Rulemaking: 12-03-014
(U 39 E)
Exhibit No.: ______
Date: July 23, 2012
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2012 LONG-TERM PROCUREMENT PLAN

TRACK 1

REPLY TESTIMONY

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A. The Track 1 Issues Should Be Addressed This Year

Q 1 On page 4 of its Track 1 testimony, Calpine Corporation ("Calpine") argues that "the Commission should not authorize the IOUs to procure any new [emphasis in original] resources to meet local reliability needs until system reliability needs have also been determined." Does Pacific Gas and Electric Company ("PG&E") agree?

A 1 No. The need for resources due to local reliability considerations should be addressed this year, in Track 1, as has already been established in the May 17, 2012 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge ("Scoping Memo").

The Scoping Memo's determination to address local capacity needs in southern California this year, and to address the broader question of system reliability needs next year in a second track, makes sense for several rea First and foremost, based on the California Independent System Operator's ("CAISO") analysis, there is a pressing need for capacity to meet local requirements. Therefore, this question should be addressed now.

Other parties' disagreement with the CAISO's analysis, and differing opinions on the level of local capacity need in southern California, do no support deferring a decision on the matter. Since the CAISO, who has responsibility to operate the CAISO grid reliably, has concluded that there a substantial need, the California Public Utilities Commission ("CPUC" or "Commission") should address the matter immediately to reach its own judgment. The Commission should act now so that, if it agrees with the CAISO's conclusion that resources are needed, there will be enough time fo that need to be addressed.

Second, the basic analytic approach for evaluating local capacity need already established. The CAISO has used the same approach for evaluating local capacity needs, based on established reliability criteria, for sever years. The CAISO study here is longer term than the CAISO local capacity

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studies that have been used to determine year-ahead local capacity requirements for resource adequacy purposes, but the basic analytic framework is the same. Therefore, as the CAISO has completed and presented its analysis, it makes sense for the Commission to use that, as as the input other parties have provided in their testimony, to reach its independent determination of local capacity need.

There is more uncertainty associated with the CAISO's multi-year forward conclusions regarding local capacity needs here than there is with the CAISO's one-year forward conclusions presented in connection with year-ahead local capacity resource adequacy obligations. However, this is an unavoidable consequence of the fact that the further into the future one attempts to look, the more uncertainty there is. The higher level of uncertainty does not mean that the CAISO's multi-year study is flawed, but instead simply reflects the uncertainty inherent in long-term planning.

Third, evaluating system need in 2013 will be a challenging enough task. Local capacity needs should be addressed this year, instead of deferring t issue to 2013, in order to help limit the number of issues that must be addressed in Track 2.

Q 2 Do you agree with the Division of Ratepayer Advocates' ("DRA") suggestion that the Track 1 decision on local capacity need be deferred in order to t into account the final CPUC-adopted planning standards in Track 2 of the 2012 Long-Term Procurement Plan ("LTPP")?

A 2 No. DRA's suggestion[1] is troubling. Not only would this delay the Track 1 decision, but it would almost certainly cause delays in both the Track 2 a Track 3 decisions, as well. New information will always be available, but given the local need identified by the CAISO, the Commission should move forward now, using the information at hand, to evaluate the CAISO's analysis and conclusions.

B. The Costs of Capacity to Meet Local Capacity Requirements in Southern California Should Not Be Allocated to Customers in PG&E's Service Area

Q 3 In the direct testimony of Southern California Edison Company ("SCE"), on page 2, SCE states "[i]n the absence of multi-year forward procurement

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1 DRA Direct Testimony (Peter Spencer), p. 3.

mechanism that can secure generation capacity to meet the identified Local Capacity Requirements ("LCR") need and fairly allocate costs to all Load Serving Entities ("LSE"), SCE proposes that the Commission authorize SCE to procure new LCR generation needed in the LA Basin area on behalf of all system customers." Did SCE clarify this statement in discovery?

A 3 Yes. In response to PG&E Data Request PGE-SCE-001,[2] SCE stated that "all system customers" means "all customers served by SCE's electrical system and is limited to procurement of new generation capacity intended t meet CPUC-authorized LCR need in SCE's service territory."

Q 4 On page 2, SCE's testimony states that "[i]n the absence of a multi-year forward procurement mechanism that can secure generation capacity to meet the identified LCR need and fairly allocate costs to all LSEs, SCE proposes that the Commission authorize SCE to procure new LCR generation needed in the LA Basin area on behalf of all system customers." Also, on page 26 SCE states that that "LCR resources are required to meet system and local area reliability requirements. As such, the cost to SCE of procuring the LCR resources should be equally and fairly allocated to all LSEs and non-jurisdictional publicly-owned utilities ("POU") in the CAISO balancing area." Do you agree with these statements by SCE?

A 4 No. It appears that SCE's use of the term "system" is inconsistent and f confuses on whose behalf the LCR resources are being procured. Further, the absence of a multi-year forward procurement mechanism is irrelevant an does not justify having the Commission allocate to customers outside of SCE's service territory any of SCE's procurement costs for LCR resources needed for the LA Basin.

As noted in A3 above, SCE has acknowledged that "system customers" as discussed on page 2 of its testimony pertains to "all customers served SCE's electrical system.to meet CPUC-authorized LCR need in SCE's territory." Yet, on page 26 of its testimony, SCE's use of the term "syste appears to refer to the larger CAISO area.

2 SCE's response to Question 1a of PG&E Data Request No. PGE_SCE_001, is included in this testimony as Attachment 1.

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To the extent SCE means that costs of its procurement to meet the LCR need in the LA Basin are to be allocated to all benefiting customers in SC service territory—including bundled service, Direct Access ("DA"), and Community Choice Aggregation ("CCA") customers—but not to any customers outside of SCE's service territory, PG&E agrees with these statements by SCE. This is consistent with the direction of Public Utilities Code ("Pub. Util. Code") Section 365.1(c)(2)(A), which indicates that resources procured to meet "local area reliability needs for the benefit c customers in the electrical corporation's distribution service territory" should be allocated to the bundled customers of the utility procuring the resourc well as CCA and DA customers, but not to customers outside that electrical corporation's distribution service territory.

To the extent that SCE means that some portion of its costs for its procurement to meet the LCR need in the LA Basin (or elsewhere in the SCE service territory, such as Big Creek/Ventura) are to be allocated to any customers in PG&E's service territory, PG&E disagrees with these statements by SCE.

Q 5 Still referring to SCE's testimony on page 26, SCE states that "to the extent the LCR resources provide flexibility benefits (i.e., integration services intermittent resources) to the entire CAISO system, SCE is interested in seeking a broader cost allocation from all CPUC-jurisdictional customers benefitting from the increased flexible capacity." Should PG&E's custome be allocated a portion of the costs for SCE's procurement to meet LCR need in the LA Basin or elsewhere in the SCE service territory?

A 5 No. SCE appears to suggest that such costs may be allocated to PG&E's customers because incremental resources procured to meet the LCR need in the LA Basin may provide operational flexibility that helps the entire CA system integrate intermittent renewables and PG&E's customers benefit from such increased flexible capacity. PG&E disagrees with this premise. PG& contends that it is inappropriate to burden PG&E's customers with any portion of SCE's costs for procurement to meet the LCR needs in the LA Basin or elsewhere in SCE's service territory.

SCE has provided neither any analysis nor credible precedent to support having the Commission allocate to PG&E's customers a portion of SCE's costs to procure incremental capacity to meet the long-term LCR need in th LA Basin or elsewhere in SCE's service territory.

In contrast, the CAISO's testimony appears to support PG&E's view. The CAISO's testimony suggests that there is some threshold of flexibility needed for new capacity to satisfy the LCR need for the LA Basin, regardless of the amount of flexible capacity needed for the system to integrate intermittent renewables. The CAISO's testimony of Robert Sparks discusses the flexibility attributes that should be possessed by capacity procured to meet the LCR need in the LA Basin:

> The OTC generation characteristics include ramp rates and minimum output levels that allow the generation to be ramped-up quickly following the first transmission contingency in order to ensure reliable system operation following the next transmission contingency. The flexibility of the OTC generation allows efficient system dispatch when all transmission equipment is in-service, but still provides for reliable s operation following a transmission contingency. Replacement generation should have similar flexible characteristics. Quick starting generation would also provide for efficient system dispatch, but still provide for reliable system operation following a transmission contingency.[3]

Q 6 Does San Diego Gas & Electric Company ("SDG&E") propose a cost allocation rationale similar to SCE's, with costs associated with flexibility benefits of LCR procurement possibly allocated to customers throughout the CAISO system, including possibly PG&E customers?

A 6 No. SDG&E indicates that there may be interrelationships between the LC needs of the Western LA Basin sub-area, and particularly the Ellis sub-area and the LCR needs in the San Diego-Greater Imperial Valley-San Diego areas.[4] SDG&E's LCR needs are being considered in A.11-05-023. SDG&E has not suggested that the costs associated with the flexibility benefits of SDG&E's LCR procurement may be allocated to customers throughout the CAISO, including possibly PG&E customers.

Q 7 Does PG&E support allocating the net cost of LCR capacity to all benefitin customers as proposed by The Utility Reform Network ("TURN") and other parties in their Track 1 testimony?[5]

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3 Direct Testimony of the CAISO (Robert Sparks), May 23, 2012, p. 15.

4 Direct Testimony of SDG&E (John Jontry), June 24, 2012, p. 1.

5 TURN Direct Testimony, p. 24; SDG&E Direct Testimony, p. 9.

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A 7 Yes, as a general principle, PG&E agrees with TURN and others who recommend allocating the net cost of LCR resources to all benefiting customers. In the case of LCR resources procured pursuant to a Track 1 decision, PG&E recommends allocating the cost of these resources to all customers in the service area where LCR resources are added, whether bundled, DA, or CCA customers.

Q 8 Is there precedent for allocating LCR resource costs to all customers in service area where LCR resources are added?

A 8 Yes. Consistent with the guidance provided by Senate Bill ("SB") 695, which enacted Public Utilities Code Section 365.1(c), and with Decision ("D.") 11-05-005, the existing Cost Allocation Mechanism ("CAM") provides that the net capacity cost of resources which the Commission determines are needed to meet the local reliability needs of an electric distribution service territory should be allocated to the bundled, DA, and CCA customers in that electrical corporation's distribution service territor Section 365.1(c)(2)(A) provides:

> The net capacity costs of those generation resources are allocated on a fully non-bypassable basis consistent with departing load provisions as determined by the commission, to all of the following:
>
> i) Bundled service customers of the electrical corporation.
>
> ii) Customers that purchase electricity through a direct transaction with other providers.
>
> iii.) Customers of community choice aggregators.

Q 9 Do other parties reach the same conclusion as PG&E regarding CAM for allocating SCE's LCR resource costs?

A 9 Yes. Several parties reach the same conclusion as PG&E. For example, SDG&E states that "each investor-owned utility ("IOU") is responsible for procuring new generation resources to serve its distribution service territory, with the cost and benefits of the capacity associated with these new resou being shared by all "benefitting parties" located in that IOU's service territory."[6] TURN states that the net costs of such capacity should be allocated to all benefiting customers pursuant, to SB 695, SB 790 and other Commission policies.[7]

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6 SDG&E Direct Testimony, p. 9.

7 TURN Direct Testimony, p. 24.

Q 10 Do you have any comments regarding the issues identified by Commissioner Florio in his Assigned Commissioner's Ruling issued on July 13, 2012 in th proceeding?

A 10 Yes. The first topic identified by Commissioner Florio was if the Commission determines there is a local need in southern California, how SC and other LSEs in Southern California should be directed to meet that need "on behalf of the system." PG&E understands that this topic addresses procurement mechanisms for LCR resources in southern California and does not address cost allocation. However, to the extent that parties interpret topic as addressing cost allocation, for the reasons stated above, LCR resources are not associated with system need and thus the costs associated with resources should not be allocated to all customers in the CAISO. Instead, these costs should be allocated to the customers that benefit fro these resources (i.e., the bundled, DA and CCA customers located in southern California).

C. The Proposals to Modify the Cost Allocation Mechanism Should Be Rejected

Q 11 Could you summarize the proposals made by Alliance for Retail Energy Markets, Direct Access Customer Coalition, and the Marin Energy Authority ("DA/CCA Parties") in their joint testimony?

A 11 Yes, the DA/CCA Parties make proposals in three areas:

1) Process and criteria to determine when CAM is applicable;
2) Modifications to the CAM charge methodology; and
3) LSE Opt-Out from the CAM mechanism.

1. The Process and Criteria for Determining CAM Resources Should Not Be Changed

Q 12 Do you have any concerns with the DA/CCA Parties' first proposal regarding the process and criteria for the Commission determining when CAM procurement should occur?

A 12 Yes. First, the DA/CCA Parties' proposed process and criteria are biased and unfair to bundled customers. The DA/CCA Parties' version of cost causation unfairly assumes that CCA and DA customers have first rights to and can meet their requirements exclusively from existing resources. The DA/CCA Parties would require that bundled customers pay the marginal

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and presumably higher cost of any new resources as well as the cost of replacing existing resources.

Second, the DA/CCA Parties indicate that in determining when CAM procurement should occur, the Commission should determine "[i]f the load of the bundled utility customers is driving the peak or decreasing the system load factor..."[8] If the Commission were to adopt this cost causation proposal, then the Commission should require all DA and CCA providers to submit procurement plans, including detailed load and forecast data, in procurement proceedings that are used to determine CCA and DA load impacts on the need for new resources.

In the past, DA providers and CCAs have not submitted their own load data and forecasts in these proceedings. However, if the DA/CCA Parties' cost causation proposal is adopted, this would result in the Commission having an incomplete picture. If the DA/CCA Parties truly support their proposal, they should be willing to agree that all DA providers and CCAs be required to submit procurement plans to the Commission that include detailed load forecast information.

The DA/CCA parties recommend that their process be adopted in March 2013 when the IOU bundled procurement plans are currently scheduled to be filed.[9] If the Commission adopts this aspect of the DA/CCA Parties' proposal, it should require all ESPs and CCAs to file their own LTPP at that time, which would include load forecasts.

2. The Proposed Modifications to the CAM Charge Methodology Should Not Be Adopted

Q 13 Do you have any concerns with the DA/CCA Parties' proposals in Section V of their testimony regarding modifications to the CAM charge methodology?

A 13 Yes, PG&E has three areas of concern: (1) changes to the CAM calculation to include additional forecast revenue;[10] (2) levelization of the annual

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8 DA/CCA Parties Direct Testimony, p. 21, lines 14-15; see also p. 23, lines 14-18 (explaining that the Commission should evaluate IOU, Electric Service Provider ("ESP") and CCA loads).

9 DA/CCA Parties Direct Testimony, p. 34, lines 15-17.

10 DA/CCA Parties Direct Testimony, pp. 38-43.

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revenue requirement for utility-owned generation ("UOG") and front-loaded Power Purchase Agreement ("PPA") costs,[11] and (3) creating a cap for CAM costs.[12]

Q 14 How do the DA/CCA Parties propose to change the CAM calculation and what is your concern?

A 14 The DA/CCA Parties propose to change the proxy calculation that was part the Joint Parties' Proposal[13] to include additional incremental ancillary service revenue, renewable integration value and the options value of a long-term tolling agreement into the imputed revenues that offset the resource's cost in determining the CAM amount. The Joint Parties Proposal was part of the Settlement Agreement approved in Decision 07-09-044. The CPUC found that the Settlement was reasonable and that it balanced the interests of the various parties.[14] It is not reasonable to go back now to alter only certain aspects of that Settlement since it was a compromise on the various issues between all the parties.

Furthermore, the Joint Parties' Proposal's use of only non-spin imputed revenues in addition to imputed energy revenues was not an oversight. The inclusion of only non-spin imputed revenue was because it was incremental to imputed energy revenue that was calculated with perfect hindsight at the day-ahead energy price. Since the imputed energy revenue includes all the hours in which the resource is determined to have been economic to dispatch given actual day-ahead energy prices,[15] it would not be reasonable to impute any additional ancillary services revenues in those hours. In the hours when it is determined the resource would not have been economic to dispatch in the day-ahead energy market, imputed revenues for providing non-spinning reserves are included if economic and if the resource can provide such service.[16] The imputed day-ahead energy revenues are a

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11 DA/CCA Parties Direct Testimony, pp. 44-47.

12 DA/CCA Parties Direct Testimony, pp. 47-48.

13 The Joint Parties' Proposal was part of the settlement agreement in R.06-02-013 that was adopted in D.07-09-044 and is contained in Section IX of Appendix A of that decision.

14 Decision 07-09-044, p. 11 and Finding of Fact 6.

15 D.07-09-044, Appendix A, Section IX.B.2.a.

16 D.07-09-044, Appendix A, Section IX.B.2.b.

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proxy for all the energy or ancillary service revenue the resource could capture when it was economic to dispatch, and the imputed non-spin revenue is a proxy for all the incremental ancillary service revenue the resource capture when it was not economic to dispatch.

The DA/CCA Parties' proposal to include additional imputed revenues on top of those adopted in D.07-09-044 should be rejected because it is a one-sided change to an adopted settlement and would also double count imputed revenues in an attempt to lower the CAM charge.

Q 15 What is your concern with the DA/CCA Parties' levelization proposal?

A 15 The DA/CCA Parties' proposal to levelize the annual revenue requirement f UOG is inconsistent with the statutory language in Pub. Util. Code, Section 365.1(c)(2)(C), which requires the use of the annual revenue requirement for UOG that is subject to the CAM, not the levelized costs. Moreover, the DA/CCA customers should pay the same costs as bundled customers based on the normal trajectory of revenue requirements, which start higher and end lower than the levelized value. Using a levelized co creates an unfair advantage for DA and CCA customers. Moreover, in the Reopening Direct Access Proceeding (R.07-05-025), Mark Fulmer, one of the DA/CCA parties' witnesses, took the exact opposite position regarding using levelized costs. In that proceeding, Mr. Fulmer maintained that to determ an appropriate market price benchmark for renewable resource costs, the actual revenue requirement of UOG renewable resources should be used, instead of a levelized price.[17] In that proceeding, Mr. Fulmer's DA/CCA clients benefited from higher UOG revenue requirements in the first years operation and thus they opposed using levelized prices for UOG resources to determine the market price for renewable resources. Here, Mr. Fulmer's clients benefit from a levelized price and so he is taking the completely opposite position.

The DA/CCA Parties also propose that if a PPA contract is front-loaded then the actual annual costs of the PPA should not be used in calculating CAM charge, but rather that the costs used in the CAM should be levelized.

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17 See, R.07-05-025, Transcript from March 28, 2011 hearing at p. 22, line 23 to p. 23, line 25.

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Like the proposal to levelize the UOG revenue requirements, this proposal would shift costs to bundled customers from DA and CCA customers since the bundled customers would be paying for the full costs of the PPA in the early years of the PPA while the DA and CCA customers would be paying a CAM charge based on a lower annual cost. Interestingly, the DA/CCA Parties don't seem to advocate levelization if a CAM eligible resource had back-loaded costs.

Q 16 Is the DA/CCA Parties' proposal to create a cap on the CAM charge reasonable?

A 16 No, it is not. The DA/CCA Parties' testimony confuses cost and value. CAM stands for "Cost Allocation Mechanism." The DA/CCA Parties mistakenly claim that the CAM attempts to calculate the value of the Resource Adequacy ("RA") portion of the resource,[18] and that if the CAM is ever above some measure of RA value, the CAM charge should be capped at that level. This is confusing the residual cost represented by the CAM charge and RA value. The CAM charge is the residual cost of the resource after the energy and ancillary services revenues are netted from the total costs. This residual cost of a long-term contract will likely be higher than the short-term RA value of the resource. That does not imply that the total cost of the CPUC-approved CAM-eligible contract was unreasonable, but rather that the cost of new generation for system or local reliability is more expensive than short-term RA.

Furthermore, costs associated with CAM resources are not capped for bundled customers and thus the DA/CCA Parties' proposal would have the effect of favoring DA/CCA customers over bundled customers. The DA/CCA customers should be required to pay their fair share of any CAM-related costs.

3. Load-Serving Entities Should Not Have the Option to "Opt-Out" of the CAM Mechanism

Q 17 Do you have any concerns with the DA/CCA Parties' third proposal that DA and CCA providers be able to opt-out from the CAM?

18 DA/CCA Parties Direct Testimony, p. 47, lines 11-12.

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A 17 Yes. The DA/CCA proposal is not a necessary modification to implement the RA provision of SB 695, but rather a proposal that shifts costs from DA/CCA to bundled customers. If adopted, this opt-out may very well adversely impact reliability and impose additional administrative burden on IOUs and the Commission.

Q 18 Do you have any concerns with respect to DA/CCA Parties' suggested contract term for opt-out?

A 18 Yes. Under DA/CCA Parties' proposal, an LSE would only need to demonstrate a 5-year contract term to opt-out.[19] In resource need situations, or when there are no existing resources available with the right type of operating attributes for the LSE to meet its requirements, the LSE will need to commit to new resources. Most new generation resources require long-term contracts, 10 years or more in length. Thus, the DA/CCA Parties' proposal would not adequately protect system reliability.

Q 19 Do you have any concerns about the applicability of the DA/CCA Parties' proposal for LSE opt-out mechanism specifically relating to the Qualifying Facilities ("QF")/Combined Heat and Power ("CHP") Settlement adopted in D.10-12-035?

A 19 Yes. The DA/CCA Parties suggest that the opt-out mechanism should be applicable to all CAM procurement including CAM charges imposed pursuant to D.06-07-029, D.10-12-035, and any other Commission decision that imposes a non-bypassable charge for IOU procurement.[20]

Applying such an opt-out provision to procurement entered into under the QF/CHP Settlement ("Settlement") approved in D.10-12-035 may impact the IOUs' ongoing procurement of CHP resources.

The QF/CHP Settlement provided for one of two alternatives for allocating CHP procurement costs uniformly to all ESPs and CCAs.[21] Based on comments filed by DA/CCA representatives at that time, PG&E understood that some ESPs and CCAs may not want to procure CHP

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19 DA/CCA Parties Direct Testimony, p. 58, lines 20-23.

20 DA/CCA Parties' Direct Testimony, p. 58. PG&E interprets the DA/CCA Parties' citation at lines 19-20 of "D.11-12-035" to refer to D.10-12-035, the decision adopting the QF/CHP Settlement.

21 Settlement Term Sheet, Sections 13.1.2, 13.1.2.1 and 13.1.2.2

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resources, or may be unable to be competitive in doing so.[22] The Commission's decision to have the IOUs procure CHP on behalf of the DA/CCA customers impacted the CHP targets agreed to under the Settlement and the IOU's ongoing CHP procurement strategy.

Any change to the cost recovery structure for the CHP Program at this point would add substantial complexity and possibly alter the balance of benefits and burdens agreed to by the settling parties. Further, allowing opt-out would raise a number of questions not addressed in the DA/CCA Parties' testimony. First, if an LSE opts out of QF/CHP resources, is the IOUs' megawatt ("MW") target reduced accordingly? If yes, QF/CHP parties may express concerns. If no, bundled customers may see above market costs associated with QF/CHP procurement increase. Similar questions may be asked associated with QF/CHP procurement to meet greenhouse gas ("GHG") emissions reduction targets.

Q 20 Do you have any concerns with respect to DA/CCA Parties' proposal for the timing of LSE opt-out application?

A 20 Yes. According to DA/CCA Parties' current testimony, an LSE could submit the opt-out application any time after a Commission decision is approved, but before the IOU identifies a short list of potential winning bidders in Request for Offers ("RFO") process.[23]

This approach is problematic due to the uncertainty it would create during the initial phases of an IOU's planning for an RFO or other procurement approaches. Once an IOU receives Commission authorization to procure toward certain targets, it actively engages its internal and external resources to meet those targets. Any LSE opt-out could potentially change the IOU targets, necessitating a shift in the IOU's procurement strategy.

Q 21 Would there be additional administrative complexity to implement the Opt-Out mechanism?

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22 See e.g. Opening Comments of Shell Energy North America (US), L.P. on the Qualifying Facility and Combined Heat and Power Program Settlement Agreement filed October 25, 2010, at p. 7 (noting that ESPs and CCAs may not have the ability to procure CHP resources).

23 DA/CCA Parties' Direct Testimony, p. 56.

A 21 Yes, implementation of the DA/CCA Parties' Opt-Out proposal would add significant administrative complexity, both for the Commission and the IOUs. For example, the DA/CCA parties propose each non-IOU LSE would have the option to apply for an opt-out each time the Commission issues a decision approving the need for CAM procurement by an IOU, including procurement to meet obligations under the QF/CHP Settlement. Conceivably, for this procurement, some LSE's would opt out and some would not. Tracking the opt-outs, and the impact of each different opt-out on CAM charges on a resource-by-resource basis would be an administrative challenge for both the Commission and the IOUs.

The DA/CCA parties also suggest three different opt-out options, chosen at the election of the ESP or CCA. This optionality will allow each ESP or CCA to maximize their ability to opt-out and select the option that minimizes cost for their customers, further shifting costs to remaining bundled customers by increasing the residual quantity allocated back to bundled customers. Tracking which ESP or CCA elected each option, and verifying the necessary calculations to ensure that each ESP or CCA has met the conditions for each opt-out, for each eligible CAM procurement, would add significant administrative burden for the Commission.

Finally, if the Opt-Out applied to QF/CHP obligations, any ESP exercising an Opt-Out option would need to file a QF/CHP compliance report, similar to the IOU-filed reports. This imposes an additional administrative burden on the CPUC. Current CAM-related rate (the New System Generation Charge or "NSGC") varies by customer class. The Opt-Out proposal would make it necessary to create different NSGC rates by class for each ESP or CCA in an IOU's service territory based on which contracts each LSE exercised an Opt-Out option. This kind of contract by contract and ESP by ESP ratemaking would require significant additional resources to implement and for the Commission to track.

Q 22 Do you have any final observations regarding the DA/CCA Parties' CAM proposals?

A 22 Yes. In response to a PG&E data request, the DA/CCA Parties confirmed that their proposals are prospective only, that "the only effect on previously approved CAM projects would be on the calculation of the net capacity costs

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in future years.[24]" The DA/CCA Parties also confirmed that "[t]o the extent that agreements entered into under the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement approved in D.10-12-035 are subject to CAM cost recovery treatment, we would intend our proposal to apply prospectively to those contracts."[25]

For the reasons above, the DA/CCA Parties' proposed changes to the CAM mechanism should be rejected altogether. In any event, any adopted changes should not be applied retroactively. If an opt-out option is nonetheless considered, any DA/CCA resource used to support an opt-out must have the attributes specified by the Commission as needed to meet the identified LCR or system need. Resources without those attributes cannot be considered to fulfill these requirements, and no LSE should be allowed to opt-out based on access to resources without the needed attributes. Among many other things, this would require demonstration of a 10-year or longer resource commitment by the LSE opting out of CAM when it is opting out of new or repowered generation commitments made by the IOU (unless the resource it is being provided in place of has a shorter commitment period).

If an opt-out provision is to be considered, there must be a specific, limited window of time during which the opt-out provision would be available, for example, three months after the Commission authorizes CAM-eligible procurement. The timing window would start after the Commission's authorization to meet LCR or system need, and end after a fixed period of time.

PG&E does not believe that a CAM opt-out approach is workable, or that it would work in a manner that would be fair to bundled customers, or maintain reliability. Opt-out will substantially increase the administrative burden for IOUs and the Commission, may adversely impact reliability, and will impose additional burden to bundled customers. Opt-out should be rejected.

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24 DA/CCA Parties' response to Question 1 of PG&E Data Request No. PGE_Joint_001, is included in this testimony as Attachment 2.

25 DA/CCA Parties' response to Question 2 of PG&E Data Request No. PGE_Joint_001, is included in this testimony as Attachment 3.

D. The Commission Should Not Establish a Combined Heat and Power "Set-Aside" as a Part of This Proceeding

Q 23 The California Cogeneration Council ("CCC") states that "[i]f the state is serious about its CHP goals, the only way to achieve them is to maintain a place in the IOUs' portfolios for CHP, as determined in these LTPP proceedings. This includes assuming that CHP can meet both local and system capacity needs. Otherwise, the IOUs will eliminate the need for CHP by filling that need with conventional resources and then arguing there is no need for further CHP resources."[26] Do you agree with CCC's position?

A 23 No, PG&E does not agree with CCC's position that it is necessary to "maintain a place in the IOUs' portfolio for CHP" if, by this, CCC intends to establish an additional CHP set-aside procurement target above and beyond what was agreed to in the QF/CHP Settlement and approved by the Commission in D.10-12-035.

The CAISO's testimony presented in this proceeding, and discussed by CCC, provides estimates of the amount and type of capability needed in the system. If CHP resources can provide the desired attributes—and can do so in a cost-effective and environmentally sound manner when compared to other alternatives—then CHP will be selected to meet the resource need.

CHP is already brought into the IOU portfolio in several ways and does not need an additional set-aside. The existing programs that support CHP include the QF/CHP Settlement, Assembly Bill 1613, Public Utility Regulatory Policies Act ("PURPA") PPA for QFs less than 20 MW, and the Self-Generation Incentive Program. These programs offer CHP facilities of all sizes a preferred procurement process. The IOUs' obligation to purchase CHP under the CHP Program is clearly defined in the QF/CHP Settlement's Term Sheet. PG&E supports the QF/CHP Settlement and recommends that existing programs be given a chance to demonstrate success in achieving the state's policy goals prior to consideration of any additional CHP preference through the LTPP process.

Q 24 CCC states that CHP units can provide a measure of flexibility (p. 12), what is PG&E's view?

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26 CCC, Direct Testimony, p. 14.

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A 24 CCC observes that most CHP faces flexibility limitations due to thermal energy production requirements.[27] In order to meet the efficiency requirements in the QF/CHP Settlement, the California Energy Commission's ("CEC") efficiency standards for the CHP Feed-In Tariff ("FIT"), and the efficiency requirements of the Self-Generation Incentive Program ("SGIP"), CHP units operate to serve the thermal load. However, PG&E believes that a market is established for flexibility products, CHP may be able to suppl these products. Fair competition between flexible CHP and other resources supplying these products is desirable. Flexibility procurement should be technology neutral.

Local RFOs and related procurement should focus on the operating attributes needed to provide reliable and cost-effective service to the lo area. CHP should be allowed to participate in these local area procureme processes and evaluated based on their ability to support cost-effective l area reliability. PG&E cautions against planning to use CHP resources to meet a local area reliability need without a careful analysis of CHP's flexibility limitations.

E. The Commission Should Not Establish a Storage "Set-Aside" as a Part of This Proceeding

Q 25 What is your understanding of what the California Energy Storage Alliance ("CESA") recommends in its Track 1 testimony?

A 25 CESA makes three main recommendations. First, CESA recommends that "[t]he Commission's long-term procurement planning assumptions should begin including energy storage immediately," and "a very strong emphasis on energy storage in all planning scenarios."[28] Second, CESA proposes that "[t]he Commission should focus on assumptions needed to model the performance, costs, and benefits of energy storage."[29] And third, CESA recommends that the Commission adopt a multi-year procurement mechanism that includes energy storage. CESA explains that "the Commission should develop processes for multi-year procurement that

27 CCC Direct Testimony, p. 12.

28 CESA Direct Testimony, p. 7-9.

29 CESA Direct Testimony, p. 12-14.

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provide reasonable rates of return for energy storage investments, includin industry infrastructure and individual projects."[30]

Q 26 Could you explain PG&E's position on CESA's recommendations?

A 26 Yes. CESA's first and second recommendations are more focused on Track 2, the system need determination track of this proceeding. To the extent that CESA raises some or all of these topics in the future in Track PG&E may respond to them there.

With respect to Track 1, CESA has presented nothing to suggest that the CAISO's Track 1 analysis has erred in its treatment of storage. PG&E has objection to consideration of energy storage as one of the alternatives available to the meet the local capacity need identified in Track 1. Howe PG&E would oppose adoption of any preference or "set aside" for storage resources in Track 1.

CESA's third recommendation for a multi-year procurement process is outside the scope of Track 1. Multi-year procurement requirements are the subject of Track 3.[31] Also related to the issues raised by CESA, the Commission has indicated that it will "immediately begin the effort to finalize a framework for filling flexible capacity needs" in the ongoing resource adequacy rulemaking.[32]

PG&E supports the adoption of a multi-year procurement requirement for LSEs to meet their projected reliability and flexibility requirements. PG&E, however, does not support adoption of an energy storage procurement requirement, as CESA proposes. In general, set-asides increase costs for ratepayers and should be avoided. The actual selection of resources to meet a forward procurement requirement should be done through a competitive procurement process that enables all resources and all technologies, including storage, to compete on an equal footing to meet th resource identified need in Track 2.

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30 CESA Direct Testimony, p. 14-16.

31 May 17, 2012 Scoping Memo Assigned Commissioner Ruling of Assigned Commissioner Administrative Law Judge at p. 12.

32 D.12-06-025, p. 20.

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F. The CAISO's Treatment of Incremental Energy Efficiency, Demand Response, Combined Heat and Power, and Demand, Which Several Parties Criticized in Their Testimony, is Reasonable for Evaluating Local Capacity Needs

Q 27 In their testimony, several parties argue that the CAISO's Track 1 analysi fundamentally flawed.[33] Does PG&E agree with these parties' criticisms?

A 27 No. PG&E believes that determining local reliability needs requires a conservative approach, as was taken by the CAISO. Specifically, only thos resources (demand or supply-side) that have a high likelihood of being realized should be considered. For instance, it is very difficult to predict the geographic location of energy efficiency ("EE") savings from traditional programs that are open and available to everyone in the IOUs' service territories.

One modeling approach would be to allocate EE resources, adjusted for customer class, proportionately across the service territory. However, th forecast is fairly uncertain. It is very likely that some areas will over while others will underachieve, relative to the forecast.

Because of this, if one were to rely on such forecasts to evaluate loca capacity needs, then local reliability could be seriously compromised. This same rationale applies to non-CHP (other customer generation) which is also driven by customer choice. It is possible to encourage installations certain localities (for example the location adder in the CHP FIT), but th does not guarantee that the resources will appear. At some point it is too late to procure optimal resources at reasonable costs in order to compensate fo previous planning that assumed local resources that did not materialize. All resources that rely on customer behavior generally have a lead time to long to be effectively included in local planning. Using a conservative approach to determine local reliability needs is the more prudent approach take for planning and procurement.

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33 See, e.g. DRA Direct Testimony (Peter Spencer) p. 1; TURN Direct Testimony, p. 9.

Q 28 Some parties (including TURN) suggest that the CAISO's treatment of incremental EE, demand response ("DR"), and CHP is inappropriate.[34] What is PG&E's view?

A 28 PG&E's view is that these parties are being too optimistic in their appro evaluating local resource needs. They are suggesting that Demand-Side Management ("DSM") resources that are likely to be achieved on a system basis can also be achieved on a local planning basis. It is unlikely that will be the case across all areas, and the areas where it will not happen are unknown. There is significant variation with how DSM resources are adopted across an IOU's service territory. Including these savings withou significant reductions to account for potential shortfalls could put local reliability at increased risk.

It is too optimistic at this time to simply assume that 100 percent of incremental EE, DR and CHP can be counted on at the Local Capacity Area ("LCA") level.

PG&E suggests that if more optimistic assumptions are included, reductions should be made to account for the risks of the savings not materializing in the LCA.

Several parties[35] mention one or more of the following proposals: (1) the 12,000 MW renewable Distributed Generation goal; or (2) the 6,500 MW CHP goal from the Governor's Clean Energy Jobs Plan. None of these proposals have been fully described or defined, nor have they been evaluated for cost effectiveness compared to other options. All of them, at this point, are aspirations whose fulfillment will require future actior by utilities, private parties, and regulators, that may or may not actually occur. At this time these potential resources do not fully meet the stand "cost-effective, reliable, and feasible" in Pub. Util. Code, Section 454.5 It would be overly optimistic to assume these levels for these resources i Commission's evaluation of local capacity needs.

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34 TURN Direct Testimony at p 9.

35 See, e.g., DRA Direct Testimony (Peter Spencer) at pp. 8-10; California Cogeneration Council ("CCC") Testimony at p. 5; California Environmental Justice Alliance Comments at pp. 3, 23 and 26.

Q 29 The California Environmental Justice Alliance ("CEJA") suggests that the CAISO is inappropriately relying on a 1-in-10 demand scenario.[36] Does PG&E agree?

A 29 No. The CAISO's use of a 1-in-10 demand scenario to determine local capacity needs is a reasoned, conservative approach. CEJA does not elaborate as to why it believes this to be inappropriate. It is not. Load projections should be adequate to present a range of resource need that might occur. The CAISO's use of a 1-in-10 peak load scenario is consistent with this approach. The CAISO needs to ensure the system will be reliable under a variety of possible future states, most importantly a high load stress condition. In addition, the CAISO's use of a 1-in-10 forecast for local studies is appropriate because local regions may well experience a 1-in-10 peak lo

G. There Should Be No A Priori Presumption That Any Need Identified in This Track Will Be Met With Fossil-Fuel Powered Resources

Q 30 Both CEJA and DRA propose that the CAISO's modeling will lead to an over-procurement of fossil-fuel resources.[37] Does PG&E agree with these parties comments?

A 30 No. There should be no presumption that resource need will be met with fossil-fuel powered resources. Other resources should also be given the opportunity to meet any identified needs.

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[36] CEJA Direct Testimony (Bill Powers) at p. 32.

[37] CEJA Direct Testimony at p 30; DRA Direct Testimony at p. 2.

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PACIFIC GAS AND ELEC TRIC COMPANY

ATTACHMENT 1

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET PGE-SCE-001

To: PG&E
Prepared by: Colin E. Cushnie
Title: Director, Energy Planning
Dated: 06/27/2012

Question 01.a:

Q 1: At p. 2, SCE's testimony says that "[i]n the absence of a multi-year forward procurement mechanism that can secure generation capacity to meet the identified LCR need and fairly allocate costs to all LSEs, SCE proposes that the Commission authorize SCE to procure new LCR generation needed in the LA Basin area on behalf of all system customers." Regarding this statement,

a. Please explain what SCE means by "all system customers." In particular, please identify (1) which customers, (ii) in which service areas outside of SCE's service area, and (iii) whether within or outside of the CAISO.

Response to Question 01.a:

The subject statement's reference to "all system customers" pertains to all customers served by SCE's electrical system, and is limited to procurement of new generation capacity intended to meet CPUC-authorized LCR need in SCE's service territory. SCE is not proposing to allocate contract costs associated with procurement to meet LCR needs in SCE's service territory to customers outside of SCE's service territory.

PACIFIC GAS AND ELEC TRIC COMPANY

ATTACHMENT 2

Recipient:	Alliance for Retail Energy Markets (AReM), Direct Access Customer Coalition (DACC) and Marin Energy Authority (MEA)
PG&E Data Request No.:	PGE_JOINT_001
PG&E File Name:	LongTermProcure2012-OIR_DR_ PGE_Joint001-Q01-Q07
Request Date:	July 3, 2012
Due Date:	July 18 , 2012

Q 1: Do your proposals regarding the Cost Allocation Methodology ("CAM") in the Track 1 testimony of Sue Mara and Mark Fulmer have any impact or effect on PG&E's recovery and/or allocation of costs associated with the Marsh Landing Power Purchase Agreement ("PPA") approved in D.10-07-045?

Witnesses: Ms. Mara and Mr. Fulmer

RESPONSE: We intend our proposal to apply prospectively. The only effect on previously-approved CAM projects would be on the calculation of the net capacity costs in future years. The proposal would not impact PG&E's overall cost recovery for Marsh Landing, only the CAM amounts.

a. If your response is anything other than an unequivocal "No", describe in detail how your proposals would or could impact or effect the recovery and/or allocation of costs associated with the Marsh Landing PPA.

RESPONSE: See answer to Question 1.

b. Are you proposing any change or modification to the calculation of net capacity costs included in the III.D of the Partial Settlement Agreement approved in D.10-07-045 for the Marsh Landing PPA? If your response is anything other than an unequivocal "No", describe in detail the proposed change(s) or modification(s).

RESPONSE: Yes. Mr. Fulmer recommends improvements to the calculation of net capacity costs on pages 34-50 of his testimony.

c. Are you proposing that Load-Serving Entities ("LSEs") be able to opt-out of the cost recovery and/or allocation of net capacity costs included in the Partial Settlement Agreement approved in D.10-07-045 for the Marsh Landing PPA? If your response is anything other than an unequivocal "No", describe in detail your proposal as to when and under what conditions LSEs could opt-out.

RESPONSE: No. The proposal is prospective, as discussed on pages 54-55 of Ms. Mara's testimony.

PACIFIC GAS AND ELEC TRIC COMPANY

ATTACHMENT 3

Recipient:	Alliance for Retail Energy Markets (AReM), Direct Access Customer Coalition (DACC) and Marin Energy Authority (MEA)
PG&E Data Request No.:	PGE_JOINT_001
PG&E File Name:	LongTermProcure2012-OIR_DR_ PGE_Joint001-Q01-Q07
Request Date:	July 3, 2012
Due Date:	July 18 , 2012

Q 2: Do your proposals regarding the CAM in the Track 1 testimony of Sue Mara and Mark Fulmer have any impact or effect on PG&E's recovery and/or allocation of costs associated with agreements entered into under the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement approved in D.10-12-035?

Witnesses: Ms. Mara and Mr. Fulmer

RESPONSE: To the extent that agreements entered into under the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement approved in D.10-12-035 are subject to CAM cost recovery treatment, we would intend our proposal to apply prospectively to those contracts. The only effect on previously-approved CAM projects would be on the calculation of the net capacity costs in future years. The proposal would not impact PG&E's overall cost recovery of QF/CHP contracts, only the CAM amounts.

a. If your response is anything other than an unequivocal "No", describe in detail how your proposals would or could impact or effect the recovery and/or allocation of costs associated with agreements entered into under the QF/CHP Settlement.

RESPONSE: See answer to Question 2.

b. Are you proposing any change or modification to the calculation of net capacity costs included in Section 13.1.2.2 of the Term Sheet that was included in the QF/CHP Settlement? If your response is anything other than an unequivocal "No", describe in detail the proposed change(s) or modification(s).

RESPONSE: No. That section of the Term Sheet contains no details on how the net capacity costs would be calculated. Pages 34 through 50 of Mr. Fulmer's testimony recommends specific changes to the calculation of net capacity costs that would apply to CAM allocations for QF/CHP contracts going forward.

c. Are you proposing that Load-Serving Entities ("LSEs") be able to opt-out of the cost recovery and/or allocation of net capacity costs included in Section 13 of the Term Sheet that was included in the QF/CHP Settlement? If your response is anything other than an unequivocal "No", describe in detail your proposal as to when and under what conditions LSEs could opt-out.

Witness: Ms. Mara

RESPONSE: Yes. An LSE would be permitted to opt-out of the cost recovery and/or allocation of net capacity costs included in the QF/CHP Settlement

provided the ESP or CCA requested the opt-out in accordance with the timing specified on page 56 of Ms. Mara's testimony. The precise requirements applicable to such an opt-out would be determined by the Commission.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIF ICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF
JANICE FRAZIER-HAMPTON

Q 1 Please state your name and business address.

A 1 My name is Janice Frazier-Hampton, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company ("PG&E").

A 2 I am director of Integrated Resource Planning within the Energy Policy, Planning and Analysis Department of PG&E's Energy Procurement organization. My department is responsible for long-term planning for energy procurement.

Q 3 Please summarize your educational and professional background.

A 3 I have a bachelor of business administration degree in finance from Northeast Louisiana University, Monroe, LA, and a master of business administration degree with a concentration in finance from Golden Gate University, San Francisco.

I joined PG&E in 1982 and have held various positions of increasing responsibility in the Finance, Regulatory Relations and Energy Procurement organizations. I was promoted to director in 2001. I assumed my current position in March 2010.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Questions/Answers 1-12 and 23-30 of PG&E's Reply Testimony.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RICK MARTYN

Q 1 Please state your name and business address.

A 1 My name is Rick Martyn, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company ("PG&E").

A 2 I am a principal in Long Term Energy Policy within the Energy Policy, Planning and Analysis Department of PG&E's Energy Procurement organization.

Q 3 Please summarize your educational and professional background.

A 3 I have a bachelor of arts degree in economics from the University of California at Santa Cruz.

I joined PG&E in 1992 and have held positions of increasing responsibility in the Regulatory and Energy Procurement organizations. I assumed my current position in August 2011.

Q 4 What is the purpose of your testimony?

A 4 I am co-sponsoring Questions/Answers 13-22 of PG&E's Reply Testimony.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RAY D. WILLIAMS

Q 1 Please state your name and business address.

A 1 My name is Ray D. Williams, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company ("PG&E").

A 2 I am a director within the Energy Policy, Planning and Analysis Department of PG&E's Energy Procurement organization. I oversee the team responsible for a number of long term energy policy planning matters.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from Clark University in 1975 with a bachelor of arts degree in geography and from Stanford University in 1981 with a master of science degree in civil engineering. From 1975 to 1979, I was employed by the Massachusetts Executive Office of Environmental Affairs.

I began work with PG&E in 1981. In June 2004, I became a director supporting regulatory activities and policy development related to long-term energy policy and procurement, including PG&E's policies regarding greenhouse gas policy development and implementation.

Q 4 What is the purpose of your testimony?

A 4 I am co-sponsoring Questions/Answers 13-22 of PG&E's Reply Testimony.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

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