakeholder regulatory proceeding where each party and specific project will prefer different terms and conditions is likely to be impractical and will lead to major delays in the regulatory and procurement processes. Fortunately, there is no need to reach consensus on a form agreement since, as the Commission has noted, "[t]he pro forma agreements serve as the *starting point* for negotiating a final agreement between a seller and utility."[42] Except for certain non-modifiable terms and conditions, which are consistent across all pro forma and executed RPS agreements, the RPS Form PPA is meant to be modified as necessary and in the mutual interest of the parties to a specific transaction to ensure it results in the greatest value and an appropriate risk allocation.

42/ D.12-11-016 at 29-30 (emphasis added).

Accordingly, PG&E responds here generally to the small number of specific comments parties submitted regarding terms and conditions in PG&E's Draft 2014 RPS Form PPA (the "RPS Form PPA"),[43/] but it expects to discuss these proposals more specifically with parties during the negotiation process following shortlisting. During that negotiation, developers are able to propose specific changes to the 2014 RPS Form PPA that they believe are necessary for purposes of financing and constructing their projects. Proposed changes to the RPS Form PPA can then be evaluated against all other bids and, if an IOU and the developer reach an agreement, that executed agreement, with any changes to the Form PPA indicated, will be submitted to the Commission for its review of the PPA in its "totality," i.e., with consideration of the material changes made to the form agreement.[44/]

1. PG&E's contract provisions related to economic dispatch of resources provide significant optionality for generators.

IEP supports the approach of SCE to ensuring adequate operational flexibility of RPS resources.[45/] As summarized by IEP, SCE offers bidders the option of offering either zero or 50 hours of unpaid economic curtailment and the further option of making up for paid curtailment at the end of the delivery term, for a total of four combinations of these options.[46/] LSA suggests, however, that this optionality might overly complicate the bidding process.[47/]

PG&E is not opposed to allowing sellers to offer 50 hours of unpaid curtailment. However, it is not clear how that would benefit Sellers or customers. Including any hours of unpaid curtailment is likely to result in more curtailment than if the first hour is paid. The Seller would need to price that unpaid curtailment into the offer, likely increasing the contract price (in other words, the provision is for "prepaid" rather than "unpaid" curtailment).

43/ The RPS Form PPA may be found in Appendix H of PG&E's June 4, 2014 Draft 2014 RPS Plan.

44/ *See* D.12-11-016 at 30.

45/ Opening Comments of IEP at 4-5 (summarizing the specific four options offered by SCE's pro forma PPA).

46/ *Ibid.*

47/ LSA Opening Comments at 3.

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PG&E notes that each of SCE options includes the potential for unlimited paid buyer curtailment, similar to the stated preference in PG&E's Draft 2014 RPS Plan.[48/] SCE's four options also include unlimited unpaid curtailment if ordered by the CAISO or the applicable transmission owner, consistent with PG&E's RPS Form PPA.

PG&E's approach to economic dispatch and operational flexibility in its Draft 2014 RPS Plan matches well with IEP's desire for optionality. Under PG&E's approach, Sellers are allowed to bid, at the Seller's discretion, both the number of hours of curtailment and the curtailment price, which may or may not be the same as the PPA price. Given this optionality and PG&E's stated preference for more operational flexibility, Sellers are free in their bids to propose the greatest volume of economic dispatch rights that each Seller believes it can finance and deliver.

PG&E's approach to this issue also accommodates adequately CalWEA's suggestion that the Commission direct PG&E to compensate sellers for the after-tax value of production tax credits ("PTCs") for energy that would have been generated but for the buyer-directed (economic) curtailment.[49/] The Commission need not require this outcome since PG&E's Draft 2014 RPS Form PPA already allows for Sellers to specify a price for deemed-delivered energy, which may include the price of foregone PTCs. The deemed delivered energy price may be higher or lower than the contract price, and no reason is required. The seller may choose a higher deemed-delivered energy price to compensate for lost PTCs, or may choose a lower deemed delivered price to reflect operational savings that result when the project is not dispatched. That deemed-delivered price is factored into the net market value calculation as part of PG&E's evaluation of the bids. In order to minimize future contract disputes/uncertainty, PG&E requires the Seller to provide a specific deemed delivered energy price (*e.g.* contract price

48/ Note that PG&E's 2014 Draft RPS Form PPA does not require unlimited economic dispatch rights, but rather allows each bidder to specify the number of economic curtailment hours available and the price for curtailed deliveries. However, PG&E's LCBF criteria are designed to prefer, all other factors equal, projects that provide more operational flexibility.

49/ CalWEA Opening Comments at 4. *See also* Iberdrola Opening Comments at 4.

+ $30/MWh) rather than something that must be debated in the future, such as the exact amount of lost tax credit.

Because PG&E's proposed provisions related to economic dispatch and operational flexibility adequately address parties' needs for flexibility and ability to secure financing, the Commission should approve the Draft RPS Plan without modification.

2. The Commission should not require that all automated curtailment instructions be treated as economic curtailment.

The Commission should reject CalWEA's suggestion that the Commission require all IOUs to clarify that automated curtailment instructions will be deemed buyer-directed economic curtailment.[50/] CalWEA's argument focuses on the principle that there should be a distinction between economic curtailment and non-economic curtailment.[51/] PG&E supports this principle, and its RPS Form PPA clearly distinguishes a Curtailment Order, which is directed by the CAISO, Participating Transmission Owner ("PTO") or Reliability Coordinator, from a Buyer Curtailment Order, which is directed by PG&E, and may be for economic reasons. Under PG&E's RPS Form PPA, Sellers are compensated for deemed delivered energy which would have been produced, but for the Buyer Curtailment Order.

However, the Commission should not confuse the definition of a curtailment order with the means with which it is transmitted. The CAISO's scheduling and dispatch is now done on 5 minute intervals. As a result, the project schedule will be transmitted via electronic signal. PG&E's RPS Form PPA requires the Seller to have the appropriate technology installed to receive and respond to those 5 minute operational instructions. The final schedule conveyed to Seller may be less than what the Seller is capable of generating. This may be because there is a reliability issue (for example, a CAISO Curtailment Order), or because PG&E's economic bid was not accepted (Buyer Curtailment). PG&E's PPA requires the Seller to respond regardless of the reason, and it includes penalties for non-compliance. In the settlement process, Buyer and

50/ *See* CalWEA Opening Comments at 6.

51/ *Id.* at 7.

Seller will have enough information to understand the reason for the schedule, and the Seller will be compensated for all buyer-directed curtailment. The CPUC should not blur the line between these two types of curtailments by requiring compensation for any CAISO curtailment orders that are transmitted via automatic dispatch system.

3. The Commission should not require all IOUs to use a single set of Time-Of-Delivery ("TOD") factors.

CalWEA supports SCE's proposal to use a single set of TOD factors and encourages the Commission to direct the other two IOUs to follow suit.[52/] CalWEA suggests that because the Resource Adequacy ("RA") benefit is already valued through the capacity component of the net market value calculation, assigning higher TOD factors to a deliverable project rewards deliverable projects twice for the same attribute.

PG&E disagrees with CalWEA that its proposed TOD factors result in double-counting of the capacity benefits of a deliverable project. PG&E's TOD factors simply align the RA capacity value PG&E receives from the Seller with the payment to the seller for that RA capacity. PG&E acquires RA capacity in order to meet peak reserve requirements. It is reasonable to pay for that capacity during that peak period.

The fact that PG&E attributes capacity value to deliverable resources in the net market value calculation of its bid evaluation methodology does not lead to double-counting of capacity. Rather, use of the TOD factors for fully deliverable resources to calculate capacity value ensures that resources are attributed value for the extent to which they are expected to meet peak reserve requirements.

PG&E fails to see any need to treat energy and capacity value differently in bid evaluation. With respect to energy value, PG&E considers how energy value differs over the course of the year, month, day and hour. In turn, PG&E pays a TOD-adjusted PPA price for that energy. CalWEA's argument would seem to suggest that PG&E should eliminate TOD factors

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52/ CalWEA Opening Comments at 10-11.

for energy as well as TOD factors for RA capacity since the hourly value of energy is also included in the net market value calculation. However, as with RA capacity, ignoring the time-differentiated value of energy deliveries would create a disconnect between the value attributed to bids and the actual value a resource is expected to provide to PG&E's customers.

Having two sets of TOD factors does not create unnecessary complexity and uncertainty in the market with respect to expected contract payments, as CalWEA suggests.[53/] Sellers know which TOD factors will apply when they sign the PPA, and they consider the TOD factors when they propose a contract price. There is no uncertainty as to the payment that will be received, other than uncertainty associated with generation output. The Commission should not require PG&E to distort the outcome of its bid evaluation process in response to unsubstantiated "market uncertainty."

4. The Commission should reject CalWEA's argument that the Commission lacks authority to allow PG&E to update the PPA prior to issuance of the 2014 RPS Solicitation.

CalWEA argues that PG&E's proposal to update its RPS Form PPA prior to solicitation issuance to reflect current market conditions and to minimize future contract disputes is inconsistent with the Commission's statutory obligation to review and approve the RPS plans.[54/] CalWEA's argument should be rejected, and PG&E's RPS Plan approved, because PG&E's proposal is consistent with the RPS statute and does not prevent the Commission from reviewing and approving each RPS PPA.

The RPS Statute sets forth certain enumerated elements that must be addressed in each RPS Plan.[55/] The only even indirect reference to a Form RPS PPA in these provisions is to the need for such plans to include a "bid solicitation."[56/] PG&E has met this statutory requirement by providing its Draft 2014 RPS Solicitation Protocol, including its Draft 2014 RPS Form PPA,

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53/ *Id.* at 11.

54/ CalWEA Opening Comments at 2-3.

55/ Cal. Pub. Util. Code § 399.13(a)(5).

56/ *Id.* at § 399.13(a)(5)(C).

as Appendix H to the June 4, 2014 filing. The RPS Statute also requires that the Commission "review and accept, modify, or reject" each RPS Plan prior to the initiation of an RPS Solicitation.[57/] The current RPS Plan proceeding clearly meets this requirement since the Commission will review and act on PG&E's Plan prior to issuance of the 2014 RPS Solicitation.

CalWEA's argument appears to be that the statute prohibits the Commission from allowing any changes to the Form RPS PPA after the Commission accepts, modifies, or rejects the respective RPS plans. Such an outcome is not required by statute, nor is it good public policy. The Form RPS PPA is simply a snapshot in time of how PG&E is intending to address risks and uncertainties in very rapidly evolving market conditions. While PG&E endeavors to anticipate certain changes in drafting its RPS Form PPA and generally expects the majority of the RPS Form PPA to remain unchanged between submission to the Commission and issuance of the Solicitation, PG&E should have the flexibility to make necessary updates to the RPS Form PPA to reflect current market realities prior to issuance of the RPS Solicitation. As a practical matter, having such flexibility saves all parties considerable time and effort, since bidders will then be basing their bids and redlines of the PPA on the most current thinking at PG&E. The alternative, which CalWEA advocates, would require that bids be based on a potentially outdated PPA, and each separate contract negotiation must then involve first updating the PPA. This alternative approach risks distorting the shortlisting process if shortlisted bidders cannot cost-effectively meet the updated PPA terms PG&E will require, or if non-shortlisted bidders could have offered more competitive bids if they had known about the updated terms. Thus, it is in all parties' interest that PG&E should provide the most current version of the RPS Form PPA, consistent with any required changes in the Commission's decision on the RPS Plans, at the issuance of the RPS Solicitation.

Furthermore, the Commission's ability to review and approve specific PPAs is not impacted by changes to the Form RPS PPA. PG&E will submit any executed RPS PPAs to the

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57/ *Id.* at § 399.13(c).

Commission for approval through the advice letter process, and PG&E is required to show as part of that filing all changes made to the RPS Form PPA in the final, executed agreement. The Commission and other parties who are non-market participants have the ability to review these changes, and the Commission can reject or requirement modifications to the final, executed PPA as a condition of approval.

5. The Commission should not require changes to contractual provisions related to the Western Renewable Energy Generation Information System ("WREGIS").

IEP raises concerns that WREGIS may not continue to play its current role of tracking the generation, trading, and retirement of Renewable Energy Credits ("RECs"), and on this basis makes several general recommendations for changes to the RPS Form PPA.[58/] Specifically, IEP suggests the RPS Form PPA be amended to refer to the REC accounting requirements established by the California Energy Commission ("CEC") rather than to the WREGIS requirements.[59/] IEP does not provide specific contractual language for Commission's consideration and parties' comments on this point.

The Commission should reject IEP's proposal because the current RPS Form PPA's language regarding WREGIS provides the level of specificity needed to ensure that PG&E gets all the RECs that it expects, and to ensure that there is no doubt about the Seller's obligation to take all necessary action to meet existing WREGIS reporting obligations. Although the role of WREGIS may change, this does not warrant major changes to the current contract provisions. In fact, the RPS Form PPA already accounts for the possibility of such changes in its definition of WREGIS: "WREGIS" means the Western Renewable Energy Generation Information System *or any successor renewable energy tracking program*."[60/]

58/ Opening Comments of IEP at 11.

59/ *Ibid.*

60/ June 4, 2014 Draft RPS Plan, Appendix H.1, Section 1.277 (emphasis added).

6. The Commission should reject IEP proposals to change SCE's PPA language regarding excess deliveries.

IEP opposes SCE's treatment of and compensation for deliveries in excess of the contract capacity (measured in megawatts) in any settlement interval (hour), or in excess of contract quantity (measured in megawatt-hours ("MWh")) over the calendar year.[61/] PG&E provides input on this issue since its RPS Form PPA has similar language.

First, IEP opposes SCE's provision that it will not pay for deliveries in excess of 100% of contract capacity, noting that in previous years SCE had paid for up to 110% of contract capacity.[62/] PG&E supports SCE's limitation as one way in which IOUs can ensure that Sellers do not intentionally overbuild their facilities with the expectation that they can deliver excess volumes for which the IOU has not planned. PG&E reminds the Commission that the 110% provision was never intended to allow developers with As-Available facilities to have an option to increase the contract capacity by 10%; but rather to acknowledge that under optimal weather conditions the facility might generate beyond the contract capacity from time to time for a limited basis. Under this scenario, the over delivery of energy beyond the contract capacity would largely be outside of the developers' control. PG&E now believes that certain developers may abuse this provision by intentionally overbuilding their facilities or providing a contract capacity that does not accurately reflect the generation capacity less auxiliary load, station use, or electrical losses under normal conditions, as required by PG&E's forms of RPS PPAs.

IEP suggests that these deliveries should be accepted because AB 327 implies a goal of maximizing RPS-eligible energy production.[63/] However, as discussed in Subsection III.A., above, AB 327 merely grants the Commission authority to raise RPS requirements. It does not require such increases or express or imply any policy with regard to requiring that IOUs accept volumes of deliveries from RPS resources under contract in excess of the contract capacity.

61/ IEP Opening Comments at 5-8.

62/ *Id.* at 6.

63/ *Ibid.*

The contract quantity is the parties' agreement as to the maximum capacity that a specific resource will put on the system at any given time. This is a well-established concept within the industry, and IEP's proposal therefore amounts to nothing more than a request that the Commission require IOUs to grant Sellers a free option to deliver potentially large incremental volumes. IEP suggests that any deliveries in excess of contract quantities would be "rare."[64/] However, if an IOU utility is required to accept and pay for deliveries exceeding contract capacity, IEP provides no support for its position that the Commission should expect such over-generation to be rare. If all RPS-eligible resources in the IOUs' portfolios were allowed to put 110% of their capacity on the system at any or all times, it would create significant uncertainty as to how much energy the utility may receive. Similarly, as noted by SCE, such excess deliveries could create a windfall for the Seller, and excess program costs for PG&E's customers, if the PPA is priced higher than alternative sources of RPS-eligible products in the current market.

IEP also suggests that Sellers should be guaranteed payment for energy in excess of 115% of annual contract quantity, even when market prices are negative.[65/] IEP argues that this is necessary because intermittent resources have uncertain output from year to year. However, PG&E submits that SCE's proposed provisions that accept and pay for up to 115% of the contract quantity adequately accommodate weather variation. The proposed PPA provisions strike a balance between the utility need to plan for a known amount of RPS energy, and the uncertainty in intermittent output. In combination with contract quantity, the Guaranteed Energy Production ("GEP") and excess energy provisions in PPAs are meant to embody the parties' agreement regarding the lower and upper bounds on contract volumes. Moreover, the Seller, which is the entity in the best position to estimate the likely output and capabilities of the resource, specifies the contract quantity and capacity that are included in the PPA. The minimum output requirement (GEP), allows for significantly less quantity to accommodate year-

64/ *Ibid.*

65/ *Id.* at 7-8.

to-year output variation, and PG&E's RPS Form PPA includes cure provisions when GEP is not met. The annual excess energy provisions address the upper bound. Requiring the utility to pay for deliveries in excess of 115% will incent the seller to underestimate annual deliveries, and create an opportunity for Seller windfalls and gaming in the procurement process.

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IV. CONCLUSION

For the foregoing reasons, the Commission should approve PG&E's Draft RPS Plan without modification and should adopt an interim RICA as part of the decision on the 2014 RPS Plans. The Commission should also issue a revised Scoping Memo in the LTPP docket specifically providing for the development of RICA calculation methodologies as part of Phase 1B of that proceeding.

Respectfully Submitted,

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Dated: July 30, 2014

VERIFICATION

I, Sandra Burns, 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 COMPANY'S (U 39 E) REPLY TO OPENING COMMENTS ON THE 2014 RPS PLANS AND RELATED PROPOSALS**, dated July 30, 2014.

The statements in the foregoing document 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 30th day of July 2014 at San Francisco, California.

/s/ Sandra Burns

Sandra Burns
Renewable Energy Principal
Pacific Gas and Electric Company