BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	R.12-03-014 (Filed March 22, 2012)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) COMMENTS ON TRACK III RULES ISSUES

CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-6971
Facsimile: (415) 973-0516
E-Mail: crmd@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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Pursuant to the *Administrative Law Judge's Ruling Seeking Comment on Track III Rules Issues* ("ALJ Ruling"), issued March 21, 2013 by Administrative Law Judge ("ALJ") Gamson, Pacific Gas and Electric Company ("PG&E") respectfully submits the following comments addressing each of the issues identified in the ALJ Ruling. PG&E's comments are organized to track the seven specific issues identified and questions raised in the ALJ Ruling.

1. **Maximum and Minimum Limits on IOU Forward Purchasing Of Energy Capacity, Fuel and Hedges**

   a. **Should the Commission modify the Assembly Bill (AB) 57 bundled procurement guidelines to indicate minimum and maximum limits for which the three IOUs must procure for future years? If so, should these minimum and maximum limits address energy, system resource adequacy (RA), local RA, and/or flexibility?**

PG&E's current Commission-approved Bundled Procurement Plan ("BPP") includes limits on PG&E's authority to procure physical products and financial hedges. PG&E does not oppose continuing to include these limits in future BPPs and does not oppose changing these limits to, or supplementing them with, new limits as discussed below.

With regard to supplementing the current limits in PG&E's BPP, PG&E would support procurement limits on electricity, natural gas purchases for its electric portfolio, Resource

Adequacy ("RA"), and greenhouse gas ("GHG") compliance instruments, including position and execution limits.[1/]

This is similar to the approach taken by Southern California Edison Company ("SCE") in its bundled procurement plan. These procurement limits would only apply to PG&E's physical commodity purchases at a fixed price and financial hedges. Commodity purchases at physical index prices should not be subject to these limits because the commodity is purchased for physical reliability or other procurement obligations and does not change the financial position of the portfolio.

Maximum position limits would be defined as follows:

- Position limits are set at the forecast expected commodity requirement calculated using prices at a two standard deviation high level. For example, the forecast expected natural gas requirement would equal the natural gas for economic dispatch of PG&E-owned and PG&E-tolled generating units calculated at a two standard deviation high market heat rate plus the forecast equivalent short natural gas position from PG&E-contracted Qualifying Facilities ("QFs") and the natural gas equivalent of PG&E's forecast net short electric energy position; and,
- The position measured against the position limits includes all fixed price commodity and commodity hedge positions (buys net of sales) and excludes commodity basis positions (to avoid double counting).

Maximum execution limits would be defined as follows:

- Execution limits are set on a calendar-year basis and are applied to the "Remaining Position," which is defined as the net of the maximum commodity position limits and current fixed-price commodity and commodity hedge positions.
- Execution limits are the summation of 100 percent of the current (remaining) calendar year Remaining Position, 50 percent of the following calendar year (Year 2) Remaining Position, 33 percent of the Year 3 Remaining Position, 25 percent of the Year 4 Remaining Position, etc.

Any such limits would be included in PG&E's BPP and could be updated by advice letter if warranted by changes in PG&E's portfolio or market conditions. PG&E's limits would be

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1/ Limits may be monthly or annual depending on the commodity. Limits on flexibility are premature as this is the subject of the current RA proceeding (Rulemaking ("R.") 11-10-023).

confidential to prevent PG&E's trading counterparties from using this information to extract higher prices from PG&E.

Minimum limits for positions and executions should be set only to the extent the Commission desires a minimum level of hedging to manage bundled customer risk.

Limits for the purchase of distillate fuel for use at Humboldt Bay Generating Station would reflect the air quality permits for the power plant.

Regarding limits for RA, it is premature to consider minimum and maximum limits for flexible capacity.

The Commission has not yet adopted RA requirements for flexible capacity. Minimum and maximum limits for investor-owned utilities ("IOUs") to procure flexible capacity should not be established until RA requirements for flexible capacity are adopted.

As PG&E has advocated in its September 20, 2012 motion in this proceeding and in its concurrent motion in R.11-10-023, the resource adequacy proceeding,[2/] multi-year forward procurement requirements for RA – including flexibility as well as system RA – are slated to be considered in Track 3 of this proceeding but instead, should be consolidated into the scope of the RA proceeding where efforts are already underway to address resource flexibility needs.

As PG&E noted in its concurrent motions, there is a growing consensus that one-year forward RA procurement requirement applicable to all load serving entities ("LSEs") should be extended to a multi-year timeframe. Given that multi-year RA requirements should apply to all LSEs, not just IOUs, resolution of the multi-year forward procurement requirements would be best addressed in the RA proceeding, which applies to all LSEs. Considering these closely related topics together in one forum will ensure consistent policy considerations are applied to the multi-faceted issues currently being considered. In addition, considering these issues together will make the most efficient use of limited resources for both the Commission and for

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2/ *See*, September 20, 2012, concurrent motions filed in R.12-03-014 and R.11-10-023, Motion of PG&E to Move the Track 3 Multi-Year Procurement Requirement to the Resource Adequacy Proceeding, and to Defer Remaining Track 3 Issues interested parties.

Minimum limits to procure system RA for "future years" to meet the one-year-ahead system RA requirement should not be imposed in the BPP at this time. As currently specified in PG&E's BPP, forward procurement of system RA by PG&E already occurs in quantities that makes any minimum limit either a superfluous constraint that would not change procurement, or a binding constraint that would unnecessarily and unfairly commit the IOUs' bundled customers to *de facto* multi-year forward requirements that are not imposed on non-IOU LSEs.

In sum, PG&E would propose minimum and maximum position limits for the items described above[3/] when it submits its preferred analysis in Track 3, reflecting changes to the base assumptions and scenarios approved in Decision ("D.") 12-12-010, which adopted the Track 2 base planning assumptions and scenarios.[4/] PG&E's preferred analysis would be applicable for the first five years of the BPP, similar to the authority that was granted in the 2010 long-term procurement plan ("LTPP") proceeding, R.10-05-006.[5/]

b. How may the Commission best balance issues regarding departing load in any future requirements for procurement?

PG&E's response addresses how departing load issues can be best incorporated into maximum and minimum limits in forward purchasing. In the LTPP process, the IOUs utilize departing load forecasts that reflect departures of both Community Choice Aggregation ("CCA") and Direct Access ("DA") customers.[6/] Each IOU's BPP, including the maximum and minimum

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3/ Procurement limits discussed above include physical commodity purchases at a fixed price and financial hedges for electricity, natural gas purchases for its electric portfolio, RA, and GHG compliance instruments, including position and execution limits.

4/ D.12-12-010, Ordering Paragraph ("OP") 3: "Southern California Edison Company, San Diego Gas & Electric Company and Pacific Gas and Electric Company (collectively, the utilities) shall use the base scenario and assumptions in Attachment A for purposes of their bundled plan forecasts in this proceeding. The utilities may also provide additional information examining the impact of using other assumptions and scenarios."

5/ *See* D. 12-01-033 at p. 16, "SCE's proposal, which SCE refers to as its "preferred analysis," requests variations form standardized planning assumptions. . . . SCE is authorized to use its preferred analysis methodology, but only up to five years from the date of this decision, and with certain exceptions as described below. Beyond that date, SCE must use the standardized planning assumptions, except as otherwise noted . . . ."

6/ D.12-01-033 at pp. 30-31.

procurement limits, incorporate these departing load forecasts. Thus, there is no need for additional Commission action on this issue as it has already been addressed in previous LTPP proceedings.

2. Impacts of Transparency on Forward Procurement

Both of the questions raised deal with the issue of confidentiality and as such, are outside of the scope of this LTPP Track 3 proceeding. To the extent that the Commission believes these specific confidentiality questions, premised as questions related to transparency, need to be addressed, they should be addressed in the Commission's confidentiality proceeding where these and other confidentiality issues can be considered more comprehensively.

a. Should the Commission require the three major electric IOUs to provide more public transparency into the levels of future procurement for which each has entered into a contract? What confidentiality rules could be changed or removed? In particular how can the IOUs provide visibility to the California Independent System Operator (CAISO) regarding their midterm procurement contracts?

This subpart raises several questions. The first two questions address whether the IOUs should identify, more publicly, the level of future procurement for which they are contracting and how confidentiality rules associated with future procurement can be changed or removed.[7/] In other words, should the IOUs be required to publicly disclose their respective net short positions?

The current level of transparency should not be changed. It strikes the right balance between bundled customer's interests and the interests of market participants that want to meaningfully participate in proceedings that impact constituents and organizations they represent.

Under Public Utilities Code section 454.5(g),[8/] the Commission is required to adopt

7/ PG&E is interpreting the first two questions as going together. The first question asks if there should be more transparency about forward procurement and the second appears to ask, if there should be more transparency, then how should the rules be changed or removed to accomplish this goal.

8/ Section references are to the Public Utilities Code unless otherwise noted.

appropriate procedures to ensure the confidentiality of market sensitive information. In D.06-06-066, the Commission defined "market-sensitive information" as information "with the potential to affect the market for electricity in some way."[9/] In that decision, the Commission applied this definition to a number of different types of information to determine whether it was market-sensitive. With regard to forecasts of an IOU's net short, as well as near term forecasts of energy and capacity needs, the Commission determined that this information is market sensitive and should therefore be treated as confidential under Section 454.5(g).[10/]

Nothing has changed since D.06-06-066 was issued that should cause the Commission to change this determination. If market participants are aware of the IOUs' respective net open positions, they can readily use this information in a way that would affect energy markets and market prices. For example, if a generator knows that an IOU is short electricity in a certain time period and that there is a shortage of available supply, then the generator can increase its asking price for energy and capacity, which would be detrimental for customers.

Moreover, a generator that controlled several facilities and was aware of an IOU's open position could decide not to offer certain facilities to the IOU to limit the available supply and ask for extremely high market prices for its other generating units. Because market participants could use the IOUs' respective net short information to affect market prices, this information should not be made publicly available.

The third question in this subpart concerns the sharing of procurement information with the CAISO. The CAISO is not a market participant and PG&E has typically been able to share certain market sensitive information with the CAISO under the terms of a Non-Disclosure Agreement ("NDA"). To the extent the CAISO needs information from the IOUs regarding mid-term procurement contracts, that information can be made available to the CAISO in a confidential manner under an NDA.

9/ D.06-06-066 at p. 42.
10/ *Id*. at p. 63 (describing approach to different types of IOU data).

Finally, PG&E notes that the CAISO is not the only party that receives forward contracting information from the IOUs. Each of the IOUs has a Procurement Review Group ("PRG") that is made up of various non-market participants, including the Commission's Energy Division ("Energy Division"), the Division of Ratepayer Advocates ("DRA"), The Utility Reform Network ("TURN"), and other non-market participants. The IOUs are required to review with the PRG transactions that are three months or longer in duration[11/] and to provide quarterly reports to the PRG on their current open position for two years forward.[12/] PRG members can also request specific information regarding an IOU's net open position and forward procurement needs or plans.

This illustrates that there is already a significant amount of transparency regarding the IOUs' forward procurement *with non-market participants*. However, it is important that this information not be made publicly available to market participants who could use the information to affect market prices and ultimately increase customer costs.

b. How can bids and offers into request for offers (RFOs) be released publicly? What other information can be released?

Disclosure of RFO bidding and pricing information should not be required because it is not generally in the best interest of customers. After an RFO has been completed, if Commission approval of the RFO results is required, the IOUs will typically provide a significant amount of public information regarding the results of the RFO. For example, in Application ("A.") 09-09-021 for approval of the winning offers from PG&E's 2008 Long-Term Request for Offers ("LTRFO"), PG&E provided testimony which described the number of offers and offer variations received, offers that were rejected or non-conforming, the evaluation process used to review the offers, the shortlisting process, and the winning offers.[13/]

11/ D.07-12-052, Appendix E at 1.
12/ D.12-01-033 at p. 15.
13/ *See* A.09-09-021, PG&E's Prepared Testimony, served September 30, 2009 at pp. 3-1 to 3-29.

Although there were some redactions in this testimony for market sensitive information, most of the testimony was public. In confidential appendices, PG&E and the Independent Evaluator ("IE") also provided lists of all of the offers received in the 2008 LTRFO, descriptions of the offers, evaluations of the offers, and the offers' market valuations.[14/] Similarly, in its advice letter submitting the results of the second Renewable Auction Mechanism RFO, PG&E included, in the public portion, a description of the number of offers and offer variations received, the types of various offers (*e.g.*, baseload, peaking, etc.), and the evaluation process.[15/] In short, the IOUs already make a substantial amount of information publicly available regarding the RFO process and results. Non-market participants, such as PRG members, can also receive more detailed, market sensitive information simply by signing an NDA in a proceeding.

Information about winning bids is generally made available through the application or advice letter process, with the exception of market-sensitive information associated with a winning bid, such as pricing or contract terms. The information that is generally not made publicly available concerns information regarding non-winning offers. It is likely that non-winning bidders would not want information concerning their offer publicly disclosed so that competitors could use that information to tailor their bids in the future. It is PG&E's experience that bidders in RFOs expect their bid information to remain confidential, that they would not want this information publicly disclosed as it would disadvantage them in future solicitations.

This is exactly the type of situation contemplated by General Order 66-C, Section 2.8, in which an IOU receives information "in confidence from other than a business regulated by this Commission where the disclosure would be against public interest." If the IOUs were required to disclose non-winning bid information, potential bidders may decide not to participate in an RFO, which would not be beneficial to the public as it would limit RFO competition and potentially raise prices. Alternatively, bidders may modify their bids or provide less information

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14/ *Id.*, Confidential Appendices 1.1 and 5.1 Appendix B.

15/ Advice Letter 4114-E, filed September 28, 2012, at pp. 3-5.

if they believe that information from non-winning bids will be made public. This result would also not be in the public interest. The current amount of disclosure regarding RFO offers strikes the appropriate balance. No additional rules need to be adopted.

3. Long-term contract solicitation rules

a. Should the Commission adopt a rule that explicitly indicates that existing power plants may bid upgrades or repowers into new-generation RFOs?

RFOs for new generation, typically referred to as Long-Term RFOs or LTRFOs, are generally designed to meet an incremental need for new system, local or flexible capacity. In the past, LTRFOs have been limited to new or repowered resources that are capable of addressing the incremental need. This limitation should remain in place. Existing facilities, including upgrades to existing facilities, should continue to be considered in short-term or intermediate-term solicitations. However, allowing existing resources to compete in new-generation LTRFOs may lead to over-procurement, increased costs for customers, higher emissions, and/or a failure to meet the needs of the RFO.

A repowered facility is fundamentally different from an existing resource that has been retrofitted or upgraded. A repowered facility is, in essence, a new facility on a site where a different facility had previously been located. A repowered facility is a generation facility where substantial replacement of old equipment has occurred, such that the facility's performance and economic life are similar to that of a new facility of like technology.

For example, if an owner demolished a unit at the site of an existing resource and built a new unit in the same location, that new unit would be a repowered facility. By contrast, if an owner made improvements to an existing resource that improved the efficiency of the facility, but did not involve replacement of all of the combustion or steam turbines, these improvements would not qualify the facility as repowered.

Existing facilities, including upgrades to existing facilities, do not provide the same benefits as a new or repowered resource. In most cases, upgrades will not extend the useful economic life of a facility to match what is offered by a new or repowered resource.

Furthermore, upgrades are unlikely to match the efficiency or reduced emissions offered by a new or repowered resource.

Allowing existing resources to compete in LTRFOs increases the potential for over-procurement (and higher costs) for customers. In most cases, it is impractical to separate a contractual agreement for incremental, retrofitted capacity from the rest of the existing plant. The likely result would be a contract structured for the entire facility, not just the incremental capacity associated with the upgrade. This may result in over-procurement of overall capacity just to meet the mandate to contract for the new, incremental capacity. In addition, the existing gas-fired generators tend to prefer a bundled, tolling structure. If a tolling structure is used for a transaction with an upgraded facility, it will likely result in over-procurement of energy for the utility portfolio as well as capacity.

Also, allowing existing resources to compete against new or repowered facilities might provide suboptimal incentives to the existing resources, which could result in higher costs. If allowed to compete against new facilities, the owners of existing resources may provide less cost-competitive offers than they would if they were only competing against other existing resources. If existing resources know their offers are being compared against offers from new resources, their incentive is to provide offers just below price of a new resource. This would result in a negative outcome for customers, as the owners of existing resources would have the opportunity to extract higher above-market costs from customers.

A final concern with allowing existing resources to compete in LTRFOs is that allowing older, existing units to compete against new resources may support less efficient and higher GHG-emitting resources. A better outcome may be for these sites to be repowered rather than continue to operate as is.

i. How should the existing and upgraded components of the repowers be valued differently in an RFO? How can additions such as energy storage be added to existing facilities and be valued against other types of offers?

As noted above, repowers that extend the useful life of a facility to match that of a new resource should remain eligible to compete in LTRFOs for new generation. Existing facilities, including upgrades to existing facilities, should only be allowed to compete in short-term or intermediate-term RFOs. This separation will allow utilities to meet the RFO needs in a cost-effective manner for customers without the risk of over-procurement. The same principle should apply to energy storage that is incorporated into repowers and upgrades of existing facilities. If the storage technology results in a facility with a remaining useful life equivalent to a new resource, it should be eligible to compete through an LTRFO.

In earlier LTPP proceedings, some parties have proposed to have set-asides or preferences for preferred resources, including energy storage. These proposals should be rejected. Carve-outs and set-asides have a strong potential to increase costs. PG&E recommends the Commission continue to apply a least-cost best-fit ("LCBF") approach, allowing eligible resources compete on equal footing. The Commission should not allow itself to be placed in the position of supporting any specific technology *a priori*.

The extent to which storage technology or other upgrades may be able to improve the incremental efficiency and output of California's existing fleet of generating facilities is uncertain. While equipment could be installed to improve the efficiency of existing facilities, incremental capacity from those facilities is limited by several factors. Facilities have a variety of constraints including transmission and generator size that limit maximum output. Furthermore, many existing gas-fired facilities in California (both combined cycles and peakers) already have inlet cooling equipment installed to improve efficiency and output on hot days. Installing additional equipment at an existing facility would require the facility to be offline for a period of time (meaning lost revenue and lack of availability for reliability purposes), and may trigger additional permitting or zoning review.

Once the parameters of a solicitation are established, PG&E's offer evaluation methodologies are capable of comparing all eligible offers, including those that have a storage component, with each other.

ii. Should contracts for repowering or upgrading of facilities be restricted to the same length of contracts as new facilities? If not, please explain why there would be different contract lengths or different terms, and how these differences would be reflected in the valuation of bids.

PG&E's LTRFOs are targeted to address a need for new capacity. Transactions resulting from these LTRFOs have a contract duration that provides sufficient economic incentives for the sellers to recover investment in order to construct new or repowered resources. The investment and risk criteria for a retrofit or upgrade to an existing resource are substantially less than for a new or repowered resource. Thus, contracts for existing facilities, including facilities that have incremental upgrades, can be shorter in duration than a contract for a new or repowered resource.

PG&E takes a portfolio approach to energy procurement. Portfolio need changes over time. To reduce risk, the portfolio includes a range of tenors across products which are procured ratably over time. This strategy provides PG&E the flexibility to manage its short-term, intermediate-term and long-term needs thereby providing flexibility to match customer needs and resources in a cost effective manner. If PG&E were required to enter into more long-term agreements, it would lose some flexibility in managing its portfolio.

iii. Is there any information (additional or subtracted) from the RFO or application templates that would need to be changed? Would Energy Division review the RFO differently?

Protocols may need to be changed for future RFOs, and to some degree, application templates. The portions of the protocols that may need to be amended include eligibility requirements and contract options, both of which are dependent on the identified procurement needs for a future solicitation, especially taking into consideration whether the need is longer-term versus short- or intermediate-term. Also, future solicitations should be specific regarding the operational characteristics that a *portfolio* of procured resources is required to have.

Winning offers in an RFO should possess the operating attributes and minimum eligibility criteria required to satisfy the need. Otherwise, the resource will not contribute to satisfying the identified needs. Minimum eligibility requirements help to quickly identify offers that are not effective in meeting the specified need. In addition, minimum criteria may serve to discourage ineffective offers, streamlining the RFO process without limiting the number of useful offers that come in.

Winning offers in any RFO should meet the identified needs in a LCBF manner. Cost-effectiveness is established by comparing the net cost of the resource to other preferred and conventional alternatives. Further, the evaluation should be done on a portfolio basis. The identified needs reflect the specific operational characteristics that a *portfolio* of procured resources must exhibit.

Rather than consider each resource on a stand-alone basis, it is more appropriate to consider the desired attributes of the overall *portfolio* of procured resources. Therefore, required attributes of individual resources should not be fixed in time, independent of the specific need being met. Some resources will be more effective than others in contributing to an overall portfolio's ability to meet the identified needs. To determine the effectiveness of a proposed resource to meet the identified needs, it is preferable that resources be considered as a portfolio, rather than on an individual, stand-alone basis.

iv. How should cost allocation issues be addressed?

The cost allocation mechanism ("CAM") construct currently in place can accommodate contracts for repowering or upgrading of facilities. In other words, to the extent that an upgraded or repowered facility provides system or local benefits, the costs and benefits associated with the facility should be allocated to all benefitting customers (*i.e.*, bundled, DA, and CCA).

v. How would bilateral negotiations for upgraded or repowered facilities be reviewed?

For the purposes of this response, PG&E uses the term "bilateral" to refer to transactions where negotiations take place in a one-on-one setting outside of a competitive solicitation. Commission procurement rules dating back to 2002 allow short-term bilateral transactions subject to a strong showing. Short-term is defined as three months or less. However, it is highly unlikely that a facility owner would pursue a short-term contract for an upgraded or repowered facility. Since transactions for upgraded or repowered facilities are expected to exceed three months in duration, the current Commission procurement rules, as reflected in PG&E's BPP, would require a competitive solicitation unless the transaction is for a non-standard product. Utilities are permitted to enter bilateral transactions for non-standard products less than five years in duration subject to a strong showing. All other bilateral transactions (e.g., for a standard product longer than three months or a non-standard product of five years or more) must be submitted to the Commission for approval through an application process.

4. **Specification of the Rules that, if Followed, Would Allow the IOUs to Execute Bundled Procurement Contracts Without Additional Review by the Commission**

    a. **Please comment on the following potential new or modified rules to ensure competitive bundled procurement transactions:**

        i. **The IOUs must submit an advice letter or application if they follow their established AB 57 bundled procurement plan authorization, and**

            1. **The contract unit price is higher than a particular percentage (such as 80%) of the CAISO Capacity Procurement Mechanism or other administratively or market established price,**

            2. **The RFO did not attract sufficient participants, or**

            3. **The total megawatts (MW) procurement is over a specified level of MW.**

These proposed rules, which appear directed at determining whether a transaction was competitively priced, would only impact shorter-term transactions, those with durations less than five years, as transactions with durations five years or greater must already be submitted to the Commission for approval through an application process. These proposed rules are not necessary. The Commission's existing procurement directives, as reflected in the IOU's procurement plans, currently provide sufficient process and protection to ensure competitive results. Thus, rules requiring added review and approval by the Commission would be duplicative, add significant delay to the procurement process, increase procurement costs, and could affect the reliability of the electric system.

As noted above, these proposed rules would duplicate existing Commission reviews. Under its BPP, PG&E reviews all transactions with duration greater than three months with its PRG, which is uniquely positioned due to its ongoing review of PG&E's procurement activities, to evaluate whether solicitations are robust and if proposed transactions are competitive with the current market. Also, solicitations seeking product with duration over two years are required to be developed and overseen by an IE which adds another level of review and oversight to the procurement process. Moreover, while the response to an RFO might not be robust, this does not mean that the prices received are not competitive or reflective of the current market. The existing PRG and IE review processes are sufficient to ensure the results are competitive. Lastly, procurement position and execution limits address the concern of procurement above a specific amount.

These proposed rules could also add significant delay to the procurement process, and increase procurement costs. Specifically, review of a transaction through a Tier 2 or Tier 3 advice letter rather than through the quarterly compliance report ("QCR") could add a minimum of sixty days to well over a year or more to the review timeline taking into consideration protest periods and replies in addition to the need for the Commission to issue draft and final resolutions for the Tier 3 advice letters. Lengthy regulatory review could increase costs as participants may increase their price to reflect the possibility of having to hold their offer open for a longer period of time. It also puts the IOUs at a disadvantage as other LSEs would have more flexibility to transact and market participants could preferentially sell to them rather than participate in a prolonged IOU RFO.

These proposed rules could also affect system reliability and lead to an increase in advice letter filings containing individual transactions with smaller notional values requiring review. The Commission is already burdened with a large number of transactions to review and approve. Adding an additional number of shorter-term transactions with these rules could either delay the effectiveness of a contract beyond the time it was needed to provide reliability services to the system, or require the IOUs to execute a short-term bridging agreement to accommodate the delay in review and approval. Either of these outcomes is undesirable. In summary, the proposed rules are not needed and would likely only add cost, and potential delay, to an already heavily regulated procurement process.

ii. Any bilateral contract for a facility that did not make the shortlist of an RFO or an offer that has subsequently been negotiated with the utility for longer than six months making the shortlist of an RFO must seek approval of the Commission through a Tier 3 advice letter or application.

This proposed rule, which would affect shorter-term transactions, is equally unnecessary. Current procurement rules significantly limit bilateral transactions and generally would not allow a bilateral transaction with a facility that did not make the shortlist of an RFO (outside the existing thirty-day post-RFO limit). Given the shorter-term nature of the procurement at issue, more than six months of negotiations since making the shortlist of an RFO is not likely and even if it were, the current PRG and IE reviews would be sufficient to ensure the offer pricing remained competitive. For these reasons, the proposed rules should not be adopted.

b. What rules are needed to determine whether an IOU transaction is reasonable and therefore does not require additional review and Commission action?

The current procurement process, including the requirements for Commission review of certain transactions, is sufficient. Therefore, no new rules are required.

5. Changes to the Commission's Adopted Cost Allocation Mechanism (CAM) per Senate Bill (SB) 695, SB 790, Decision 11-05-005 and Relevant Previous Decisions

a. Is the CAM currently implemented in a manner that is sufficiently transparent or least cost?

Yes.

CAM is currently used in two different contexts. First, CAM can be used to allocate generation costs to all benefitting customers consistent with Section 365.1(c) (also referred to as Senate Bill or "SB" 695).[16/] Second, CAM treatment has also approved for contracts entered

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16/ *See, e.g.,* D.11-05-005. For example, in D.10-07-045, the Commission approved CAM treatment for the Power Purchase Agreement ("PPA") entered into between PG&E and Marsh Landing Generating Station LLC for the Marsh Landing facility. *See,* D.10-07-045, Ordering Paragraph ("OP") 7 (approving partial settlement which included CAM treatment for Marsh Landing Facility).

into under the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement approved by the Commission in D.10-12-035. In terms of transparency and LCBF evaluation, the Commission has already enacted sufficient procurement rules, as described in more detail below, to ensure these objectives are met.

First, DA and CCA representatives are involved during each phase of the CAM process through their participation in a separately established CAM PRG. The CAM PRG members are allowed to participate in the review of CAM-related procurement activities. The DA and CCA representatives' participation in the CAM PRG ensures that the process is fully transparent, subject to appropriate confidentiality limitations consistent with Section 454.5(g). The need for CAM-eligible resources is often identified through the LTPP proceeding or, in the case of the QF/CHP Settlement, in the course of the Commission proceeding approving that settlement.

When CAM-eligible resources are to be procured, CAM PRG members, including CCA and DA representatives, participate in the entire procurement process, including reviewing RFO documents before they are issued, reviewing RFO offers and shortlisting, monitoring RFO negotiations, and being informed of the final, winning RFO offers. These CAM PRG members have access to confidential information so that the process is completely transparent. The Commission has already adopted rules for how the CAM PRG members should participate in the procurement process.[17/]

In PG&E's recent RFOs where CAM resources were being procured, CCA and DA representatives actively participated in the process. For example, the CAM Group was actively involved in PG&E's 2008 LTRFO, which resulted in the Marsh Landing PPA, and have actively been involved in PG&E's QF/CHP Settlement RFOs.

In addition to the involvement of the CAM Group in the procurement process, CCA and DA parties are also actively involved in Commission proceedings reviewing CAM-eligible projects. For example, CCA and DA parties were actively involved in A.09-09-021 to review

17/ D.07-12-052, Appendix D (adopting rules for CAM Group participation in the procurement process).

the Marsh Landing PPA and have filed numerous comments on winning offers from PG&E's QF/CHP Settlement RFOs. Moreover, pursuant to D.11-07-028, CCA and DA parties, which are defined as market participants, can gain access to confidential information in these proceedings through an appropriate reviewing representative. Thus, although there are some appropriate limitations on the disclosure of confidential materials, DA and CCA parties have appropriate levels of access and input into the CAM process.

Second, with regard to a LCBF evaluation, CAM-eligible resources are subject to the same evaluation process as resources that are procured solely for PG&E's bundled customers. RFO evaluations and protocols are reviewed by the Energy Division, PRG, and CAM Group before the RFO is issued. All of the resources in an RFO are evaluated based on the same LCBF criteria. There is no differentiation between CAM-eligible resources and resources intended only for bundled customers. Thus, there is no need to change the current CAM procurement rules with regard to the LCBF issue.

b. Should the Commission reform the CAM energy auctions? If so, how?

To date, PG&E has not conducted an energy auction under CAM. However, it is PG&E's understanding from reviewing SCE filings in which CAM energy auctions were held is that the CAM energy auction process is time-consuming, costly, and results in few, if any, benefits for bundled, CCA and DA customers.

SB 695 specifically included language that an energy auction shall not be required.[18/] In the 2010 LTPP proceeding, PG&E and San Diego Gas & Electric Company ("SDG&E") advocated for elimination of the energy auction process, consistent with the clear statutory language of SB 695.[19/] In D.11-05-005, the Commission noted that there was ambiguity in the statutory language and determined that the Commission should retain the authority to decide when an energy auction is appropriate, and when it is not.[20/]

18/ Public Utilities Code § 365.1(c)(2)(C).
19/ D.11-05-005 at p. 12.
20/ *Id.* at pp. 12-14.

Given the empirical results of energy auctions to date, PG&E renews its request that the energy auction process for CAM be eliminated. For both the Marsh Landing PPA and the QF/CHP Settlement, the Commission approved a net cost allocation methodology that determined the net capacity costs of specific contracts without the need for an energy auction.[21/] This methodology should be employed for all CAM-eligible resources and the energy auction should be eliminated. Given the poor results to date of the energy auction process, this proposal would benefit DA, CCA, and bundled customers by eliminating the time-consuming, costly and unnecessarily complicated energy auction process.

c. How does the capacity allocation interact with other allocated costs such as energy efficiency and demand response funding?

Under CAM, bundled, DA and CCA customers are allocated the costs and the benefits of CAM-eligible contracts. In particular, DA and CCA customers are allocated RA (*i.e.*, capacity) benefits associated with CAM-eligible resources. This question is unclear as to what it means for the allocation of capacity benefits to "interact" with costs associated with energy efficiency and demand response costs. Energy efficiency and demand response costs are not allocated using CAM. Any associated benefits of DR and EE are allocated in proportion to those customers who pay for those programs. PG&E sees no interaction or cross-over between the CAM costs/benefits and EE and DR program costs/benefits.

d. At what stage in procurement should procurement be deemed CAM eligible, and what criteria should govern a Commission decision regarding CAM allocation?

Section 365.1(c)(2)(A) provides in part that the Commission will:

> Ensure that, in the event that the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's

21/ *See* D.10-07-045 (adopting net capacity cost methodology adopted for the Marsh Landing Facility); QF/CHP Settlement, Term Sheet Section 13.1.2.2 approved in D.10-12-035 (addressing net capacity cost calculation for QF/CHP Settlement PPAs).

> distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission . . . .

The Legislature provided latitude to the Commission as to the timing of the determination of whether procurement is CAM-eligible. Section 365.1 simply requires that the Commission authorize in the case of third-party generation, or order with regard to utility-owned generation ("UOG") facilities, that the generation resource be obtained to meet a system or local reliability need. This authorization or order can occur in the context of a general determination of need, which occurred in Track 1 of this proceeding where the Commission determined a general resource need that was CAM-eligible,[22/] or can occur when the Commission is reviewing a specific PPA or proposed UOG facility, such as recently occurred for SDG&E.[23/] The Commission should not limit itself to only determining CAM eligibility at a specific point during the procurement process. Instead, the Commission should maintain flexibility to consider CAM eligibility either as a part of a general procurement proceeding, such as the LTPP, or in the context of a specific PPA or proposed UOG facility. In either case, the Commission is authorizing or ordering procurement and thus, consistent with the statutory language, a determination of CAM-eligibility can be made.

e. How should the Commission address flexibility in regards to CAM? For example, should resources built in one IOU's service territory spread costs across all California Public Utilities Commission's jurisdictional load-serving entities?

The Commission should address flexible CAM-eligible resources in the same way it addresses other reliability needs in regards to CAM, as is required under Section 365.1. The net capacity costs of the CAM-eligible resource are to be allocated to all Commission-jurisdictional LSEs in the distribution service territory of the IOU that the Commission orders to procure the CAM resource.

22/ D.13-02-015, OP 15 (approving CAM-eligibility for procurement to meet local reliability needs in Southern California).

23/ D.13-03-029, OP 6-7 (approving CAM-eligibility for a specific PPA).

Under Section 365.1(c)(2)(B), when the Commission orders an IOU to procure CAM-eligible resources, it must determine that "those resources meet a system or local reliability need in a manner that benefits all customers of the electrical corporation." Further, under Section 365.1(c)(2)(A), the net capacity costs are to be allocated on a nonbypassable basis to that IOU's bundled customers, as well as the DA and CCA customers in the distribution service territory of the IOU ordered to procure the CAM-eligible resource.

Therefore, with respect specifically to flexible CAM-eligible resources, the Commission must determine that the flexibility need being met by the resource is a system or local reliability need, and that the resource meets that reliability need in a manner that benefits all customers of the IOU being ordered to procure it. If that is the case, the net capacity costs are to be allocated to the bundled, DA, and CCA customers in the distribution service territory of the IOU ordered to procure the resource, and not to the bundled, DA, and CCA of customers in the distribution service territory of other IOUs.

f. Should the CAM rules be differentiated to best account for benefit and cost allocation among community-choice aggregators and electric-service providers, based on their different business models or portfolio of other contracts? If so, how?

When it adopted Section 365.1(c), the Legislature did not create an exception for allocation of CAM-eligible costs based on a CCA's or energy service provider's ("ESP") business model or portfolio of contracts. Instead, to the extent the Commission authorizes or orders a specific resource to meet a system or local reliability need, these costs are allocated to all bundled, CCA and DA customers on a "fully nonbypassable basis." If a CCA or ESP could avoid these costs simply by claiming that it had a different business model or portfolio of contracts, the costs would not be "fully nonbypassable." Adopting an exception from CAM cost allocation because a CCA or ESP has a different business model or portfolio is contrary to the clear language of Section 365.1(c)(2)(A).

Moreover, even if the statutory language were not clear, which it is, there is no reasoned basis for excluding CCA or DA customers from CAM-eligible costs simply because the CCA or

ESP has a different business model or portfolio. If CCAs and ESPs are given an opportunity to avoid cost responsibility by claiming that they have a different business model or portfolio, it is likely they will make this claim, requiring Commission review of each CCA and ESP's business model or portfolio to determine if there is any basis for an exception from CAM cost allocation. With no objective criteria existing to make this determination, this will likely result in protracted litigation concerning the type of business model or portfolio that would be eligible for a CAM cost exception, and then further litigation regarding whether a specific CCA or ESP has that business model or portfolio.

6. Energy Resource Recovery Account Compliance Filing Requirements

a. Should the Commission require more consistency among the quarterly compliance reports (QCR) for the three major electric IOUs? If so, what areas of the QCRs currently lack consistency?

Although the issue of consistency between the IOUs' respective QCR filings was a topic PG&E had requested be considered in Track 3 of this proceeding,[24/] after thoroughly reviewing the scope and content of SCE and SDG&E's QCRs, and reviewing each of the other IOU's Annual Energy Resource Revenue Account ("ERRA") Compliance testimony, PG&E has concluded that the current format and content of the QCR submittals by the three IOUs are already consistent in keeping with the standardized QCR template implemented by Energy Division at the end 2008. Therefore, PG&E does not see a need to make changes to the QCR at this time.

The catalyst for PG&E introducing this topic was to address an audit finding PG&E received in a 2012 QCR review. Energy Division's audit team suggested that contract amendments are required to be filed for review in the QCR, pursuant to D.02-10-062, Appendix B[25/] and suggested that SCE and SDG&E routinely filed contract amendments for review in their respective QCRs.[26/]

24/ PG&E's November 2, 2012 comments on Track 3 issues.
25/ December 12, 2012, Division of Water and Audits Report on PG&E's 2nd Quarter 2012 QCR.
26/ D.06-12-009, Ordering Paragraph 3, issued in PG&E's 2005 ERRA Compliance Review Proceeding

The protocol all three IOUs follow in their respective QCRs is that each IOU reports contract amendments executed during the quarter in its QCR, and the amendments are reported in the information only table in Attachment H. Review of the contract amendment for approval, if applicable, is performed through a separate application, a separate advice letter or through the annual ERRA compliance review proceeding. Therefore, PG&E determined that the audit team was mistaken when they suggested that SCE and SDG&E routinely filed contract amendments in their respective QCRs.

All three IOUs' QCR filings follow a standard QCR template that was reformatted through collaboration between the IOUs and Energy Division in 2008, and all three IOUs' filings are materially the same.[27/] Prior to the standardization of the QCR template, the voluminous information that was included in the quarterly filings created a backlog of unapproved QCRs for all three IOUs. One of the goals of the QCR reformatting process was to not only to standardize the reporting requirements, but also to streamline the data presented to include only information necessary to be reviewed in QCR. This was accomplished by eliminating duplicative review processes so that the supporting materials included in the QCR were for transactions to be reviewed in the QCR.

All of that said, PG&E shares information about contract amendments with the audit team upon request. However, in keeping with the reformatted QCR template, PG&E does not include supporting information about the contract amendments in its initial QCR submittal.

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instructed PG&E *not* to file contract amendments in the QCR. Prior to the issuance of that decision, PG&E had included certain types of contract amendments for review in the QCR.

27/ The QCRs were originally mandated in D.02-10-062, Appendix B, as modified in D.03-06-076 where Appendix B was presented as a "Master Data Request." Subsequently, D.07-12-052 directed the Energy Division and the IOUs to continue the collaborative effort to develop a reformatted QCR. Decision 07-12-052 authorized the Energy Division to implement a reformatted QCR and to make ministerial changes to the content and format of the report as needs arise. The reformatted QCR was issued by the Energy Division at the end of 2008 and has been in use for four years.

b. Are any changes to information filed in QCRs necessary to ensure that IOU procurement is compliant with Commission rules?

No. As discussed above, after reviewing the other two IOUs' QCR filings and discussing the matter with SCE and SDG&E, PG&E has concluded that there is no inconsistency among the IOUs in the information presented in the QCRs.

c. Should the QCR evaluation process be moved from a quarterly evaluation to an annual, semiannual (or other term) process?

No. The quarterly cycle is the optimum in terms of ensuring the IOUs' transactions are expeditiously reviewed against the IOUs' Commission-approved procurement plan's upfront standards, consistent with Public Utilities Code Section 454.5(c)(3). The quarterly cycle also ensures the volume of information to be reviewed in the compliance filing is not overly burdensome to the Energy Division. Monthly filings would be burdensome to both the IOUs and the Energy Division but more importantly, could result in a more fragmented showing for certain transactions that may be initiated but not completed within a monthly cycle. On the other end, annual or semiannual transaction reviews would make for a more voluminous showing and could ultimately have a detrimental impact on the timeliness of the review and increase the burden on the Commission staff reviewing the filings.

7. Refinements to the Independent Evaluator Program

a. Please comment on the following proposal

i. The rules for whom or which entity may qualify to be in the IE pool remain the same

PG&E endorses keeping the current rules for IE qualification in place. Previous Commission decisions have addressed which procurement activities require an IE and this provides the framework regarding the qualifications and subject matter expertise an IE should possess.[28/] PG&E's BPP, Appendix I, describes in detail the process that is followed for selecting the IEs to be included in the IE pool, which allows the PRG and the Energy Division an

28/ Decisions 04-12-048, 07-12-052, and 12-01-033.

opportunity to comment and provide feedback regarding the qualifications of an IE in the pool and address the qualifications in relation to the requirements or needs of the procurement activity to which they are assigned. Ultimately, PG&E forwards a list of qualified IEs to Energy Division along with recommendations from the PRG, and the Energy Division is tasked with giving the final approval for an IE to be included in the IE pool.[29/] Thus, the current rules should meet the needs of the Energy Division and other members of PG&E's PRG.

ii. The IOUs may not limit the IE's interactions with the Commission, specifically in terms of nondisclosure agreements that restrict information sharing

iii. IEs are positioned on particular assignments through a random process, removing IOU influence over which IE may be assigned

Items ii and iii appear to be proposals in search of a problem. In PG&E's view, the current IE process is working well. If there are specific unaddressed concerns this proposal intends to address, PG&E is not aware of any particular situation that may have given rise them. This makes it difficult to determine whether these proposals would address the concerns or not.

Item ii implies that the IOUs limit the IE's interactions with the Commission. This is certainly not the case for PG&E. PG&E does not restrict the IE's interaction with the Commission or with the PRG and, in fact, IEs retained by PG&E have frequently communicated with the Commission or individual PRG members outside of the presence of PG&E employees.

With regard to confidential information, PG&E requires that the IE use Commission-approved procedures for ensuring that confidential information is not publicly disclosed. However, these procedures are no different than how PG&E itself handles confidential information. In either event, whether it is the IE or PG&E handling the confidential information, there is no restriction on the Commission and PRG members obtaining it. PG&E follows current Commission decisions regarding confidentiality and PG&E's IE NDA reflects the same standard.

29/ PG&E's Conformed BPP, Appendix I, Cal. P.U.C. Sheet 178.

With regard to item iii, IE assignments, PG&E reviews the expertise and strength of each IE, and also assesses the workload and availability of each IE. PG&E then recommends to the Energy Division a specific IE for a specific RFO, Request for Proposal, or other energy procurement activity requiring an IE, and describes the qualification of the IE and the characteristics of the assignment. The Energy Division has the opportunity to approve, ask for additional information, or ask PG&E to reassess or assign a different IE. The approval of the assignment rests with the Energy Division, and not with PG&E.

In addition, PG&E periodically updates and provides the opportunity for its PRG to comment on IE assignments and the IE pool. Both the Energy Division and the PRG may contact the IE if they have questions or concerns about the procurement activities assigned. Randomly assigning IEs would not take into account an IE's qualifications for a specific assignment, nor would it take into account the IE's availability or workload.

In sum, PG&E is not aware of any concerns or problems expressed by the Energy Division or the PRG with respect to IE assignments and thus, in PG&E's opinion, this proposal is unnecessary.

iv. IEs may remain in the selection pool for 10 years (rather than up to 6 years), subject to evaluation every 3 years (maintain current requirement for reassessment).

PG&E supports having an IE remain in the selection pool for ten years and subject to evaluation every three years. Procurement activities vary in length. Many procurement activities are complex in both subject matter and administration. Having IEs in the selection pool for a longer period of time allows the Energy Division, the PRG, and PG&E to assess the effectiveness of an IE for future consideration.

Additionally, this extension would give IEs more opportunity to cover a variety of procurement subjects and have a mix of assignments. It would also provide greater opportunity to rotate assignments among the IEs. PG&E's PRG also commented that they would like to assess a new IE in the pool by assigning the IE a smaller procurement activity before the IE is assigned a complex one (*e.g.*, RPS RFO). The PRG would like to evaluate how an IE performs before the IE is "stepped-up" to a larger and more complex procurement project. This proposal supports that, as well.

Respectfully Submitted,
CHARLES R. MIDDLEKAUFF
MARK R. HUFFMAN

By: *\/s/ Mark R. Huffman*
MARK R. HUFFMAN

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-6971
Facsimile: (415) 973-0516
E-Mail: crmd@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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