**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.13-12-010 (Filed December 19, 2013)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) PROPOSED 2014 BUNDLED PROCUREMENT PLAN

PUBLIC VERSION
(Redacted: Cover Pleading, Attachment A and Attachment C)

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(PUBLIC VERSION)

Pursuant to the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* ("Scoping Memo") issued in this proceeding on May 6, 2014, Pacific Gas and Electric Company ("PG&E") is submitting to the California Public Utilities Commission ("CPUC" or "Commission") for its review and approval PG&E's proposed 2014 Bundled Procurement Plan ("BPP"). This filing includes a cover pleading and three attachments. The cover pleading provides an overview of PG&E's 2014 BPP and a description of each section in or appendix to the BPP. The cover pleading also provides an explanation of how the 2014 BPP differs from PG&E's existing BPP which was approved by the Commission in Decision ("D.") 12-01-033, including substantive changes that PG&E has made in the 2014 BPP. In this pleading, PG&E's current, Commission-approved BPP is referred to as the "2010 BPP."

Attachment A provides a table that lists all of the sections in or appendices to the 2014 BPP, identifies the corresponding section or appendix in the 2010 BPP, and provides a brief explanation of changes or modifications that have been made in each section or appendix. Attachment A will allow parties to readily compare portions of the proposed 2014 BPP to PG&E's 2010 BPP. Attachment B includes a list of the substantive changes in the 2014 BPP for which PG&E is specifically requesting Commission approval. Finally, Attachment C is the proposed 2014 BPP. Because the 2014 BPP and this filing include market sensitive information under Public Utilities Code § 454.5(g), PG&E is submitting public and confidential versions of this filing and the 2014 BPP.

I. OVERVIEW OF THE PROPOSED 2014 BPP

Under Public Utilities Code § 454.5, California's investor-owned utilities ("IOUs") are directed to submit procurement plans that, once approved by the Commission, establish the up-front standards for IOU procurement activities and cost recovery. Because each IOU's procurement plan is for its bundled electric customers, it is typically referred to as a "Bundled Procurement Plan" or "BPP." PG&E's 2014 BPP is intended to achieve PG&E's goals to provide safe, reliable, affordable, and environmentally sensitive electric and gas service to its customers throughout northern and central California.

It has been four years since the IOUs last filed their BPPs, and while much of the energy industry in California has remained the same during that time, there have also been significant changes. Some aspects of PG&E's 2014 BPP filing are similar or identical to PG&E's existing 2010 BPP. For example, the list of approved procurement products and processes is relatively unchanged, as are specific procurement strategies, such as strategies related to convergence bidding. Other aspects of PG&E's BPP have been updated to reflect the passage of time or Commission decisions that have been issued during the last four years. For example, the discussion of PG&E's compliance with the loading order adopted by the Commission as a part of the Energy Action Plan ("EAP") has been updated to reflect significant developments in and Commission decisions affecting PG&E's Energy Efficiency ("EE"), Demand Response ("DR"), and Distributed Generation ("DG") programs. In addition, over the last four years, there have been substantial developments in the procurement of renewable resources and the implementation by the California Air Resources Board ("CARB") of California's ground-breaking Cap and Trade Program.

In addition to updates to reflect the passage of time, there are a number of important substantive changes in PG&E's 2014 BPP. These changes reflect the rapid evolution of the electric industry in California and throughout the United States. This evolution is being hastened by technological developments, regulatory decisions and requirements, and legislative initiatives. PG&E's 2014 BPP reflects a number of these key changes which have occurred in the last four years and impact PG&E's procurement activities. Below, PG&E highlights six key changes in its 2014 BPP, which include:

1. Significant structure and organization changes to the BPP to make it more streamlined, easy to use, and transparent;
2. The inclusion of PG&E's Alternative Scenario for its bundled electric forecast for the years 2015-2024 to reflect updated forecasts of departing load consistent with the Commission's direction in D.14-02-040;
3. The addition of electric energy, natural gas, and greenhouse gas ("GHG") compliance instrument procurement limits;
4. New appendices which address PG&E's scheduling and bidding practices in the California Independent System Operator ("CAISO") markets and PG&E's response to CAISO operating orders related to system reliability;
5. Changes to PG&E's electric portfolio hedging plan ("Hedging Plan") to reduce complexity, clarify compliance obligations, and address additional price exposure; and,
6. Changes to PG&E's nuclear fuel procurement plan given the substantial changes in the worldwide nuclear fuel market.

In addition to discussing these six key changes, this Overview section also addresses the issues raised in the Scoping Memo related to the BPP. After the Overview section, the remainder of this cover pleading provides a detailed description of each section or appendix in the 2014 BPP, and describes changes or updates to the 2010 BPP that are reflected in PG&E's proposed 2014 BPP.

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A. Structure and Organization of the BPP

PG&E's 2014 BPP substantially restructures the 2010 BPP to make it more streamlined, easy to use, and transparent. The structure and organization of the 2010 BPP dates back to 2006 and the Commission's 2006 Long-Term Procurement Plan ("LTPP") proceeding. The 2010 BPP structure reflects an outline developed in the 2006 LTPP proceeding, which, eight years later, needs to be updated and refreshed. The 2010 BPP includes sections and discussions on certain topics that are redundant or, in other cases, spread over multiple sections of the 2010 BPP. For example, rules concerning the Procurement Review Group ("PRG") and Independent Evaluators ("IE") are discussed in the body of the 2010 BPP and a separate appendix; these sections are redundant and have substantial overlap. Other topics appear in multiple places throughout the 2010 BPP. For example, there are numerous references in the body and appendices of the 2010 BPP describing how to update various portions of the 2010 BPP through an advice letter process.

The 2014 BPP has been restructured and reorganized to reduce redundancies, make it easy to locate materials, and to be more transparent. With regard to reducing redundancies, PG&E has reorganized the 2014 BPP to consolidate rules and discussions concerning specific topics in a single part of the BPP. For example, all of the rules regarding the PRG and IEs are now included in Appendix M. All of the sections in the 2010 BPP concerning updates through the advice letter process have been consolidated into a single discussion in Section VI of the 2014 BPP. The restructuring and consolidation of topics makes the 2014 BPP much easier to use; the Commission and parties will be able to go to a single section or appendix in the 2014 BPP to find information regarding a specific topic or issues, rather than having to look through the entire document for information.

In addition to eliminating redundancies, PG&E also restructured the 2014 BPP to make materials and information easier to find. For example, the approved products and procurement processes were embedded in a lengthy narrative discussion in the 2010 BPP. This information has now been put into two separate appendices – one for products (Appendix A) and the other for procurement processes (Appendix B) – so that they are easy to locate. PG&E has increased the number of appendices, and each appendix addresses a specific procurement-related issue or topic and so that it is easy for parties using the BPP to locate materials or information.

Finally, PG&E has restructured the BPP to increase its transparency. In the 2010 BPP, certain procurement-related topics were discussed without ready references to Commission decisions or rules. For example, PG&E's 2010 BPP included a narrative of the procurement-related filings that PG&E was required to make, but did not identify the Commission decisions or rules requiring these filings. A table has been added to Section IV of the 2014 BPP that lists PG&E's procurement-related filing requirements and the corresponding Commission decisions or rules. Similarly, Appendix M includes a table of all of the PRG, Cost Allocation Mechanism ("CAM") Group, and IE requirements and corresponding Commission decisions. Appendix M replaces the narrative discussion in Appendix I of the 2010 BPP that did not include specific references to Commission decisions. The 2014 BPP will allow parties to review the procurement-related rules and requirements listed in the BPP, and to compare these rules and requirements to specific Commission decisions.

B. PG&E's Alternative Scenario

In the 2010 BPP, PG&E included 10-year energy and capacity forecasts based on Commission-mandated assumptions and inputs. The 2014 BPP includes a similar forecast, referred to as the "CPUC Mandated Scenario," that provides 10-year energy and capacity forecasts based on assumptions and inputs mandated by the Commission for the 2014 LTPP proceeding.

However, there have been significant developments that have occurred since 2010 that are not completely reflected in the CPUC Mandated Scenario. To address these developments, PG&E is also providing the PG&E Alternative Scenario in the 2014 BPP. The PG&E Alternative Scenario differs from the CPUC Mandated Scenario in three key areas of the demand-side of the forecast: Community Choice Aggregation ("CCA"), Direct Access ("DA"), and DG. These differences are described below. There are no other substantive differences between the PG&E Alternative Scenario and the CPUC Mandated Scenario.

First, the PG&E Alternative Scenario reflects a higher amount of departing load for CCA. In recent years, the number of customers served by CCA has increased and there are now two active CCA providers in PG&E's service territory – Marin Clean Energy and Sonoma Clean Power. PG&E believes that there is substantial uncertainty regarding the amount of load that will depart for these and other possible CCAs and that the CPUC Mandated Scenario underestimates the amount of CCA departing load. Thus the PG&E Alternative Scenario has an increased forecast of CCA load departures. This is consistent with the Commission's recent direction in Decision 14-02-040 that PG&E estimate reasonable levels of expected CCA departing load.[1]

Second, the PG&E Alternative Scenario includes an updated forecast for DA load. Direct Access is currently capped by California statute and cannot be expanded without additional legislation. Thus, PG&E is not forecasting substantial increases in DA. However, PG&E has adjusted the DA load forecast in the PG&E Alternative Scenario as the DA load forecast in the CPUC Mandated Scenario is not based on the most recent DA load information.

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[1] D.14-02-040 at pp. 16-17 and Ordering Paragraph ("OP") 1.

Third, the PG&E Alternative Scenario reflects increasing load departure attributable to DG. As with CCA, there is substantial uncertainty regarding the levels of DG that will ultimately materialize. However, levels of DG, especially solar DG, are growing significantly in PG&E's service area and PG&E is currently forecasting substantial load reductions associated with the rapid expansion of DG. The PG&E Alternative Scenario reflects PG&E's current forecast of anticipated DG growth over the next ten years.

PG&E believes that its alternative scenario provides a more accurate forecast of PG&E's bundled procurement needs over the next ten years and thus is proposing that the Commission adopt the PG&E Alternative Scenario rather than the CPUC Mandated Scenario. In addition to the accuracy of the forecast, the PG&E Alternative Scenario raises a number of critical procurement and policy issues.

With regard to procurement issues, if the Commission adopts the PG&E Alternative Scenario, PG&E's forecasted bundled load will be substantially lower than the CPUC Mandated Scenario. A substantially lower forecast for bundled load has a direct impact on PG&E's procurement targets and limits. The consequential effect is that, to meet the needs of its bundled customers, PG&E would aim to procure less. In addition, a reduction in bundled load impacts the volume (annual gigawatt-hours (GWh)) of PG&E's Renewable Portfolio Standard ("RPS") requirements. Because a Load-Serving Entity's ("LSE") RPS requirements are based on a percentage of that LSE's load, a reduction in PG&E's forecasted bundled load reduces the volume of RPS-eligible energy that PG&E would aim to procure to meet its RPS requirements. However, PG&E still expects to be fully compliant with California's RPS requirements.

The PG&E Alternative Scenario also raises a number of key policy issues. These policy issues include: (1) which entities are responsible for long-term planning; (2) each LSE's procurement obligations to meet reliability need; (3) each LSE's procurement obligations to meet statutory and regulatory mandates; (4) cost allocation among LSEs; and (5) obligations to be the provider of last resort.

With respect to long-term planning, past and current practice is for the IOUs to be responsible for developing long-term resource and procurement plans to ensure reliable service and adequate supply in their respective service areas. Going forward, as PG&E's bundled load decreases and the load of other LSEs in PG&E's service territory substantially increases, the Commission and policy makers will need to carefully consider how to ensure that other LSEs in PG&E's service territory are making adequate long-term plans and entering into long-term procurement obligations to ensure sufficient supply and reliability. Long-term planning can no longer be solely the responsibility of the IOUs, especially as the load served by other LSEs increases.

Concerning cost allocation, past and current practice has assigned to the IOUs procurement obligations to meet long-term system reliability, local reliability, and some policy mandates on behalf of all customers in the IOUs' respective service territories. If the Commission requires an LSE to procure resources to meet a need beyond the load it is contracted to supply—whether that need is for system reliability, local reliability, or some policy goal—there must be equitable cost allocation to all LSEs. For PG&E, this means that the costs associated with any obligation PG&E would have to procure for non-bundled customers must be equitably allocated to the LSEs serving these non-bundled customers.

In addition, the Commission and policy makers may need to re-examine what are the obligations to be a provider of last resort for California electric customers. The Commission and California policy makers should consider how to ensure that all LSEs are prepared to reliably service their load on a long-term basis, and that there is appropriate compensation and cost recovery for entities that act as a provider of last resort. As the number of LSEs increase and the load served by non-IOU LSEs increases, re-examining issues concerning responsibilities and costs of being a provider of last resort is critical.

The Commission and policy makers also need to consider how responsibility for statutory and regulatory mandates will be applied going forward. Currently, many of the statutory and regulatory procurement-related mandates have been adopted for the IOUs only (or primarily), including programs such as the Renewable Auction Mechanism ("RAM") and Feed-In Tariffs ("FIT") for small renewable and combined heat and power ("CHP") projects. Many of these programs and mandates were adopted for the IOUs based on each IOU providing bundled electricity supply and electricity delivery to all but a small fraction of the total load in the IOU's service territory. As LSEs other than the IOUs supply a greater percentage of the load under the Commission's jurisdiction, these types of programs and mandates will need to apply to all LSEs, not just the IOUs.

The Commission and policy makers should carefully consider how policies intended to facilitate CCA, DA, and DG growth impact the procurement responsibilities and requirements in California. While the policy issues described above will not necessarily be addressed in Phase 2 of the 2014 LTPP proceeding, the PG&E Alternative Scenario vividly demonstrates the need to consider these issues expeditiously.

Finally, two additional issues related to PG&E's Alternative Scenario merit discussion. First, PG&E's Alternative Scenario is intended to be a long-term planning forecast and is not intended to be used as a shorter-term forecast for ratemaking or customer services in other proceedings or other similar uses. PG&E's Alternative Scenario is intended to consider potential trends over the next decade, not more immediate ratemaking or customer service or program issues in other proceedings that will be based on shorter-term forecasts. Second, PG&E's Alternative Scenario is a forecast and it includes a number of assumptions regarding events which may or may not occur. For example, PG&E is assuming that certain entities which have announced plans to form a CCA actually go ahead and form the CCA and serve customers. In some cases, events such as new CCAs forming or DG growth may not occur, or may occur at a less rapid pace than forecasted in PG&E's Alternative Scenario. If the Commission adopts PG&E's Alternative Case, PG&E intends to update its forecasts when it files advice letters to update the 2014 BPP procurement limits; these updated bundled load forecasts reflect updated circumstances, including events that actually occurred or did not occur.

C. Procurement Limits

In D.12-01-033, the Commission expressed strong support for the use of procurement limits in the IOUs' respective bundled procurement plans. As the Commission explained:

> As a general matter, this approach is reasonable – the Commission sets an upper boundary, and the utilities can procure up to that level without coming back to the Commission. This makes it easier for the Commission to find that the resulting rates are just and reasonable, as there is effectively a cap on procurement amounts and associated costs.[2]

In response to this direction, PG&E included electric capacity limits in its 2010 BPP. The Commission subsequently approved GHG procurement limits when it approved PG&E's proposed GHG Procurement Plan in D.12-04-046. Consistent with the Commission's direction, PG&E has expanded the procurement limits in the 2014 BPP to include electric capacity, electric energy, GHG, and natural gas procurement limits. These limits are included in Appendix C of the 2014 BPP and will be based on the forecast approved by the Commission, as described above (*i.e.*, either the CPUC Mandated Scenario or the PG&E Alternative Scenario). The proposed

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[2] D.12-01-033 at p. 7.

limits establish PG&E's procurement authority and ensure that procurement rates for PG&E's bundled customers are just and reasonable.[3]

D. Appendices Addressing Scheduling, Bidding, And CAISO Operating Orders

Since the IOUs resumed procurement responsibilities in 2003, the Commission has directed that the IOUs dispatch their resource portfolios in a least-cost manner. However, the IOUs' dispatch responsibilities changed significantly when the CAISO implemented its Market Redesign and Technology Upgrade in April 2009.[4] As the Commission recently explained, "[t]he regulated utility is responsible for scheduling and bidding its generation to the CAISO, but once that is done, it is the CAISO's responsibility to dispatch the generation."[5]

The 2010 BPP provided an overview as to how PG&E dispatched its owned and contracted resources. The 2014 BPP significantly expands this discussion and makes it consistent with recent Commission decisions which explain that PG&E is responsible for scheduling and bidding, and that the CAISO performs the actual dispatch.[6] In Appendix K, PG&E provides a detailed discussion of its scheduling and bidding principles, processes, and protocols for PG&E-owned and contracted resources. Appendix K explains how PG&E develops its bids and schedules for the CAISO, including considerations such as incremental costs and opportunity costs.

Appendix L provides protocols for PG&E's responses to specific CAISO Operating Orders associated with maintaining system reliability. Under its tariff, the CAISO can issue operating orders to PG&E and other market participants to address system emergencies,

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[3] *Id.*, Conclusions of Law ("COL") 1-4 (procurement limits help ensure that rates are just and reasonable under Public Utilities Code section 454.5).

[4] D.11-10-002, Finding of Fact ("FOF") 1.

[5] D.14-05-023, FOF 15.

[6] *Id.*

congestion, and overgeneration. These operating orders are generally the exception, rather than the norm, but it is likely that with increasing amounts of intermittent, inflexible renewable generation on the CAISO-controlled grid, situations involving system emergencies, congestion, and overgeneration may substantially increase in the future. Appendix L provides a description of how PG&E will respond to CAISO Operating Orders issued to address these operational situations.

E. Hedging Plan Changes

The Commission has approved utility hedging plans as a means of protecting customers from significant price spikes or swings in the market.[7] In the 2014 BPP, PG&E has proposed a number of changes to its existing hedging plan to simplify PG&E's hedging plan and address additional price exposure. The proposed changes will ultimately reduce the complexity of the hedging plan, clarify compliance obligations, and address additional price exposure. The specific changes to PG&E's hedging plan are described in more detail in Section XII below.

F. Nuclear Fuel Plan Changes

PG&E has revised procurement targets in its Nuclear Fuel Plan to reflect the fact that there have been substantial changes in the worldwide nuclear fuel market as a result of the Fukushima Daiichi incident in Japan and subsequent changes in nuclear generation worldwide as a result of this incident. The proposed revisions to the Nuclear Fuel Procurement Plan will allow PG&E [redacted] The Nuclear Fuel Plan runs through 2024 and ensures an adequate supply of fuel throughout the Diablo Canyon Power Plant ("DCPP") license period.

[7] D.12-01-033 at p. 25.

G. Scoping Memo Issues

The Scoping Memo identified four issues related to the BPP that are within the scope of this proceeding: (1) procurement limits; (2) approved products; (3) procurement rules; and (4) compliance with state policies including the loading order.[8] Each of these issues is addressed in the 2014 BPP. Procurement limits are addressed in Appendix C and approved products are addressed in Appendix A. Procurement rules are addressed in Sections I-VI and specific processes are addressed in Appendix B. In addition, PG&E's 2014 BPP includes a number of appendices that address specific procurement strategies, such as CRRs (Appendix I), GHG procurement (Appendix G), and convergence bidding (Appendix H). Finally, the 2014 BPP provides PG&E's integrated plan to comply with state policies, such as the loading order, by describing in detail PG&E's programs to implement the loading order (Section II) and the application of the loading order in procurement (Appendix B). In addition, the 2014 BPP also addresses other state policies such as once-through cooling (Appendix B), procurement of renewable resources (Section II), and compliance with California's rigorous GHG requirements (Appendices B, C, and G).

One issue that was not identified for this phase of the 2014 LTPP proceeding was safety. Establishing clear Commission rules and guidelines for how safety considerations should be integrated into the procurement process is important to provide clear, consistent direction to the IOUs as to how they should incorporate safety into their BPPs. Consideration of procurement-related safety issues will require substantial time and resources from the Commission and parties to develop a comprehensive and clear approach to safety. Therefore, PG&E recommends that the Commission establish a third phase of the 2014 LTPP proceeding that is solely focused on

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[8] Scoping Memo at p. 11.

how safety should be incorporated into the IOU procurement process, including consideration of how safety is used in the offer evaluation process and the assignment of responsibilities between generators and the IOUs for the safe operation of facilities. The Commission and parties would benefit from a third phase of this proceeding that is dedicated to safety issues.

II. SECTION I – INTRODUCTION

Section I of the 2014 BPP provides an introduction and a summary of PG&E's procurement goals, an overview of PG&E's planning, procurement and scheduling/bidding activities, and an overview of the remainder of the 2014 BPP. PG&E changed the term "dispatch" used in the 2010 BPP to "Scheduling/Bidding" to reflect the fact that the CAISO performs the actual dispatch of resources, and PG&E's role is to schedule and bid into the CAISO market.[9] In addition, PG&E significantly expanded the discussion of its Scheduling and Bidding practices by adding Appendix K to the 2014 BPP.

III. SECTION II – STATUTORY AND LOADING ORDER REQUIREMENTS

Section II of the 2014 BPP addresses statutory and loading order requirements and provides a summary of how PG&E complies with the requirements of Assembly Bill ("AB") 57 (*i.e.,* Public Utilities Code § 454.5) and the loading order adopted by the Commission as a part of the EAP. Sections II.B.1 through II.B.4 of the 2014 BPP update the descriptions of PG&E's EE, DR, RPS, and DG Programs that were included in the 2010 BPP. These updates reflect changes in Commission policies and Commission decisions that were issued after the 2010 BPP was approved. Section II.B.5 describes other generation resources available to PG&E after preferred resources are considered in procurement. Other generation resources were previously described in Section IV.F of the 2010 BPP. PG&E has shortened the discussion of other generation resources by deleting information that was duplicated in other parts of the BPP or was

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[9] D.14-05-023, FOF 15.

unnecessary. PG&E has also added a discussion of energy storage to this section to reflect the Commission's recent energy storage decision (*i.e.*, D.13-10-040).

In addition to these updates, PG&E deleted 2010 BPP Section IIA.1 which included a description of each of the departments in PG&E's Energy Procurement organization. The Energy Procurement organizational structure is not part of PG&E's AB 57 procurement authority and thus including the organizational structure in the BPP is not necessary. Therefore, this section was largely deleted, except for Section II.A.1.f concerning compliance with Standard of Conduct ("SOC") 2. Compliance with SOC 2 is now addressed in Section III of the 2014 BPP.

IV. SECTION III – COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT

Section III in the 2014 BPP addresses PG&E's compliance with the Commission's procurement-related SOCs. Table 3 in Section III of the 2014 BPP has been updated to reflect changed references to the location of applicable materials in the 2014 BPP. In addition, the summary of compliance for SOC 4 has been revised to indicate that the review of contract administration occurs in the annual Energy Resource Recovery Account ("ERRA") Compliance Review proceedings.

Section II.A.f.1 in the 2010 BPP, which addressed SOC 2, provided a link to a description of PG&E's ethics training. This discussion has been shortened to remove the link, as the link may change with time. Instead, Section III of the 2014 BPP simply states that PG&E's Energy Procurement employees are required to execute an electronic certification that they are aware of the Code of Conduct, and that these employees are required to complete a training course on an annual basis.

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V. SECTION IV – DESCRIPTION OF PG&E FILINGS MADE TO DEMONSTRATE COMPLIANCE AND COST RECOVERY

Section IV of the 2014 BPP describes the regulatory filings made by PG&E to demonstrate compliance with its Commission-approved BPP and the cost recovery that is authorized for generation resources procured in compliance with the BPP's upfront standards.

Section IV is a significant improvement to the 2010 BPP, which contained a lengthy narrative describing monthly, quarterly and annual procurement-related filings. Section IV.A of the 2014 BPP consolidates the lengthy 2010 BPP narrative into a single table which describes PG&E's procurement-related filings and provides a citation to the Commission decision(s) or statutory authority which requires the filing. This table provides an efficient and transparent means of summarizing PG&E's procurement-related filing and reporting requirements. PG&E added items to the table which had not been included in the 2010 BPP, such as the RPS Request for Offers Shortlist and Project Development Reports, the Annual RPS Plan, RAM and Photovoltaic ("PV") Program Reports, the Convergence Bidding Quarterly Report, and the Energy Storage Plan biennial filing. In addition, PG&E updated certain descriptions. For example, PG&E updated the description of the Resource Adequacy ("RA") Annual Report to include System, Local, *and* Flexible RA.

One item was deleted from the 2010 BPP discussion of filing requirements. The 2010 BPP included the LTPP proceeding as a PG&E filing. However, this is not a filing made by PG&E, but is instead a Rulemaking initiated by the Commission. Thus, PG&E deleted it from the 2014 BPP discussion of PG&E filing requirements.

VI. SECTION V – PRE-APPROVAL, APPROVAL, AND FILING REQUIREMENTS

Section V of the 2014 BPP describes the pre-approval, approval, and filing requirements associated with PG&E's procurement authority under the BPP.

PG&E has updated this section of the BPP to reflect the pre-approval requirements established by the Commission when an IOU's BPP includes procurement limits.[10] The 2010 BPP provided that PG&E could execute contracts that are less than five years in duration without Commission pre-approval, and that duration was determined either at the time the contracted resource begins *delivery* if delivery begins within one year of execution or at the time of contract *execution* if delivery occurs more than one year from execution. In D.07-12-052, the Commission determined that the pre-approval requirements are different for IOUs with procurement limits. Because the 2014 BPP includes procurement limits for electric energy and capacity, natural gas, and GHG compliance instruments, PG&E has changed the pre-approval language in the 2014 BPP to be consistent with the Commission's direction in D.07-12-052.

Section V of the 2014 BPP includes Table 5 which identifies different types of transactions and the corresponding filing requirement. This table is similar to the table in the 2010 BPP, but includes some updates and corrections to the appropriate venue for approval of certain transactions. Specifically, consistent with Commission decisions, non-RPS transactions with a contract duration of less than five years and Congestion Revenue Rights ("CRR") transactions are approved through the Quarterly Compliance Report ("QCR"), not through the annual ERRA Compliance application as indicated in the 2010 BPP.[11] Therefore, Table 5 in Section V of the 2014 BPP has been changed to indicate that these transactions are approved through the QCR, rather than the annual ERRA Compliance application.

In addition, PG&E clarified in Items #2 and #3 of Table 5 that form contracts that are pre-approved by the Commission do not require approval, such as the form contracts approved

[10] D.07-12-052 at p. 172 and OP 19.

[11] D.07-12-052 at p. 185 (describing QCR); D.04-12-048 at pp. 107-108 (approval of contracts less than five years through compliance filing and five years or greater through an application); Resolutions E-4135, OP 4 and E-4122, OP 4 (CRRs and Long-Term CRRs ("LT-CRRs") are included in QCR).

for the Feed-in Tariff Program and the RAM Program. PG&E also added Item #5 regarding the approval process for contracts arising from the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement and Item #6 to indicate the approval process for amendments to existing QF contracts.

VII. SECTION VI – UPDATES TO THE BUNDLED PROCUREMENT PLAN VIA ADVICE LETTER

Section VI of the 2014 BPP describes the process for updating PG&E's BPP between LTPP proceeding cycles. This section consolidates sections that were scattered throughout the 2010 BPP. Section VI also includes specific requirements for updates to PG&E's Electric Portfolio Hedging Plan, and provides that updates to PG&E's electric energy, electric capacity, and natural gas limits are filed annually (or more frequently if necessary) in a Tier 1 advice letter and PG&E's GHG compliance forecasts and purchase limits are filed as necessary in a Tier 2 advice letter.

In addition to consolidating sections from the 2010 BPP, PG&E deleted a paragraph from Appendix L, Section D.9 of the 2010 BPP that allowed PG&E to file an advice letter to update the GHG Procurement plan to reflect changes in market conditions, PG&E's electric portfolio, or CARB regulations. This sentence was redundant and simply repeated the general authorization for PG&E to file advice letters to update its BPP during LTPP proceeding cycles.

VIII. APPENDIX A – PROCUREMENT PRODUCTS

Appendix A of the 2014 BPP addresses PG&E's approved products. Most of the products identified in Appendix A have already been approved by the Commission. However, PG&E is proposing some modifications and additions.

For electric products in Table A-1 of the 2014 BPP, PG&E has made minor updates and corrections in product descriptions. Changes were made to the descriptions of Item #7 (Financial Call Option or Swaption), Item #8 (Financial Swap), Item #13 (Electricity Futures), Item #16

(Physical Call Options) and Item #24 (Non-Firm Transmission Rights Locational Swaps and Futures). In addition, Item #10 (Reliability Demand Response Resource) was renamed and Item #30 (Convergence Bids) was updated to reflect the fifteen minute market. These changes reflect more accurate product descriptions in accordance with recent industry developments and implementation of the Dodd-Frank Wall Street Reform and Consumer Protection Act. In addition, a new electric product was added to Table A-1 for Structured Transactions (Item #33). While this is a new product for PG&E's BPP, it was approved in D.07-12-052 for Southern California Edison Company's ("SCE") 2006 BPP, and in SCE's subsequent 2010 BPP.

Table A-2 lists PG&E's GHG products. These products were previously included in the electric products table and the GHG Procurement Plan, but have now been moved to a separate table within Appendix A.

For fuel products, PG&E has consolidated several products and made minor updates and corrections in product descriptions in Tables A-3 and A-4 of the 2014 BPP. First, Items #1 and #2 from Table II-2 of the 2010 BPP were consolidated into a single product which is now Item #1 in Table A-3 in the 2014 BPP. Purchases and sales of natural gas continue to be approved products within the 2014 BPP; the distinction "spot" natural gas that was used in Item #2 in the 2010 BPP is not necessary and is redundant. The description in Item #1 was also clarified.

Second, PG&E added distillate as a fuel product in Table A-3 of the 2014 BPP. PG&E's Humboldt Bay Generating Station primarily uses natural gas as a fuel source, but does use some distillate fuel for certain situations. Thus, PG&E added distillate fuel to the list of approved products. The recovery of distillate fuel costs for the Humboldt facility was approved in D.06-11-048, OP 17.

The last two changes to fuel products were to the descriptions of Item #1 and Item #2 in Table A-4 of the 2014 BPP. Similar to the changes made to Items #7, #8, #13, #24 in Table A-1 in the 2014 BPP for electric products, the descriptions of these two fuel products were updated to reflect recent industry developments due to the implementation of the Dodd-Frank Act.

For credit products in Table A-5, PG&E clarified that Credit Intermediation Arrangement (Item #3) may not be limited to just financial institutions as previously stated in 2010 BPP.

IX. APPENDIX B – PROCUREMENT PROCESSES AND METHODS

Appendix B of the 2014 BPP addresses PG&E's approved procurement processes and methods. Section B of this Appendix has been restructured to separate market processes (Section B.1), such as electronic solicitations and voice brokers, and Commission-mandated procurement programs (Section B.2), such as the RAM Program. Separating the procurement processes into market processes and Commission-mandated procurement programs provides greater clarity as to the source and requirements for a specific procurement process.

Section B.3 of the 2014 BPP describes the CARB auctions and allowance price containment reserve for GHG compliance instruments. This discussion was in Appendix L of the 2010 BPP (*i.e.*, PG&E's 2010 GHG Procurement Plan), but has been moved to Appendix B to consolidate the discussion of procurement processes and has been updated to reflect CARB's implementation of the auction process.

Table B-1 includes the addition of a "Cashout" process (Item #15). Although cashout transactions are generally characterized as direct bilateral purchases or sales of natural gas, PG&E added this item as a separate procurement process because the cashout process has important differences from most purchases or sales. Most importantly, a cashout is applied in accordance with a pipeline's tariff, and the volumes and prices may not be known until after the fact, when the pipeline invoices PG&E. Although pipeline customers, including PG&E,

typically try to avoid cashouts, they may be unavoidable in some circumstances due to the variable nature of gas demand for electric generation, among other factors. For example, if the CAISO dispatches a unit late in the evening unexpectedly, PG&E has no opportunity to adjust gas supplies because gas nomination deadlines have passed. Under certain balancing or flow order conditions, this may result in a cashout. Cashouts include such mechanisms that may use a variety of names, including standby procurement charge and buy-back rate, depending on the pipeline.

PG&E also added Item #16 in Table B-1, which addresses the process for bilateral transactions for natural gas storage and pipeline capacity. This process was approved by the Commission in D.03-12-062, COL 15, but had not been added to PG&E's 2010 BPP.

Finally, PG&E is seeking clarification of Item #10 in Table B-1. Specifically, PG&E seeks clarification that the limitation stating that electronic solicitations are approved only for "non-utility-owned resources" is not intended to bar transactions with PG&E California Gas Transmission for natural gas storage products. The limitation on utility-owned resources (in D.12-01-033, for example), clearly referred to "bids related to the development of utility-owned generation."[12] PG&E seeks clarification here to avoid a reading of this Item which might prevent the use of storage services provided by PG&E California Gas Transmission, for example. Bilateral transactions for storage products are allowed (Table B-1, Item #16), so a prohibition on electronic solicitations would be incongruous. Moreover, a transaction as simple and important to daily operations as a park or loan on a weekend, may be negotiated via electronic solicitation. PG&E seeks clarification that this process, which can be critical to managing daily gas balances, remains available to PG&E Electric Fuels.

[12] D.12-01-033, p. 42 (emphasis added).

Appendix B, Section D addresses Commission-adopted requirements for specific procurement processes. This section is a consolidation of several separate discussions in different portions of the 2010 BPP,[13] and also includes several new requirements that have been adopted in recent Commission decisions, such as requirements related to upgraded and repowered plants participating in LTRFOs (Section D.3) and the determination of the term of a contract (Section D.6).

X. APPENDIX C – PROCUREMENT LIMITS AND RATABLE RATES

Appendix C of the 2014 BPP addresses PG&E's procurement limits and ratable rates. The Commission endorsed the use of procurement limits and ratable rates in D.12-01-033 and in D.14-02-040. PG&E's 2014 BPP includes electric capacity limits, and new limits for electric energy, natural gas, and GHG compliance instrument procurement. The limits are addressed in detail below.

A. Electric Capacity and Energy Limits

PG&E's 2014 BPP includes three key changes related to electric procurement limits and ratable rates. First, PG&E made one modification to the methodology for electric capacity procurement limits in comparison to the 2010 BPP. For the purpose of calculation and compliance with electric capacity procurement limits, "planned preferred resources" was changed to also include procurement to comply with the Commission's Energy Storage Program targets (*see* Footnote 4 in Section A.1 of Appendix C). This change was made because procurement for the Energy Storage Program is already factored into the calculation of the

[13] Specifically, rules related to procurement of Once-Through Cooling resources that were located within Section II.A.7. of the 2010 BPP were moved to this Section D. Rules related to procurement of Utility-Owned Generation were moved into Section D from Section II.A.4.f. of the 2010 BPP. Rules related to procurement through Long-Term Request for Offers ("LTRFO") were moved from Appendix I, Section C of the 2010 BPP. A discussion of the loading order applicability to procurement was moved into this appendix from Section II.A.8.c of the 2010 BPP. A discussion of the evaluation and selection of resources through an RFO was moved from Section II.A.8 of the 2010 BPP.

electrical capacity procurement limits. Therefore, any procurement towards the Energy Storage Program targets will not count against the electrical capacity procurement limits.

Second, PG&E has added new procurement limits and ratable rates for electric energy. The calculation and compliance of PG&E's electrical energy procurement limits and ratable rates follow the methodology employed by SCE for energy procurement limits and ratable rates included in SCE's Commission-approved 2006 and 2010 BPPs, except for three modifications. The first modification is that PG&E's 2014 BPP includes just one overall net procurement limit for electric energy, rather than four separate limits (*i.e.*, for on-peak purchases, on-peak sales, off-peak purchases and off-peak sales). One overall procurement limit for electric energy achieves the Commission's objective of establishing procurement limits to assure just and reasonable rates[14], but with the added benefit of being much simpler to manage.[15] Another modification to SCE's electrical energy procurement limit methodology is a clarification with respect to what transactions count against the electric energy procurement limits and ratable rates. This clarification concerns paired transactions, locational basis contracts, and CRRs and was made to accurately capture transactions and avoid double-counting certain transactions against the procurement limits. The last modification to SCE's electric energy procurement limit methodology is a clarification indicating that the absolute notional volumes for all transactions will be used when counting against the procurement limits. This change was made in order to appropriately adapt the counting rules to the consolidated overall net procurement limit for electrical energy approach explained above.

[14] D.12-01-033, COL 1-2.

[15] The calculation of this procurement limit is detailed in Appendix C, Section A.2.

Finally, in Appendix C PG&E included calculated electric capacity and energy procurement limits for both the PG&E Alternative Scenario and the CPUC Mandated Scenario. The calculations of these two scenarios reflect the electric portfolios described in Appendix D.

B. Gas Limits

PG&E's 2014 BPP includes procurement limits and ratable rates for gas products in Appendix C.[16] The procurement limits, ratable rates, and calculation methodologies in PG&E's 2014 BPP match those employed in SCE's CPUC-approved 2006 and 2010 BPPs. The natural gas procurement limits in Appendix C replace the targets previously included in the 2010 BPP Gas Supply Plan ("GSP"). The limit structure identifies limits on gas procurement activities, while reducing complexity relative to the targets and goals of PG&E's 2010 GSP. PG&E's natural gas limits include limits for gas supply (*i.e.*, the natural gas commodity), pipeline capacity, and natural gas storage. These were the three elements of PG&E's Commission-approved 2010 GSP. Similar to the electric procurement limits, PG&E calculated gas procurement limits for both PG&E's Alternative Scenario and the CPUC Mandated Scenario described in Appendix D.

C. GHG Limits

Finally, Appendix C includes updated Direct Compliance Instrument Purchase Limits for 2015 and 2016 based upon PG&E's current GHG compliance instrument forecast. These GHG limits are the same for both the PG&E Alternative and CPUC Mandated Scenarios, since the same GHG-emitting resources existing within the electric portfolios of both scenarios.

Since the filing of the 2010 BPP, the uncertainty regarding the GHG Cap-and-Trade Program has declined and the market for GHG products has developed substantially. Thus,

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[16] The Electric Portfolio Hedging Plan in Appendix E establishes further limits and strategies for the execution of financial gas transactions (hedges).

PG&E has also included Financial Exposure Purchase Limits for 2015 and 2016 in its 2014 BPP. Financial Exposure (calculated in accordance with the Commission's approved methodology in D.12-04-046) estimates PG&E's indirect exposure to GHG costs embedded in the price of energy. PG&E will only use approved GHG Products provided in Appendix A to hedge GHG price risk that would be subject to these limits. Since the amount of energy to be purchased within the market varies between the PG&E Alternative and CPUC Mandated Scenarios, the Financial Exposure Limits of the two scenarios are different. Therefore, calculations for both scenarios are provided.

XI. APPENDIX D – DESCRIPTION AND EVALUATION OF CPUC MANDATED AND PG&E ALTERNATIVE SCENARIOS

Appendix D of the 2014 BPP provides a description and evaluation of two separate scenarios for bundled procurement needs between 2015 and 2024. The first scenario is the CPUC Mandated Scenario, which includes load and resource assumptions mandated by the Commission in the Scoping Memo. The second scenario, the PG&E Alternative Scenario, is based on the CPUC Mandated Scenario, but includes three demand-side modifications which impact the bundled load forecast. Both scenarios are described in more detail below.

A. CPUC Mandated Scenario

Appendix D includes a description and evaluation of the CPUC Mandated Scenario, similar to the description and evaluation of the Commission-mandated case in the 2010 BPP. The 2014 BPP incorporates the load and resource assumptions mandated by the Scoping Memo. Tables D-1 and D-2 provide the energy and capacity balances under the CPUC Mandated Scenario for the period 2015 to 2024.

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B. PG&E Alternative Scenario

The PG&E Alternative Scenario differs from the CPUC Mandated Scenario in three key areas. The three key areas all are on the demand-side of the forecast: CCA, DA, and DG. These differences are described below.

1. CCA Load Assumptions

PG&E developed its estimate of CCA load loss for the PG&E Alternative Scenario based on an evaluation of current activity levels for existing CCAs, as well as activity levels for entities that have engaged in an extensive analysis of CCA. PG&E recognizes that there is substantial uncertainty about the amount of CCA that will materialize and, as discussed in Section I.B above, these forecasts may need to be adjusted as events do or do not occur. Notwithstanding this uncertainty, PG&E believes that its estimate of CCA load loss is more reasonable than the CPUC Mandated Scenario estimate, given that the CPUC Mandated Scenario shows a level of load loss in 2024 for the combined categories of CCA and DA that is less than the current level of CCA and DA load. Specifically, the CPUC Mandated Scenario shows CCA and DA load combined in 2024 as 8,600 GWh per year, while existing DA load is about 9,600 GWh per year. The CCA load loss in the CPUC Mandated Scenario is not realistic in light of the load served by existing CCAs, much less the expected activity of those communities engaged in evaluating CCA. PG&E developed its CCA load forecast by estimating departing load based on the current load served by existing CCAs, combined with load that may be served by these entities, along with load that may be served by entities that are actively engaged in exploring CCA. PG&E's estimates are described in more detail in Appendix D.

2. Direct Access Load Assumptions

PG&E has taken the current amount of load served under DA (approximately 9,600 GWh per year) and has kept it flat throughout the forecast period. While PG&E implicitly agrees with the CPUC Mandated Scenario that DA load will be limited to current legislative limits, PG&E believes that maintaining DA load at current levels (as opposed to reducing these loads over time, as is done in the CPUC Mandated Scenario) is a more realistic estimate of DA load.

3. Distributed Generation Load Assumptions

PG&E forecasted PV adoptions by examining historical PV adoption rates, and adjusting growth projections based on anticipated policy developments. PG&E forecasted adoption of non-PV DG by the following technology categories: CHP, Fuel Cells, and Other. For traditional CHP and "Other" technologies, PG&E's forecast was developed using an historic 10-year average adoption rate. For fuel cell adoption, an exponential trend function, showing increasing rates of capacity addition, has been used.

By 2024, PG&E estimates that there will be approximately 12,100 GWh of generation from retail DG facilities, which equates to 13,300 GWh of avoided procurement at the point of generation (Table D-5, sum of lines 4 and 5). This compares to approximately 5,900 GWh of avoided procurement estimated in the CPUC Mandated Scenario (Table D-2, sum of lines 4 and 5). PG&E recognizes that there is substantial uncertainty as to the level of DG penetration that will occur. However, PG&E believes that its current forecast is more reasonable than the CPUC Mandated Scenario.

The CPUC Mandated Scenario for DG relied on the mid-case scenario from the 2014 California Energy Demand forecast developed by the California Energy Commission ("CEC"). A significant portion of the difference between CEC and PG&E forecasts is likely explained by different modeling approaches used by the CEC and by Bloomberg New Energy Finance ("BNEF"), whose forecast informed PG&E's projection. The CEC uses a modeling approach that is based on the United States Energy Information Administration's National Energy Modeling System model and the National Renewable Energy Laboratory's SolarDS model. The

CEC model predicts adoption based on consumer response to cost effectiveness as measured by a payback calculation.[17] This approach was developed when most PV systems were owned by host customers, and is likely to under predict how cost effective PV is for consumers now that third-party owned ("TPO") solar financing models are widely available. Under a third party ownership financing structure, cost effectiveness is more appropriately measured by comparing retail rates with prices that a third party solar provider can offer, given solar costs and profit margins.

BNEF uses an adoption model that measures cost effectiveness by comparing levelized bill savings against the levelized cost of solar. PG&E believes the approach used by Bloomberg better captures consumer decision-making under the current residential retail PV market environment in which third party financing models predominate. With TPO financing, the customer will have an economic incentive to install solar if bill savings are greater than the financing payment. Payback may not be the most applicable metric in this context.

Another difference between the PG&E Alternative and CPUC Mandated Scenario forecasts is that PG&E estimated an increase in installed MW associated with Zero Net Energy ("ZNE") policy, whereas the CEC did not. PG&E estimates that, starting in 2020, approximately 70 MW per year will be added as a result of California's ZNE policy goals.

4. Overlap Issues

To address any overlap that may exist between its load forecasts, PG&E subtracted from the CCA load departures described above the DA load percentage across the service area, and the estimated amount of DG growth within these communities. This estimated DG growth was

[17] California Energy Demand 2014-2024 Final Forecast Volume 1 Appendix B (January 2014), p. B-6.

derived by applying the DG growth rates to the current proportion of DG penetration that is located within the various communities that have implemented or are actively exploring CCA.

XII. APPENDIX E – ELECTRIC PORTFOLIO HEDGING PLAN

Appendix E includes PG&E's Hedging Plan. PG&E has proposed a number of substantive changes to its Hedging Plan that will reduce complexity, clarify compliance obligations, and address additional price exposure. Changes to PG&E's Hedging Plan are described in detail below.

A. Tenor

In context of the Hedging Plan, tenor means the length of the delivery period to be hedged. [redacted]

B. Hedging Targets and Limits

The hedging targets and limits in the 2014 BPP Hedging Plan are renamed and redefined from those in the 2010 BPP. The specific changes include the following:

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

C. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

D. Execution Strategy

[redacted]

E. [redacted]

[redacted]

F. Transition Plan

The Transition Plan in the 2010 BPP was intended to guide the transition from the 2006 BPP Hedging Plan to the 2010 BPP Hedging Plan. The Transition Plan is updated to guide the transition from the 2010 BPP to this plan. [redacted]

[redacted]

G. Unusual Events, market Dislocations and Emergencies

[redacted]

H. Liquidity Management Strategy

[redacted]

I. Deletions from the 2010 BPP

[redacted]

[redacted]

20 [redacted]

[redacted]

XIII. APPENDIX F – NUCLEAR FUEL PROCUREMENT PLAN

Appendix F includes PG&E's procurement plan for nuclear fuel used for DCPP. PG&E generally updated the tables and information in the plan to reflect the coverage of the plan from 2015 to 2024. In addition to these updates, PG&E made three substantive changes to the plan, which are described in detail below.

A. Forward Contracting and Price Terms

[redacted]

B. Nuclear Fuel Strategic Inventory

[redacted]

[redacted]

C. Proposed Risk Management Measures

[redacted]

XIV. APPENDIX G – GREENHOUSE GAS PROCUREMENT PLAN

Appendix G of the 2014 BPP addresses PG&E's GHG Procurement Plan. In the background section of Appendix G, PG&E included updates related to modifications of CARB's Cap-and-Trade regulation since the approval of the 2010 BPP. In particular, CARB expanded coverage of the Cap-and-Trade regulation in the second compliance period to cover suppliers of natural gas. Appendix G has been updated to indicate that the authority to procure for new natural gas-related obligations is being addressed in Commission Order Instituting Rulemaking ("R.") 14-03-003, and thus Appendix G only addresses those GHG compliance obligations related to PG&E's electric procurement activities.

In addition, Appendix G was updated to reflect CARB's approval on May 10, 2013 of the linkage with Quebec. Under this linkage, compliance instruments issued by CARB or Quebec are equally fungible and there is no way to identify what jurisdiction issued a particular compliance instrument. As such, PG&E modified the definition of allowances and offset credits to clarify that authorized compliance instruments are "*accepted*" by CARB rather than "*created*" or "*issued*" by CARB.

[redacted]

Finally, the GHG Procurement Plan in the 2010 BPP covered procurement for obligations related to GHG emissions from PG&E's natural gas compressor stations.[21] Subsequent to the approval of the 2010 BPP, authority to procure for GHG emissions related to PG&E's natural gas compressor stations was approved in D.13-03-017 and thus this procurement obligation no longer needs to be covered in the BPP. As such, references to emissions from PG&E's natural gas compressor stations have been deleted in the 2014 BPP.

XV. APPENDIX H – CONVERGENCE BIDDING

Appendix H of the 2014 BPP addresses Commission authorizations and requirements for PG&E's participation in the CAISO's convergence bidding market. PG&E has not made any substantive changes to the convergence bidding appendix approved by the Commission in the 2010 BPP. PG&E has updated Appendix H to reflect market design changes implemented by CAISO on May 1, 2014 (*i.e.*, new '15 minute market') and changes the reporting requirements. Monthly reporting requirements expired one year after the start of CAISO convergence bidding markets; the quarterly reporting requirements started with the Q1 2012 report.[22]

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[21] *See e.g.*, 2010 BPP, Sheet Nos. 287-288.

[22] *See* D.10-12-034, OP 7.

XVI. APPENDIX I – CONGESTION REVENUE RIGHTS

Appendix I of the 2014 BPP addresses PG&E's procurement of CRRs. PG&E made several substantive and non-substantive changes to the 2010 BPP in order to increase clarity and avoid repetition. First, the explanation of the analysis to identify candidate CRRs was updated and simplified. This analysis to determine the congestion cost and value of a CRR may be determined by transmission simulation studies, historical analyses, or a combination of both.

Second, PG&E eliminated the requirement to participate in CAISO auctions and the secondary market, making participation in both CRR-related procurement processes now optional.

Third, redundant language was eliminated. The CRR and LT-CRR sections were consolidated into one section. Duplicative language regarding the factors and measures which PG&E will rely upon to make CRR selection was provided once (rather than twice as in the 2010 BPP) and is applicable to both the CAISO allocation and auction processes. For example, the "Excess CRR" section in the 2010 BPP was removed since the authority to sell excess CRRs is covered in other areas of Appendix I: Auctions and Transactions in the Secondary Market.

Finally, PRG review of CRR procurement is now addressed in Appendix M and includes proposed changes to PRG review of CRRs. These changes are discussed in more detail in Section XX below. Section K in Appendix F of the 2010 BPP, which addressed cost recovery for CRRs, was deleted from Appendix I in the 2014 BPP to avoid a duplicative discussion of cost recovery for authorized products. In the 2014 BPP, cost recovery is addressed in Section V.

XVII. APPENDIX J – BROKERAGES AND EXCHANGES

Appendix J of the 2014 BPP addresses approved brokerages and exchanges. The list of approved brokers was updated to include the effective entity names for each broker (as of the filing date for this Pleading), to add one new broker, and to remove entities with which PG&E has ceased transacting.

In an effort to allow additional options for executing RPS-eligible transactions, PG&E requests to add the following broker to its existing list of Commission-approved brokerages the Finerty Group, Inc. Authorizing this addition to PG&E's list of approved brokerages does not obligate PG&E to use them. Instead, adding this broker will simply provide PG&E an option to do so. The decision to use this or any enabled brokerages in Appendix J will be made on a transaction-by-transaction basis. PG&E has routinely updated its list of brokerages and exchanges in order to add potential new counterparties for transactions that are consistent with PG&E's Conformed BPP. Further, should PG&E execute any RPS-eligible transaction through any brokerage on the list of approved brokers, PG&E will request Commission approval in accordance with the filing requirements provided in Section V of the 2014 BPP.

The following brokerage was deleted:

- Prebon was acquired by Tullett, which is already an approved broker list.

The following exchanges and futures commission markets were deleted:

- Green Exchange, LLC ("GreenX"), which was acquired by CME Group in 2012. CME Group also owns NYMEX, which is already listed as an approved exchange.

- Parity Energy, Inc., which ceased doing business on May 31, 2014.

There were three changes to Appendix J specific to GHG transactions. First, PG&E has clarified in footnote 1 that it only has authority to procure GHG products from brokerages though an RFO. Second, PG&E has noted in footnote 2 the requirements for requesting approval of new exchanges for GHG products as set forth by the Commission in D.12-04-046. Finally, to facilitate adherence to those requirements, PG&E has separately specified those exchanges that are authorized to transact GHG products.

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XVIII. APPENDIX K – BIDDING AND SCHEDULING PROTOCOLS

Appendix K of the 2014 BPP describes scheduling and bidding practices for the resources in PG&E's bundled portfolio. PG&E changed the term "dispatch" used in the 2010 BPP to "Scheduling/Bidding" to reflect the fact that the CAISO performs the actual dispatch of resources, and PG&E's role is to schedule and bid into the CAISO market.[23] PG&E significantly expanded the discussion of its Scheduling and Bidding practices in this Appendix. Appendix K provides an overview of the CAISO markets, describes the scheduling and bidding principles that PG&E utilizes to achieve least-cost dispatch ("LCD"), and describes the specific scheduling and bidding processes used by PG&E.

Section B of Appendix K provides an overview of the CAISO markets, including the day-ahead and real-time markets administered by the CAISO. These markets are fundamental to PG&E's scheduling and bidding practices, and the dispatch of PG&E's owned and contracted resources.

Section C describes the principles that PG&E uses for bidding and scheduling. These principles, while similar to the principles described in the 2010 BPP with regard to dispatch, have been expanded to include greater detail regarding PG&E's scheduling and bidding process.

Finally, Section D describes PG&E's scheduling and bidding process, including how PG&E develops the incremental costs for its bids into the CAISO markets, how GHG costs are factored into PG&E's scheduling and bidding, and the use of opportunity costs for certain resources such as hydroelectric resources and dispatchable renewable resources. This section also describes self-scheduling, which PG&E is required to use as a result of constraints on

[23] D.14-05-023, FOF 15 ("The energy regulated utility is responsible for scheduling and bidding its generation into the CAISO, but once that is done, it is the CAISO's responsibility to dispatch the generation.").

certain resource types, such as run of river hydro, and for certain types of contracts that cannot be dispatched, such as pre-2010 QF contracts.

The demonstration of compliance with the Commission's LCD requirements for a specific record year is addressed in PG&E's ERRA Compliance application.

XIX. APPENDIX L – CAISO OPERATING ORDER PROTOCOLS

Appendix L of the 2014 BPP describes PG&E's actions when responding to CAISO system reliability needs, such as system emergencies, congestion, or overgeneration, and provides protocols for PG&E's responses to specific CAISO Operating Orders associated with maintaining system reliability. Under its tariff, the CAISO can issue operating orders to PG&E and other scheduling coordinators to address system conditions. These operating orders are currently the exception, rather than the norm, but it is likely that with increasing amounts of intermittent, inflexible renewable generation on the CAISO-controlled grid, situations involving system emergencies, congestion, and overgeneration will increase in the future, and may increase substantially. The intent of providing this section is to provide transparency to the Commission and parties regarding PG&E's existing protocols and preparedness when responding to CAISO system reliability events and CAISO operating orders.

Section B of Appendix L describes PG&E's protocols for responding to CAISO declared system emergency events, including specific requirements for difference resource types.

Section C of Appendix L describes PG&E's protocols for responding to CAISO declared physical congestion events, including a description of the various actions the CAISO can take to manage the event. Section C also describes specific requirements for different resource types, along with a description of the approach PG&E uses to manage situations when the distribution of the generation reduction among units is not specified by the CAISO.

Finally, Section D of Appendix L describes PG&E's protocols for responding to CAISO-declared overgeneration events, including a description of the various actions the CAISO can take to manage the event. This section describes how PG&E responds to such conditions during different timeframes and depending on the resource type. Section D also provides a description of the approach PG&E uses to manage situation when the distribution of generation reduction among the units is not specified by the CAISO.

XX. APPENDIX M – PROCUREMENT REVIEW GROUP, COST ALLOCATION MECHANISM GROUP, AND INDEPENDENT EVALUTOR ADMINISTRATION

Appendix M of the 2014 BPP addresses the Commission requirements regarding the PRG, CAM Group, and IE administration requirements. PG&E consolidated three similar sections from the 2010 BPP (Section II.A.9, II.A.10, and Appendix I) into a single appendix in the 2014 BPP.

There is one substantive clarification that has been included in Appendix M. In Table M-1, Item #1, PG&E is requesting clarification that PRG review of each transaction greater than three months in duration executed according to a strategy previously reviewed by the PRG (but not part of a LTRFO) is not required prior to execution of the transaction. PG&E may review a procurement strategy with the PRG, such as a strategy for an RFO seeking products that are less than five years in duration. These types of RFOs are often based solely on price and winning offers are often executed within a short time after submission. In this situation, going back to the PRG to review each transaction would take time, and potentially result in lost opportunities. If PG&E has reviewed a procurement strategy with the PRG, then executes that strategy, it should not be required to bring each transaction back to the PRG for review prior to execution.

There are also several substantive changes that PG&E is proposing with regard to PRG review of CRR transactions. First, with respect to the annual CRR process, PG&E plans to continue to consult with its PRG prior to the start of the annual process. However, PG&E

proposes to change the PRG consultation to cover its CRR and LT-CRR position and overall procurement approach and strategy for the upcoming annual allocations and tiers. In Resolution E-4135, the Commission directed PG&E "to provide the PRG participants, prior to the PRG meeting, a list of proposed annual and long term CRR nominations for allocation and auction…"[24] PG&E has found this obligation impractical to implement. Similar to the time constraints applicable to the CAISO's monthly CRR process, there is limited time to identify and finalize a list of proposed nominations in advance of the PRG meeting. Additionally, the CAISO provides critical information needed to determine nominations only days in advance of the nomination submission dates. For example, limits on the node-pairs that can be nominated in the long-term process are released only five business days before the long-term nominations are due. Therefore, PG&E proposes this requirement be changed to allow PG&E to consult with the PRG prior to the start of the annual process regarding its CRR and LT-CRR position and approach for the upcoming process, and provide the PRG the full list of awarded CRRs and LT-CRRs after the conclusion of the annual process.

Second, in an effort to standardize the CRR reporting requirements to the PRG, PG&E is proposing the notification timeframe for all awarded CRRs from annual and monthly processes as well as all transactions in the secondary market be five (5) business days. Five (5) business days matches the timeframe the Commission has allowed SCE for reporting transactions from the monthly process. Changing the reporting deadline to five business days for all CRR awards and transactions simplifies and makes more consistent BPP implementation and compliance.

Third, PG&E proposes to review its CRR position with the PRG at least once per year. This is a clarification of the requirement that "directs PG&E to review its CRR position

[24] Resolution E-4135, p. 12

with the PRG in its periodic position update discussions…”[25] As noted above, PG&E will provide the PRG with numerous reports throughout the year with information regarding CRRs.

In addition to changes regarding CRRs, PG&E also deleted the *pro forma* consulting services contract for IEs that was attached to the 2010 BPP as Attachment 1 to Appendix I. Including a *pro forma* version of the consulting services agreement for IEs is not required by the Commission.

XXI. APPENDIX N – RISK MANAGEMENT POLICY AND TEVAR METHODOLOGY

Appendix N of the 2014 BPP addresses PG&E’s Risk Management Policy and TeVaR methodology. PG&E has updated this portion of the 2014 BPP in a number of areas. In Section A.3, PG&E has provided further clarification of the definition of investment grade based on the ratings provided by Standard and Poor’s (“S&P”) and Moody’s. PG&E specifically clarified the external rating levels that are reflective of investment level credit rating, which are BBB- by S&P or Baa3 by Moody’s. PG&E further clarified that it does not grant unsecured credit to counterparties that do not have an investment grade credit rating from the credit agencies or if PG&E’s internal evaluation does not support a credit rating equivalent of investment grade. Counterparties are instead requested to provide an appropriate amount of collateral for the transactions under consideration. In addition, counterparties which qualify for unsecured credit may still need to post additional collateral if the expected exposure is beyond the assigned credit limit.

In this same section, PG&E also clarified utilization of both its internal credit evaluation criteria and the external ratings to determine if a counterparty may qualify for unsecured credit with PG&E. The reason for this clarification is that not all counterparties have an external rating

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[25] Resolution E-4135, p. 12

and therefore internal credit evaluation by default is the only source for credit decision. In addition, credit ratings may not always reflect the latest financial disclosures or recent events. It is therefore important to highlight that credit decisions include both internal and external ratings, when available, for validation of overall assessment of creditworthiness.

PG&E has removed the specific dollar amounts associated with the various security requirements and instead retained the description for security amounts PG&E requires for the various financial and physical products. The reason for the removal of specific amounts is due to changes in security dollar amounts over time because of financial market conditions as well as market liquidity for a specific product.

PG&E has also clarified that it has incorporated collateral requirement for GHG products, both allowances and offset credits, in its bilateral agreements which were not in effect in 2010, but became effective starting in 2013. In addition, PG&E recognizes that for offset credits, there are additional invalidation risks that remain after receiving the offset credits. For this reason, PG&E requires a different amount of collateral after the delivery to specifically address invalidation risk for offset credits.

In Section A.3, because PG&E utilizes financial products for its hedging program, it must comply with the The Dodd-Frank Wall Street Reform and Consumer Protection Act which was enacted in July 2010. The 2014 BPP was updated to reflect this compliance obligation.

Finally, Table E-1 in the 2010 BPP, containing long-term forecast TeVaR values, has been moved to Appendix D in the 2014 BPP to be presented consistently alongside other forecast values from the same set of simulations.

XXII. APPENDIX O – ACRONYM LIST AND GLOSSARY

Appendix O is a list of acronyms and a glossary. PG&E has updated the acronym list and substantially reduced the glossary. The glossary in the 2010 BPP was 43 pages long and included many terms which are either no longer applicable to PG&E's procurement authority, or which are simply outdated. PG&E edited the glossary to delete terms which were irrelevant to the 2014 BPP.

XXIII. CONCLUSION

As PG&E has demonstrated above, the proposed 2014 BPP is consistent with California statutes and Commission decisions, reasonable, and will result in affordable procurement-related costs for PG&E's customers. PG&E respectfully requests that the Commission approve the proposed 2014 BPP, and, in addition, approve the specific substantive changes identified in Attachment B.

Respectfully submitted,

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By: * /s/ Charles R. Middlekauff*
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PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 3, 2014

ATTACHMENT A

2014 Bundled Procurement Plan (“BPP”) Sections, Corresponding 2010 BPP Sections, and Description of Changes

(Public Version)

2014 BPP SECTIONS, CORRESPONDING 2010 BPP SECTIONS, AND DESCRIPTION OF CHANGES

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
1	Section I – Introduction	Section I – Introduction (Sheet No. 1)[1]	Updated to reflect 2014 Long-Term Procurement Plan Rulemaking. Discussion of process for updating the BPP moved to Section VI.
2	Section I.A – PG&E's Procurement Goals	Section I.A – Overview of Procurement Activities Consistent with State Energy Action Plan (Sheet Nos. 1-4)	Updated to reflect PG&E's Procurement Goals, including safety, reliability, affordability and environmentally sensitive electric service.
3	Section I.B – Overview of PG&E's Planning, Procurement and Scheduling/Bidding Activities	Section II.A.2 – Overview of PG&E's Procurement Process (Sheet Nos. 15-17)	Updated descriptions of overview of procurement process. Section II.A.2.c of the 2010 BPP has been updated and moved into Appendix K.
4	Section I.C – Overview of PG&E's Bundled Procurement Plan	Section I.B – Overview of PG&E's Bundled Procurement Plan (Sheet Nos. 5-10)	Updated and shortened overview of the 2014 BPP.
5	Section II.A – Compliance with AB 57	Section VI.A – Compliance with AB 57 (Sheet Nos. 90-91)	Updated the BPP reference column to reflect sections in the 2014 BPP.
6	Section II.B – Compliance with the Loading Order	Sections II.A.8.c – Loading order Section IV (Sheet Nos. 48-49 and 67-85)	Updated to reflect new, Commission-approved programs to implement the loading order.
7	Section III – Compliance with Commission's Procurement Standards of Conduct	Sections II.A.1.f – Compliance with Commission Standard of Conduct #2 Section VI.B – Compliance with Commission's Procurement Standards of Conduct (Sheet Nos. 13-15, 91-93)	Updated discussion of Standards of Conduct for procurement and corresponding references in 2014 BPP.
8	Section IV.A – Monthly, Quarterly and Annual Filings and Reports	Section VI.C – Description of PG&E Filings Made to Demonstrate Compliance (Sheet Nos. 94-99)	Updated to reflect PG&E's procurement-related reporting requirements and a new table was added to reflect these requirements. Section VI.C.5.b (regarding the ERRA Trigger) was moved to Section IV.B in the 2014 BPP and Section VI.C.5.c from the 2010 BPP was deleted.

[1] Sheet No. references are to the most current version of the 2010 BPP, which is dated April 11, 2014.

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
9	Section IV.B – Additional Reporting Requirements – ERRA Trigger	Section VI.C.5.b – ERRA Trigger (Sheet Nos. 97-98)	Updated description of the ERRA Trigger Application.
10	Section IV.C – Description of Cost Recovery for BPP Procurement	Section VI.D – Description of Costs Recovered Through ERRA (Sheet Nos. 99-100)	Updated description to reflect changes since 2010 BPP, including deleting reference to the WaveConnect program which no longer exists.
11	Section V – Pre-Approval, Approval and Filing Requirements	Section VI.E – Pre-Approval, Approval and Filing Requirements (Sheet Nos. 100-102)	Updated the filing requirements for certain types of transactions and added additional filing requirements for existing QF contract amendments and contracts under the QF/CHP Settlement.
12	Section VI – Updates to Bundled Procurement Plan Via Advice Letter	Section I – Introduction (Sheet No. 1) Section II.A.6 – Electrical Capacity Procurement Limits and Ratable Rates (Sheet No. 44) Appendix B, Section E – Hedging Plan Updates Via Advice Letter (Sheet No. 133) Appendix D, Section B.3.c. – Updates to the Gas Supply Plan (Sheet Nos. 151-152) Appendix H, Section G – Future Convergence Bidding Strategies (Sheet No. 171) Appendix L, Section D.9 – Updates Via Advice Letter (Sheet No. 307)	Updated to consolidate discussions of BPP updating requirements that were described in various sections of the 2010 BPP.
13	Appendix A, Section A – Electric Products	Section II.A.3.a – Electric Products (Sheet Nos. 18-22)	Updated to reflect corrections and modifications in the product descriptions, and moved to new Appendix A. Added a new product “Structured Transaction.”
14	Appendix A, Section B – Greenhouse Gas Products	Section II.A.3.a – Electric Products (Sheet Nos. 18-22) Appendix L.D.2 –Greenhouse Gas-Related Products (Sheet No. 289)	Moved the GHG products from the Electric Product section in the 2010 BPP into a separate table in the 2014 BPP.

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
15	Appendix A, Section C – Fuel Products	Section II.A.3.b – Gas Products (Sheet Nos. 22-24)	Updated and clarified descriptions; merged two products from the 2010 BPP. Added distillate product, which is used for backup and startup fuel at one facility and was approved by the Commission in D.06-11-048.
16	Appendix A, Section D – Credit Products	Section II.A.3.c – Credit Products (Sheet Nos. 24-25)	Updated to reflect minor updates and corrections in the product descriptions.
17	Appendix B, Section A – Introduction	New Section – Not Applicable	New Appendix added to 2014 BPP.
18	Appendix B, Section B – Overview of Procurement Processes	Section II.A.4 – Overview of Energy Products Market (Sheet Nos. 26-33) Appendix L, Section A.2 – GHG Procurement Plan (Sheet Nos. 282-284)	Market and Commission-mandated processes separated into two subsections. Added a subsection regarding GHG compliance instrument procurement.
19	Appendix B, Section C -- Approved Procurement Processes And Practices	Section II.A.5 – PG&E's Procurement Methods and Practices (Sheet Nos. 33-35)	Updated process descriptions and added new transaction process for Cashout and Bilateral Transactions for Natural Gas Storage and Pipeline Capacity.
20	Appendix B, Section D – Commission Adopted Limitations for Specific Procurement Processes	Section II.A.7 – Contracting Rules for Once-Through Cooling Units (Sheet Nos. 44-46) Section II.A.5.f – Solicitations and Request for Offers (Sheet 31) Section II.A.8.c – Loading Order (Sheet Nos. 48-49) Appendix I, Section C – Request for Offer Process (Sheet Nos. 180-181) Section II.A.8 – The Application of Least-Cost Best-Fit and the Loading Order in PG&E's Procurement Processes (Sheet Nos. 46-48)	Updated to consolidate discussions of certain procurement processes that were in various sections of the 2010 BPP, and incorporate requirements from D.14-02-040.
21	Appendix C, Section A – Electric Limits	Section II.A.6 – Electrical Capacity Procurement Limits and Ratable Rates (Sheet Nos. 41-44) Appendix A – Table PGE-3 and PGE-4 (Sheet Nos. 106-107)	Updated electric capacity limits, added as new electric energy limits, and provided procurement limit calculations for a PG&E Alternative Scenario as well as for the CPUC Mandated Scenario.

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
22	Appendix C, Section B – Gas Limits	Appendix D – Electric Portfolio Gas Supply Plan (Sheets 147-152)	Updated to replace the Gas Supply Plan in the 2010 BPP and includes procurement limits for natural gas supply, pipeline capacity and storage. Provided procurement limit calculations for a PG&E Alternative Scenario as well as the CPUC Mandated Scenario.
23	Appendix C, Section C – Greenhouse Gas Limits	Appendix L.D.4.i – Maximum Volume Limits Appendix L.D.4.j – Financially Hedging Greenhouse Gas Compliance Instrument Price Risk (Sheet Nos. 300-305) Section V.C. – Greenhouse Gas Emission Evaluation (Sheet No. 89)	Moved from the GHG Plan into this appendix to allow all procurement limits to be covered in one area of the BPP. Updated to reflect the new plan duration and market changes, and provided Financial Exposure Purchase Limit calculations (in accordance with the methodology approved in D.12-04-046) for a PG&E Alternative Scenario as well as the CPUC Mandated Scenario. Direct Compliance Obligation Purchase Limits were also provided, but the calculation did not differ between the two scenarios.
24	Appendix D, Section A – Introduction	Section III – Description of Commission-mandated case (Sheet No. 61)	Updated to describe Appendix D (i.e., CPUC Mandated Scenario and the PG&E Alternative Scenario).
25	Appendix D, Sections B.1 and B.2 – CPUC Mandated Scenario Load Forecast and Existing and Planned Resources	Sections III.A and III.B – Load Forecast and Existing and Planned Resources for Commission-mandated Case Appendix A – Energy and Capacity Tables (Sheet Nos. 61-67, 104-105)	Updated to reflect the CPUC Mandated Scenario load and resource assumptions for the 2014 LTPP.
26	Appendix D, Section B.3 – CPUC Mandated Scenario Evaluation of Revenue Requirements, Rates and Risk	Section V – Evaluation of Commission-mandated Case (Sheet Nos. 86-89)	Updated to reflect the evaluation for CPUC Mandated Scenario.
27	Appendix D, Section C – PG&E Alternative Scenario		Adds the PG&E Alternative Scenario.
28	Appendix E, Section A – Introduction	Introduction (Sheet No. 109)	No substantive changes.
29	Appendix E, Section B – Hedging Plan Structure	Section A – Scope of the Hedging Plan (Sheet Nos. 109-111)	Updated text in the beginning of this section (i.e., Section A.1 regarding GHG has been moved to Section B.1.c and updated in reference to PG&E's GHG Plan) and the remaining subsections have only minor, non-substantive changes.

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
30	Appendix E, Section C.1 – Tenor	Section B.1 – Tenor (Sheet No. 112)	[redacted]
31	Appendix E, Section C.2 – Hedging Targets and Limits	Section B.2 – Operating Targets (Sheet Nos. 112-117)	[redacted]
32	Appendix E, Section C.2 – Hedging Targets and Limits	[redacted] (Sheet Nos. 117-119)	[redacted]
33	Appendix E, Section C.3.a – Product Mix Targets	Section B.3.a – Product Mix Targets (Sheet Nos. 120-122)	[redacted]
34	Appendix E, Section C.3.b – [redacted]	[redacted] (Sheet Nos. 122-123)	[redacted]
35	Appendix E, Section C.4 – Execution Strategy	Section B.4 – Execution Strategy (Sheet Nos. 124-125)	[redacted]
36	Appendix E, Section C.5 – [redacted]	[redacted] (Sheet Nos. 125-126)	[redacted]
37	Appendix E, Section D.1 – Transition Plan	Section C.1 – Transition Plan (Sheet Nos. 126-127)	[redacted]
38	Appendix E, Section D.2 – Unusual Events, Market Dislocations, and Emergencies	Section C.2 – Unusual Events, Market Dislocations, and Emergencies (Sheet Nos. 127-129)	[redacted]
39	Appendix E, Section E – Liquidity Management Strategy	Section D – Liquidity Management Strategy (Sheet Nos. 129-133)	[redacted]
40	Appendix F, Section A.1 – The Nuclear Fuel Cycle	Appendix C, Section A.1 – The Nuclear Fuel Cycle (Sheet Nos. 135-136)	Updated to reflect new information about the number of suppliers and customers for various portions of the nuclear fuel cycle.
41	Appendix F, Section A.2 – Diablo Canyon Power Plant Operations Plan	Appendix C, Section A.2 – Diablo Canyon Power Plant Operations Plan (Sheet Nos. 136-137)	[redacted]

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
42	Appendix F, Section B – PG&E's Nuclear Fuel Procurement Plan	Appendix C, Section B– PG&E's Nuclear Fuel Procurement Plan (Sheet Nos. 137-138)	[redacted]
43	Appendix F, Section B.1 – Forward Contracting and Price Terms	Appendix C, Section B.1 – Forward Contracting and Price Terms (Sheet Nos. 138-140)	[redacted]
44	Appendix F, Section B.2 – Nuclear Fuel Strategic Inventory ("SI") Management	Appendix C, Section B.2 – Nuclear Fuel Strategic Inventory Management (Sheet Nos. 140-141)	[redacted]
45	Appendix F, Section B.3 – Proposed Risk Management Measures	Appendix C, Section B.3 – Proposed Risk Management Measures (Sheet Nos. 141-142)	[redacted]
46	Appendix F, Section B.4 – Nuclear Liability and Insurance Issues Regarding Nuclear Fuel Contract	Appendix C, Section B.4 – Risk Issues Regarding Nuclear Fuel Contracts (Sheet Nos. 142-144)	[redacted]
47	Appendix F, Section B.5 – Capped Liability Under Some Contracts	Appendix C, Section B.5 – Suppliers Seeking to Contractually Cap Liability (Sheet No. 144)	Updated to incorporate title change and refine discussion.
48	Appendix F, Section C.1 – Regulatory and Political Outlook Not Specific to PG&E	Appendix C, Section C.1 – Regulatory and Political Outlook Not Specific to PG&E (Sheet Nos. 144-145)	[redacted]
49	Appendix F, Section C.2 – Transactions Outside the Scope of the Plan	Appendix C, Section C.2 – Transactions Outside the Scope of the Plan (Sheet No. 145)	No substantive changes.
50	Appendix F, Section D – Summary of Proposal and Conclusion	Appendix C, Section D – Summary of Proposal and Conclusion (Sheet Nos. 145-146)	[redacted]
51	Appendix G –GHG Procurement Plan	Appendix L – GHG Procurement Plan (Sheet Nos. 279-309)	Updated to reflect the following: (1) the plan only covers compliance obligations related to PG&E's electric procurement and (2) minor edits for the passage of time.

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
52	Appendix H – Convergence Bidding	Appendix G – Convergence Bidding (Sheet Nos. 166-171)	Updated to reflect market design changes and reporting requirement updates.
53	Appendix I, Section A – Introduction	Appendix F, Section A – Introduction (Sheet Nos. 157-158)	No substantive changes.
54	Appendix I, Section B – Congestion Revenue Rights and Long-Term Congestion Revenue Rights Procurement Objectives	Appendix F, Section B – Congestion Revenue Rights and Long-Term Congestion Revenue Rights Procurement Objectives (Sheet No. 158)	No substantive changes.
55	Appendix I, Section C – Congestion Revenue Rights Procurement	Appendix F, Sections C and D (Sheet Nos. 158-160)	Updated and reorganized (i.e., Sections C and D from Appendix F in the 2010 BPP have been merged into a single section in the 2014 BPP, and Section D.3 from Appendix F is now in Section D of the 2014 BPP.
56	Appendix I, Section D – Volume Limits	Appendix F, Section E – Volume Limits (Sheet Nos. 160-161)	No substantive changes.
57	Appendix I, Section E – Selection Criteria for Congestion Revenue Rights in Allocations and Auction Processes	Appendix F, Section F – Valuation and Risk Analysis (Sheet No. 161-162) Appendix F, Section G – Nomination Criteria in Congestion Revenue Rights Allocation Process (Sheet Nos. 162-163) Appendix F, Section H – Congestion Revenue Rights Auction Participation (Sheet Nos. 163-165)	Updated and reorganized (i.e., Sections F, G, and a portion of H from Appendix F in the 2010 BPP have been merged into a single section in the 2014.BPP in order to avoid redundancy so that there is just one overall explanation of the selection criteria for CRRs in allocation and auction processes..
58	Appendix I, Section F – Congestion Revenue Rights Auction Participation	Appendix F, Section H – Congestion Revenue Rights Auction Participation (Sheet Nos. 163-165) Appendix F, Section J – Excess Congestion Revenue Rights (Sheet No. 165)	Updated to reflect that participation in CRR auctions will be optional, as opposed to mandatory. This section F (of Appendix I) also clarifies actions PG&E may take to sell excess CRRs within the auction process.
59	Appendix I, Section G – Transactions in Secondary Congestion Revenue Right Market	Appendix F, Section H – Congestion Revenue Rights Auction Participation (Sheet Nos. 163-165) Appendix F, Section J – Excess Congestion Revenue Rights (Sheet No. 165)	Updated to reflect that participation in secondary markets will be optional, as opposed to mandatory. This section G (of Appendix I) also clarifies actions PG&E may take to sell excess CRRs within the secondary markets..

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
60	Appendix J – Brokerages and Exchanges	Appendix H – Brokerages and Exchanges (Sheet Nos. 173-173-A)	Updated to reflect the following: (1) the deletion and name change of several brokerages; (2) the name change of several exchanges; (3) specifically identifying those exchanges approved for GHG products, and (4) the addition of a new broker: Finerty Group, Inc.
61	Appendix K – Bidding and Scheduling	Section I.B.1 (Sheet No. 6) Section II.A.2.c – Dispatch (Sheet Nos. 16-17) Section II.A.5.a – Daily and Hour-Ahead Planning and CAISO's Real-Time Market (Sheet Nos. 38-40)	New Appendix added that incorporates and updates information regarding scheduling and bidding of PG&E's owned and contracted resources.
62	Appendix L – CAISO Operating Order Protocols	New Section – Not Applicable	New Appendix added, which was not included in the 2010 BPP, that describes PG&E's actions when responding to CAISO system reliability needs.
63	Appendix M, Section A – Procurement Review Group and Cost Allocation Mechanism Group	Section II.A.9 – PG&E's Use of the Procurement Review Group Process (Sheet Nos. 49-52) Appendix I, Section A – Procurement Review Group (Sheet Nos. 175-177)	Updated to reflect expanded discussion on the regular PRG and the CAM Group. Two tables were added to reflect Commission requirements associated with consulting and reporting to the PRG and CAM Group. Clarification requested to PRG review of transaction three months or greater (Table M-1, Item #1) and modifications to PRG review of CRRs and LT-CRRs.
64	Appendix M, Section B – Independent Evaluators	Section II.A.9 – PG&E's Use of the Independent Evaluators (Sheet No. 52) Appendix I, Section B – Independent Evaluators (Sheet Nos. 177-180, 182-222)	Updated to include Table M-3 which outlines the procurement activities requiring an independent evaluator and the associated directive.
65	Appendix N, Section A.1 – Portfolio Risk Assessment and Customer Risk Tolerance	Section II.B.1 – Portfolio Risk Assessment and Customer Risk Tolerance (Sheet Nos. 52-55)	Updated bundled system average rate and associated Customer Risk Tolerance consistent with the 10 percent risk tolerance factor for 2014 (see description of risk assessment and Customer Risk Tolerance).
66	Appendix N, Section A.2 – Current Risk Management Practices	Section II.B.2 – PG&E's Current Risk Management Practices (Sheet Nos. 55-56)	Updated the refine the discussion, but are no substantive changes were made.

Line No.	2014 BPP Section	2010 BPP Section	Description of Changes
67	Appendix N, Section A.3 – Credit and Collateral Requirements	Section II.B.3 – PG&E's Credit and Collateral Requirements (Sheet Nos. 57-60)	Updated to refine the discussion and categories of transactions were modified to reflect the passage of time.
68	Appendix N, Section B – TeVaR Methodology	Appendix E – PG&E's TeVaR Methodology (Sheet Nos. 154-155)	Updated by moving Table E-1 in Appendix E of the 2010 BPP to Appendix D in the 2014 BPP.
69	Appendix O – Acronym List and Glossary	Appendices J and K (Sheet Nos. 223-277)	Updated to reflect acronyms and relevant terms used in the 2014 BPP.

ATTACHMENT B

Substantive Changes for Commission Approval

Substantive Changes for Commission Approval

In its cover pleading, PG&E provides an overview of the 2014 BPP and described in detail changes between the 2010 BPP and the 2014 BPP. Many of the changes were updates to reflect the passage of time or events which have occurred since the 2010 BPP was approved. Other changes were substantive changes to PG&E's current procurement authority. In the table below, PG&E identifies the substantive changes to its procurement authority that were included in the 2014 BPP for which PG&E is requesting Commission approval. PG&E is requesting approval of the entire 2014 BPP, but is providing this table of substantive changes so that the Commission and parties can identify substantive changes for which Commission approval is requested.

Topic and Section of 2014 BPP	Summary of Substantive Change and request for Approval
Appendix A, Table A-1, Item #33 – Structured Transactions	Approve adding Structured Transactions product (this product has already been approved for SCE).
Appendix B, Table B-1, Item #10	Approve clarification that limitation on electronic solicitations for utility-owned resources does not apply to natural gas storage provided by PG&E California Gas Transmission.
Appendix B, Table B-1, Item #15 – Cashout	Approve the addition of a new procurement process for gas pipeline imbalances referred to as a "cashout"
Appendix C, Procurement Limit	Approve the proposed procurement limits for electric capacity and energy, natural gas (including natural gas supply, transportation and storage), and GHG compliance instruments
Appendix D, PG&E Alternative Scenario	Approve PG&E's Alternative Scenario and the corresponding capacity and energy balance tables as well as the corresponding procurement limits
Appendix E, Electric Portfolio Hedging Plan	Approved PG&E's revised Electric Portfolio Hedging Plan
Appendix F, Nuclear Fuel Procurement Plan	Approve PG&E's revised Nuclear Fuel Procurement Plan

Topic and Section of 2014 BPP	Summary of Substantive Change and request for Approval
Appendix G, Greenhouse Gas Procurement Plan	Approve PG&E's revised Greenhouse Gas Procurement Plan, which covers PG&E's obligations related to electric procurement (not its obligations as a natural gas supplier)
Appendix I, Congestion Revenue Rights	Approve PG&E's revised CRR procurement
Appendix J, Brokers	Approve the addition of a new broker -- Finerty Group, Inc.
Appendix K, Scheduling and Bidding Protocols	Approve new Appendix K
Appendix L, CAISO Operating Order Protocols	Approve new Appendix L
Appendix M, PRG consultation regarding transactions that are three months or more in duration	Approve the clarification proposed in Table M-1, Item #1 regarding PRG review of transactions three months or greater in duration
Appendix M, PRG review of CRRs	Approve the modified language in Table M-1, Item #9 and Table M-2, Item #12 regarding review of CRR and LTCRR transactions with the PRG
Appendix N, Risk Management Policy	Approve PG&E's revisions and clarifications to its Risk Management Policy

ATTACHMENT C

PG&E's Proposed 2014 Bundled Procurement Plan

(Public Version)

PACIFIC GAS AND ELECTRIC COMPANY
2014 BUNDLED PROCUREMENT PLAN
ORDER INSTITUTING RULEMAKING TO INTEGRATE AND REFINE PROCUREMENT POLICIES AND CONSIDER LONG-TERM PROCUREMENT PLANS

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I. Introduction

In accordance with the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, issued May 6, 2014 in Rulemaking ("R.") 13-12-010, Pacific Gas and Electric Company ("PG&E") is filing its Bundled Procurement Plan ("BPP") covering the period from the date the BPP is approved to December 31, 2024. PG&E's BPP will become effective on the date the California Public Utilities Commission ("CPUC" or "Commission") issues a decision approving the BPP and will remain in effect until December 31, 2024, or the BPP is superseded by a subsequent Commission-approved BPP, whichever is earlier. PG&E's BPP establishes the upfront achievable standards and criteria for PG&E's procurement activities and the recovery of procurement costs without an after-the-fact reasonableness review, consistent with California Public Utilities Code ("Pub. Util. Code") § 454.5.

A. PG&E's Procurement Goals

PG&E's goals are to provide safe, reliable, affordable, and environmentally-sensitive electric and gas service to its customers throughout northern and central California. The BPP is intended to achieve these goals for PG&E's bundled electric customers.

PG&E's first priority is safety. For PG&E-owned facilities, the focus on safety includes ensuring that PG&E's facilities are developed, maintained, and operated in a safe manner. PG&E has undertaken comprehensive safety efforts and has initiated a number of key safety programs to ensure that its hydroelectric, renewable, fossil-fueled, and nuclear facilities are maintained and operated in a safe and reliable manner. For contracted resources that are owned by independent third-party generators, local, state and federal agencies have review and approval authority over the generation facilities and are charged with enforcing safety, environmental and other regulations for the third-party facility. Safety for contracted resources owned by third parties is also addressed through the interconnection process, specific provisions in Power Purchase Agreements ("PPA") that address safety, and PG&E's construction monitoring process for new resources that are being developed. The specific operation and maintenance practices for PG&E-owned facilities or PPA safety provisions are not within the scope of the BPP. However, these activities are the foundation of PG&E's safety efforts for its owned and contracted energy resources and thus it is important to describe them in this overview.

Reliable service is also critical for PG&E's bundled customers. PG&E's BPP includes approved gas and electric products and processes which are intended to enable PG&E to maintain a reliable supply of electricity over the short-, medium- and long-term. PG&E's BPP is intended to ensure that PG&E is able to satisfy the Commission's Resource Adequacy ("RA") requirements, as well as other reliability and resource requirements adopted by the California Independent System Operator ("CAISO") to ensure a reliable supply of generation in California. PG&E's BPP describes in detail its planning, procurement, and scheduling and bidding processes, all of which are designed to enable PG&E to provide reliable, cost-effective bundled electric service. PG&E has also included a nuclear fuel supply plan to assure that nuclear fuel is available to allow for the continued, efficient operation of the Diablo Canyon Power Plant ("DCPP").

Customer cost is also a goal addressed by the BPP. In addition to procurement processes developed to get the best available market prices, PG&E's BPP also includes a hedging plan, use of convergence bidding and Congestion Revenue Rights ("CRR"), and a To-expiration Value-at-Risk ("TeVaR") methodology intended to effectively manage customer price risks. The BPP includes procurement processes and rules, many of which have been previously approved by the Commission, as a means of ensuring cost-effective procurement for bundled customers.

Finally, in addition to safety, reliability and affordability, PG&E's BPP incorporates and reflects California's progressive environmental policies. For decades, the California Legislature and the Commission have pioneered laws, regulations, and policies that have addressed critical energy and environmental issues and concerns. For example, on May 8, 2003, the Commission, California Energy Commission ("CEC") and the California Consumer Power and Conservation Financing Authority jointly issued an Energy Action Plan ("EAP")[1] for the state of California, outlining state energy and environmental policies and strategies. The EAP was updated in October 2005 and includes a preferred resource order to achieve California's energy and environmental policy goals: cost-effective Energy Efficiency ("EE") and Demand Response ("DR"), followed by renewable resources, including Renewables Portfolio Standard ("RPS")-eligible resources, Distributed Generation ("DG") and clean, efficient conventional facilities. California has also enacted legislation intended to reduce California Greenhouse Gas ("GHG") emissions and to promote renewable technologies.

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[1] The updated EAP is available at: http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf.

PG&E's BPP is designed to implement the EAP loading order and other environmentally-oriented procurement policies, while ensuring that PG&E's customers receive reliable and cost-effective service. In particular, the BPP describes PG&E's ongoing and significant efforts to spur continued investment in EE, develop cost-effective DR programs, and encourage the continued development of renewable resources. PG&E's BPP also incorporates the provisions of the Qualifying Facility and Combined Heat and Power Settlement ("QF/CHP Settlement") approved by the Commission in Decision ("D.") 10-12-035, which is designed to develop a Combined Heat and Power ("CHP") program that increases reliability and decreases GHG emissions.

B. Overview of PG&E's Planning, Procurement and Scheduling/Bidding Activities

PG&E's process for meeting the needs of its bundled customers involves three phases: planning, procurement, and scheduling/bidding. An overview of each of these three phases is provided below.

1. Planning

In the planning phase, PG&E identifies the resource needs of its bundled customers and plans to satisfy these needs consistent with the State Loading Order, EAP and other Commission and legislative directives to ensure safe, reliable, affordable and environmentally-sensitive electricity service.[2] PG&E identifies specific products to meet its customers' needs. These products include energy products (baseload, shaping, and peaking), capacity products to meet RA requirements, and various ancillary services products, including regulation, load following (i.e., balancing services), spinning,

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[2] PG&E also looks at the reliability and operational flexibility needs for its entire service area.

non-spinning, and black-start capability. Section II below provides further detail concerning the planning phase, as well as Appendices C and D.

2. Procurement

PG&E implements its Commission-approved BPP through various procurement methods and practices, including competitive solicitations, bilateral negotiations, and participation in various markets. PG&E enters into short-, medium-, and long-term contracts that result from the procurement process. PG&E defines short-term contracts as contracts with a term of one year or less; medium-term contracts as contracts with a term greater than one year, but less than five years; and long-term contracts are contracts with a term five years or greater. Renewable contracts are an exception to this rule, with anything under 10 years in duration being short-term for this contract category.[3] PG&E also has procurement plans for specific products, such as nuclear fuel and GHG compliance instruments. Appendix A provides more detail concerning the products that PG&E procures, Appendices B, E-J, and M-N provide more detail about procurement processes and specific procurement plans, and Appendix C provides the procurement limits for electric capacity, electric energy, natural gas, and GHG products.

3. Scheduling/Bidding

PG&E schedules and/or bids its owned and contracted resources into the CAISO day-ahead and real-time markets to achieve Least-Cost Dispatch (“LCD”). PG&E’s scheduling and bidding processes are described in more detail in Appendix K. In addition to its scheduling and bidding LCD activities, PG&E may at times receive operating orders

[3] See Pub. Util. Code § 399.13(b); D.12-06-038 at pp. 34-35.

from the CAISO to address certain events that may impact system reliability for the CAISO-controlled grid. In Appendix L, PG&E describes its responses to certain CAISO operating orders for system emergencies, congestion, and overgeneration.

C. Overview of PG&E's Bundled Procurement Plan

1. Section II – Statutory and Loading Order Requirements

Section II describes PG&E's compliance with Assembly Bill ("AB") 57 (Pub. Util. Code § 454.5) and PG&E's resource acquisition strategies for EE, DR, RPS-eligible resources, DG, conventional generation, and other generation including imports.

2. Section III – Procurement Standards of Conduct

Section III describes PG&E's compliance with the Commission's procurement-related Standards of Conduct (SOC).

3. Section IV – Compliance Filings and Requirements and Cost Recovery

Section IV describes the various monthly, quarterly, and annual filings made to demonstrate compliance with its approved plan and Commission policy and cost recovery under the BPP.

4. Section V – Pre-Approval, Approval, and Filing Requirements

Section V describes the pre-approval, approval, and filing requirements associated with procurement under the BPP.

5. Section VI – Process for Updates to the Bundled Procurement Plan

Section VI describes the process for updating the BPP between Commission proceedings.

6. Appendices

The BPP includes the following Appendices:

Appendix A	Procurement Products
Appendix B	Procurement Processes and Methods
Appendix C	Procurement Limits and Ratable Rates
Appendix D	Description and Evaluation of CPUC Mandated and PG&E Alternative Scenarios
Appendix E	Electric Portfolio Hedging Plan
Appendix F	Nuclear Fuel Procurement Plan
Appendix G	Greenhouse Gas Procurement Plan
Appendix H	Convergence Bidding
Appendix I	Congestion Revenue Rights
Appendix J	Brokerages and Exchanges
Appendix K	Bidding and Scheduling Protocols
Appendix L	CAISO Operating Order Protocols
Appendix M	Procurement Review Group, Cost Allocation Mechanism Group, and Independent Evaluator Administration
Appendix N	Risk Management Policy and TeVAR Methodology
Appendix O	Acronym List and Glossary

II. Statutory and Loading Order Requirements

A. Compliance With AB 57

AB 57 includes detailed requirements for an Investor-Owned Utility's ("IOU") procurement plan. PG&E's BPP fully complies with these requirements, as Table 1 below demonstrates:

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH AB 57

PUC Section 454.5(b) Requirements	Citation To PG&E's BPP
1. An assessment of price risk associated with PG&E's portfolio.	Appendices C, D, E, and N
2. Definition of electricity products, electricity-related products and procurement-related financial products, including justification and the amount to be procured.	Appendices A and C-I
3. The plan duration.	Section I
4. The duration, timing and range of quantities of each product to be procured.	Section II.B and Appendices B-I
5. A description of PG&E's competitive procurement process.	Appendices B, E, G, I, and J
6. Any proposed incentive mechanism.	Not applicable
7. The upfront standards and criteria for the acceptability and eligibility for rate recovery, and any expedited approval process.	Sections II-V and Appendices A-C, E-M
8. Procedures for updating the plan.	Section VI
9. A showing that the plan achieves: (a) the RPS standard; (b) a diversified portfolio of short-term and long-term electricity and DR products; and (c) meeting resource needs through all available energy efficiency and demand reduction when it is cost effective, reliable and feasible.	Section II.B and Appendices B and D
10. PG&E's risk management policies.	Appendix N
11. A diversity of ownership and fuel supply.	Section II.B and Appendices B-D, F
12. A mechanism for recovery of reasonable administrative costs related to procurement in the generation component of rates.	Section IV

B. Compliance With the Loading Order

According to the EAP, cost-effective EE and DR are preferred to meet California's growing energy needs, followed by cost-effective renewable and DG resources, and finally clean and efficient fossil-fueled generation. Pursuant to D.12-01-033, PG&E shall procure additional EE and DR resources to the extent they are feasibly available and cost effective.[4] This approach continues for each step down the loading order, including RPS-eligible resources and DG. The EAP also requires improvements to Transmission and Distribution ("T&D") systems to support demand growth and enable the interconnection of new generation.

PG&E's BPP is designed to implement the EAP loading order and legislative and Commission directives regarding procurement. The BPP balances three primary objectives: (1) assembling a portfolio of safe, reliable and operationally flexible resources; (2) preferred resources; and (3) managing customer price and price volatility. In this section, PG&E describes its resource acquisition strategies for: EE; DR; RPS-eligible resources; DG; and other generation resources, including Qualifying Facilities ("QF") and CHP, clean, efficient fossil-fired generation, non-RPS-eligible renewables, and imports. Many of the specific resource strategies are developed and approved in other Commission proceedings. Moreover, these strategies change over time. For example, EE and DR programs are typically reviewed every 2-3 years to determine if program changes are appropriate, or additional program measures can be implemented. The discussion below represents PG&E's implementation of the loading order when the BPP was filed in October 2014. The specific strategies and programs will change with time as they are further reviewed and refined by the Commission and parties active in these programs.

[4] D.12-01-033 at p. 21.

1. Energy Efficiency

a. PG&E's Long-Term Commitment to Energy Efficiency

PG&E has been, and continues to be, a key contributing partner to California's leadership in EE. In 1976, PG&E became one of the first utilities in the nation to offer EE programs to its customers. Since then, PG&E has helped customers save billions of kilowatt-hours (kWh) of electricity and has received numerous awards and recognition as a leader in the EE industry from organizations like ENERGY STAR, the American Council for an Energy Efficient Economy, and most recently Ceres/Clean Edge.[5] PG&E's longstanding commitment to EE has kept more than 180 million tons of carbon dioxide out of the atmosphere.[6] PG&E has been and continues to be supportive of the EAP "loading order" for energy needs in California, which places EE at the top of the list, followed by other demand-side resources and renewables. The California IOUs' EE programs have been a key contributor to meeting many of the state's long-term energy policy goals such as AB 32, the Global Warming Solutions Act.

b. PG&E's 2013-2014 Programs

PG&E's 2013-2014 EE portfolio is described in D.12-11-015 and PG&E's first (3356-G-A/4176-E-A) and second (3356-G-B/4176-E-B) supplemental advice letters. PG&E's 2013-2014 EE portfolio builds upon successes of prior EE programs and is designed to meet or exceed the goals established by the Commission in D.12-11-015. The portfolio delivers a comprehensive suite of EE rebates, incentives, services and tools for targeting customers through multiple delivery channels. These channels include

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5 http://www.ceres.org/press/press-releases/first-of-its-kind-report-ranks-u.s.-electric-utility-companies2019-renewable-energy-energy-efficiency-performance.

6 See http://www.pge.com/about/environment/pge/energyefficiency/index.shtml.

utility program staff, government partnerships, and third parties, including trade professionals, retailers, distributors, manufacturers, and designated third-party programs. The portfolio offers EE solutions to PG&E customers in every sector (residential, commercial, industrial, agricultural) and addresses every element of the EE product evolution: fostering emerging technologies; training the workforce; delivering and marketing products and solutions; providing financing options to customers; integrating EE offerings with other Demand-Side Management ("DSM") options; and working to move mature products to code.

c. Post-2014 Programs

For 2015 and beyond, California is exploring moving to a "rolling portfolio" process from the 3-year "cycle" process that has been used in the past. A "rolling portfolio" would establish firm funding for the long term (e.g., 10 years) with periodic portfolio adjustments and funding renewal. The primary objective of the rolling portfolio is to eliminate the "start-stop" nature of the programs and market activities which are currently tied to the regulatory calendar. The rolling portfolio would allow market activity to follow the normal business cycle and hence improve market efficiency.

The Commission has established a process for shifting to a rolling portfolio in R.13-11-005, which includes establishing funding for 2015 as an interim step while the rolling portfolio process is established. To date, savings goals for 2015 have been established, IOUs have submitted funding proposals, and a Commission decision on funding approval for 2015 is expected by the end of the year. PG&E's proposal is to largely continue 2013-14 programs, while supporting key state efforts and challenges like

Proposition 39 EE funding for schools, targeting of DSM programs to provide T&D deferral benefits, and offering solutions to reduce water usage in support of the state's response to the drought. PG&E's proposal will also meet or exceed state savings goals.

D.12-11-015 and R.13-11-005 included utility specific goals for the program cycles. The goals established for PG&E can be found in Table 2 below.

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
PG&E ENERGY EFFICIENCY GOALS FOR 2013 – 2015

Line No.	Metric ('13-'15 Program Cycle)	2013	2014	2015
1	**Electricity Savings (GWh)**			
2	IOU Programs	599	593	698
3	Codes and Standards Advocacy	254	239	283
4	**Peak Savings (MW)**			
5	IOU Programs	114	100	110
6	Codes and Standards Advocacy	31	32	44

2. Demand Response

DR is a valuable resource for managing PG&E's peak demand, improving system reliability through RA, avoiding or deferring costly capital investments, advancing SmartGrid goals, facilitating integration of intermittent renewable resources, providing customers alternatives to manage their bills and furthering the objectives of California's EAP. As such, PG&E has developed a portfolio of DR resources that are capable of furthering these goals. PG&E is committed to further enhancing its DR portfolio, in terms of capability, efficiency, flexibility and size.

a. PG&E's Adopted 2012-2014 Demand Response Programs

PG&E has a portfolio of roughly 650 megawatts ("MW") of DR programs that span a mixture of residential, commercial, industrial, and agricultural customers which either have a price-responsive (economic) or reliability-based (emergency) functionality. For its residential customers, PG&E runs an emergency dispatch program called SmartAC™ that can directly control customers' air-conditioning units in order to reduce load. PG&E operates another emergency dispatch program for 275 of its large commercial and industrial customers known as the Base Interruptible Program, with a total of 225 MW of potential load drop. In terms of economic dispatch, PG&E runs a Demand Bidding Program ("DBP") as well as two aggregator-managed programs—Capacity Bidding Program and Aggregator Managed Portfolio Program—which combine for nearly 300 MW of potential load drop with 3,000 customers enrolled. Finally, PG&E has two dynamic pricing programs, one for its commercial customers known as Peak Day Pricing and one for its residential customers known as SmartRate™, which have a combined total enrollment of 125,000 customers. With the exception of its dynamic pricing programs, all DR programs are locationally dispatchable accounting for approximately 550 MW. In addition to these programs, PG&E is also conducting a range of pilots, which are explained below in Section II.B.2.c.

PG&E's 2012-2014 DR programs were approved by the Commission on April 19, 2012 in D.12-04-045. PG&E's adopted 2012-2014 DR programs also incorporate changes to allow PG&E's DR programs to bid into the CAISO market as a supply resource via the Proxy Demand Resource or Reliability Demand Response Resource product.

b. Regulatory Initiatives and 2015-2016 Bridge Funding

In 2013, the CPUC initiated the DR Rulemaking (i.e., R.13-09-011) "to enhance the role of DR in meeting the state's resource planning needs and operational requirements." The Commission initiated the DR Rulemaking to determine whether and how to bifurcate current utility-administered, customer-funded DR programs into demand-side and supply-side resources in order to prioritize DR as a utility-procured resource, competitively bid into the CAISO wholesale electricity market. The DR Rulemaking outlined the purposes of the proceeding as follows: (1) review and analyze current DR programs to determine whether and how they could be bifurcated into demand-side and supply-side resources; (2) create an appropriate competitive procurement mechanism for supply-side DR resources; (3) determine program approval and funding cycles; (4) provide guidance for transition years; and (5) develop and adopt a roadmap for collaboration and coordination with other Commission proceedings and state activities related to DR.

Decision 14-05-025 approved Bridge Funding for DR programs from 2015 through 2016 to bridge the period until substantial changes from the DR Rulemaking can be implemented beginning in 2017. While this decision primarily served to extend the budget for existing programs, it also approved minor program improvements proposed by the IOUs. PG&E's proposals included the continuation of the T&D Deferral Pilot and the Intermittent Resource Management Pilot as well as improvements for the DBP.

c. New Demand Response Programs and Pilots

In addition to PG&E's existing DR programs, which include a variety of programs for commercial and residential customers, PG&E is working on a range of pilots, programs and initiatives that address changing grid needs and leverage advanced technologies. On August 4, 2014, parties filed a settlement proposal in the DR Rulemaking that would establish a framework to determine issues including the future value of DR programs, new procurement mechanisms (such as the DR Auction Mechanism), extended budget cycles. The decision for this settlement is expected to be issued in December 2014.

3. RPS-Eligible Resource Procurement

PG&E strongly supports the development of cost-effective renewable resources consistent with the EAP Loading Order. As of June 2014, PG&E had signed 161 contracts with RPS-eligible resources totaling over 10,900 MW of capacity. In addition to the contracts, PG&E has Utility-Owned Generation ("UOG") that is RPS-eligible, such as hydroelectric resources and UOG developed through PG&E's Photovoltaic ("PV") Program approved by the Commission in D.10-04-052. PG&E is continuing to procure RPS-eligible resources to achieve the 33 percent-by-2020 goal established by Senate Bill ("SB") 2 in the First Extraordinary Session (SB 2 1X).

PG&E's renewable procurement strategy is described in detail in its Draft RPS Procurement Plan ("Plan" or "RPS Plan") filed on June 4, 2014 in R.11-05-005. Although PG&E has executed contracts that represent well over 20 percent of its future energy needs, PG&E's ability to meet the RPS targets is sensitive to the timely completion of renewable energy projects, which are subject to uncertainties and risks. Chief among the uncertainties facing renewable projects under development are permitting challenges related to time-intensive and potentially high-cost transmission planning and development, and access to financing. Additionally, sustained variability in either PG&E's load or RPS generation can significantly impact PG&E's RPS compliance status. For example, the ongoing drought in California tends to reduce generation from RPS-qualifying hydroelectric facilities. PG&E's RPS Plan provides a detailed discussion regarding these risks and potential impediments.[7]

PG&E generally procures renewable RPS-eligible resources through annual solicitations conducted pursuant to its RPS Plan and bilateral negotiations. In addition, PG&E also procures renewable resources through specific, Commission-approved programs that are targeted to specific types of RPS-eligible resources. For example, in D.10-12-048, the Commission directed PG&E and the other California IOUs to conduct Request for Offers ("RFO") for renewable resources under 20 MW as a part of the Renewable Auction Mechanism ("RAM") Program. In Resolution E-4582, the Commission deferred one-third of the remaining unsubscribed capacity that would have been procured in the fourth and final RAM solicitation to a fifth RAM solicitation. In addition, PG&E filed a Petition for Modification of D.10-12-048 in 2014 to combine the remaining authorized capacity in PG&E's PV Program into the RAM Program.

PG&E also procures RPS-eligible energy through Commission-approved Feed-in Tariffs ("FIT"), which include tariffs and standard form contracts for small renewable resources that are 3 MW or less. In D.12-05-035 and D.13-05-034, the Commission approved PG&E's Electric-Renewable Market Adjusting Tariff ("ReMAT") to implement SB 32. The Commission is also implementing SB 1122, which would further increase the

[7] See PG&E's June 4, 2014 Draft 2014 Renewable Energy Procurement Plan, filed in R.11-05-005, at Section 5, pp. 34-45, and Section 6, pp. 46-57.

statewide procurement target of small renewable resources targeting small-scale new build bioenergy projects (biogas, dairy, other agricultural bioenergy, and byproducts of sustainable forest management).

Finally, PG&E procures RPS-eligible energy and capacity from renewable QFs. Many of these QF projects are providing RPS-eligible energy to PG&E under long-term contracts executed in the 1980's and 1990's.

4. Distributed Generation

PG&E has supported DG before the California Legislature, the Commission, and through a variety of internal process improvements. PG&E's customers continue to play an important role in developing DG by adding generation to the electrical grid. In addition to RPS programs which can include DG, such as the FIT Program, PG&E also administers several programs that support DG: the California Solar Initiative ("CSI"); the Self-Generation Incentive Program ("SGIP"); and several Net Energy Metering ("NEM") programs. The following sections describe PG&E's current DG strategies.

a. California Solar Initiative

PG&E is committed to retaining its role as a leader in the solar market. PG&E has supported regulation and legislation that created or extended programs providing assistance to customers who choose to install solar generation. PG&E supported the CSI established by the Commission in 2005 and supported SB 1, which codified CSI. CSI was designed to promote solar adoption and lower the cost of solar systems for consumers over a 10-year period. As one of the program administrators, PG&E has helped make solar more affordable by offering incentives for residential and commercial customers.

The customer-side solar market has shown significant progress toward market transformation since the initiation of the CSI Program. To date, the program has resulted in installations of 749 MW of solar generation by PG&E's customers. Customers installing these systems have received or will receive $870 million in incentives. Due to the popularity of the CSI, the program has been fully subscribed and PG&E is on track to meet its MW targets.

In terms of solar interconnections, PG&E is the leading solar utility in the United States and is committed to continuing and expanding that leadership role. Thousands of additional PV solar systems are interconnected to PG&E's system every year by customers seeking to address environmental concerns or to fulfill a desire for energy independence. In fact, PG&E has helped customers interconnect more solar systems than any other utility in the country (see below for a description of the NEM Program).

b. Self-Generation Incentive Program

The second incentive program available for PG&E customers who choose to install clean and renewable DG or storage to help meet customer need is the SGIP. PG&E has administered the SGIP since 2001. For the first six years of the program, incentives were available for installations up to 1 MW of solar, wind, fuel cell, and efficient combustion engines. In 2007, the solar incentives were subsumed into the CSI. Starting in 2008, the SGIP was only available for wind and fuel cells, with storage technologies added in 2010 when used in conjunction with qualifying wind or fuel cells. Passage of SB 412 in 2009 expanded the program to again include efficient CHP as well as energy storage as an eligible stand-alone technology. In addition, SB 412 implemented a performance-based incentive structure for large systems. Most recently the program was extended by including it into the state budget trailer bill presented and approved as AB 1466. As of June 2014, 799 projects have taken advantage of the SGIP to install over 211 MW of generation to help meet their energy needs, receiving $484 million in incentives.

For clean and renewable customer generation, the SGIP can improve a customer's project economics by providing a rebate to offset the capital cost involved with installation. Whether or not a customer takes advantage of the SGIP, any customer installing at-site generation will benefit from both interconnection process improvements and savings on energy bills.

c. Net Metering Programs

The NEM Program allows customers with renewable generation installations up to 1 MW to export power when their generator produces more than they need at any given time. These exports can be used to offset customer usage when their renewable power does not meet on-site needs (e.g., at night when the sun does not shine). On a monthly basis, any excess kWh exports are converted to a monetary credit using the customer's retail rate. These credits are available to offset charges over an annual "true-up" period. Historically, the legislature required that at the end of the true-up period, any excess credits be forfeited. However, in 2009, the legislature passed AB 920, which provides for payment for net excess generation over the course of the true-up period. On June 9, 2011, the Commission approved the Net Surplus Compensation ("NSC") rate for NEM customers who produce more electricity (kWh) than they use over their true-up period, usually 12 billing months.[8] The NSC rate is based on a rolling 12 month average of spot market prices. Based on current market prices, the rate would be about 4 cents per kWh. This compensation is for the energy only. The Renewable Attribute Adder payment to customers for the RPS-eligible Renewable Energy Credits ("REC") was set at 1.8 cents per kWh. The Commission determined the compensation for the REC, but left it to the CEC to set up a process to verify and track these attributes. This process is in place, and PG&E will make an additional payment for the REC value of the excess kWh to customers who opt to register with the Western Renewable Energy Generation Information System ("WREGIS") and the CEC, and who transfer their RECs to PG&E.

The Commission and legislature have also amended the NEM Program to address the needs of some specific customers groups. Low-income participants in the CSI Program can allocate the generation from their renewable installation to any customer within the same low-income house project. For non-low-income customers, any building owner can allocate generation to any accounts behind same service delivery point, and any customer can allocate generation from a renewable generator to any other account they have on their own contiguous or adjacent property.

As of July 30, 2014, over 128,000 PG&E customers had installed over 1,130 MW of renewable generation under the NEM Program.

Finally, PG&E administers Renewable Energy Self-Generation – Bill Credit Transfer, a net metering program that allows local governments, including school districts and the University of California/California State Universities to site renewable generation

[8] D.11-06-016.

at one location and export excess electricity to PG&E's grid. PG&E calculates a credit for those exports, based on the generation component of the energy rate of the customer's tariff at the point where the generator is located. This credit can be used to offset generation charges at any other account for that local government customer.

5. Other Generation Resources

In addition to the EE, DR, RPS, and DG procurement programs and resources described above, PG&E procures energy and capacity on behalf of its customers from other types of resources. This section describes the other types of resources in PG&E's portfolio that are used to meet customer needs.

First, PG&E procures electric products from non-RPS-eligible CHP and QF resources. Some of the CHP/QF procurement is under pre-existing legacy contracts, while other procurement is based on contracts approved as a part of the QF/CHP Settlement. The QF/CHP Settlement was approved by the Commission in D.10-12-035 and became effective on November 23, 2011. Since the QF/CHP Settlement became effective, PG&E has issued new standard offer contracts and conducted three RFOs for additional CHP generation, in addition to amending certain existing QF PPAs. New contracts included as a part of the QF/CHP Settlement include the Transition PPA (for QFs over 20 MW that will expire prior to July 1, 2015), an Optional As-Available PPA, and a QF Public Utility Regulatory Policies Act PPA for facilities under 20 MW. The QF/CHP Settlement also included a CHP Pro Forma PPA to be used in CHP RFOs, and allows QF/CHP resources to convert to Utility Prescheduled Facilities through a dispatchable PPA structure. In addition to procurement under the QF/CHP Settlement, PG&E is also required to offer three standard offer contracts as a result of Commission decisions issued in R.08-06-024, which implements AB 1613. These contracts are for new, eligible CHP units under 20 MW and are separate agreements from those established as a part of the QF/CHP Settlement. Two of these contracts—one for units with a capacity under 20 MW and one for units which export no more than 5 MW—have been approved and a simplified contract for units with a capacity under 500 kW has been submitted to the Commission for approval.

Second, PG&E procures electric products through short-, medium- and long-term contracts with fossil-fueled resources through the approved products in Appendix A, the approved procurement processes in Appendix B, and within the procurement limits in Appendix C.

Third, PG&E purchases hydroelectric generation through medium- and long-term agreements with Irrigation Districts and water agencies. Originating in the 1960s, the majority of the original Irrigation District contracts will expire by 2016. However, PG&E expects that the underlying resources will continue to operate beyond those expiration dates. Because of the large size of the facilities, many of these hydroelectric resources are not RPS-eligible. However, these facilities do not release GHG emissions and provide numerous environmental and reliability benefits.

Fourth, PG&E procures electric products for its customers through imports and utility-exchange agreements. The PG&E electric system is within the CAISO control area and is electrically integrated with the western states included in the Western Electric Coordinating Council electric grid. Electric power can be imported into the CAISO control area along transmission lines as far north as Canada and as far south as the Mexico/Desert Southwest regions. In PG&E's electric portfolio, imported generation may consist of existing contracts, future contracts, and potentially market purchases. In addition, PG&E's electric portfolio includes one conventional contract for generation located in the Northwest and a number of contracts for renewable generation located both in the Northwest and Southwest. The Puget Sound Energy ("PSE") Exchange contract imports from the Northwest. The PSE agreement is an exchange of 413 gigawatt-hours on a calendar year energy basis between PSE and PG&E. PG&E can take up to 300 MW hourly between June-September and in return PSE can take up 300 MW hourly between January-February and November-December. This contract is an evergreen contract with a 5-year termination notice.

Fifth, pursuant to D.13-10-040, PG&E will soon be procuring electric products from energy storage facilities. These facilities may be owned by third parties or by PG&E. PG&E's energy storage procurement strategy is described in its 2014-2015 Energy Storage Procurement Plan ("Energy Storage Plan") filed on February 28, 2014 in Application 14-02-007.

Finally, PG&E owns and operates a number of non-RPS-eligible generating facilities. These facilities including large hydroelectric facilities that are not RPS-eligible, the Helms Pumped Storage facility, fuel cells, clean and efficient conventional generating facilities (i.e., the Humboldt, Colusa, and Gateway Generating Stations), and GHG-free nuclear power (i.e., DCPP). This UOG provides considerable benefits to PG&E's customers because it is safe, reliable, affordable and environmentally beneficial.

III. Compliance With the Commission's Procurement Standards of Conduct

In D.02-10-062, the Commission adopted seven SOCs for utility procurement.[9] These standards have subsequently been modified, and two of them have been eliminated.[10] PG&E's BPP is in full compliance with Commission's SOCs. The following table includes each SOC, a summary of PG&E's compliance with the standard, and the portion of the BPP that addresses PG&E's compliance if applicable.

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9 D.02-10-062 at pp. 51-52.

10 See D.02-12-074, Ordering Paragraph ("OP") 24 (modifying standards); D.03-06-067, OP 3 (modifying standards and eliminating Standard Nos. 6-7); and D.03-06-076, OP 6 (clarifying that "Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges."). PG&E also received a waiver from SOC 1 for certain gas transportation transactions in D.04-06-003.

TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT

Standard of Conduct	Summary of Compliance and Citation to PG&E's BPP if Applicable
1. Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited.	PG&E's procurement processes and methods, including competitive, arms-length solicitations, are described in Appendix B. To the extent PG&E conducts any affiliate transactions, these transactions will be conducted in full compliance with the Commission's affiliate and procurement rules.
2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process that: (1) identifies trade secrets and other confidential information; (2) specifies procedures for ensuring that such information retains its trade secret and/or confidential status (e.g., limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.); (3) discusses employee actions that may inadvertently waive or jeopardize trade secret and other privileges; (4) discusses employee or former employee activities that may involve misappropriation of trade secrets or other confidential information, unlawful solicitation of former clients or customers of the utility, or otherwise constitute unlawful conduct; and (5) requires or encourages negotiation of covenants not to compete to the extent such covenants are lawful under the circumstances (e.g., where a business acquires business interests of individuals who subsequently work for the acquiring business, the individuals disposing of their business interests may enter covenants not to compete with their new employer). All employees with knowledge of its procurement strategies should be required to sign and abide by an agreement to comply with the comprehensive code of conduct and to refrain from disclosing, misappropriating, or utilizing the utility's trade secrets and other confidential information during or subsequent to their employment by the utility.	PG&E ensures that its Energy Procurement organization employees are in compliance with SOC 2, as described in this Section III, and provides information to demonstrate compliance to the Commission's Water and Audit Division ("Audit Division") as a part of the Quarterly Compliance Report ("QCR") process, described below in Section IV.

TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE WITH THE COMMISSION'S PROCUREMENT STANDARDS OF CONDUCT
(CONTINUED)

Standard of Conduct	Summary of Compliance And Citation To PG&E's BPP if Applicable
3. In filing transactions for approval, the utilities shall make no misrepresentation or omission of material facts of which they are, or should be aware.	PG&E has filed procurement information in a number of different reports, which are described in more detail in Section IV, below. PG&E has not misrepresented any information, or made any omission of material fact in any of these reports.
4. The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. Our definitions of prudent contract administration and LCD are the same as our existing standard. Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. LCD refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. The utility bears the burden of proving compliance with the standard set forth in its plan.	PG&E's scheduling and bidding practices are described in Appendix K. PG&E's contract administration and its demonstration of LCD are reviewed by the Commission annually as a part of the annual Energy Resource Recovery Account ("ERRA") proceedings described below in Section IV.
5. The utilities shall not engage in fraud, abuse, negligence, or gross incompetence in negotiating procurement transactions or administering contracts and generation resources.	PG&E procurement practices have been fair, open and transparent. PG&E has used an Independent Evaluator ("IE") for long-term transactions and discussed short-, medium- and long-term transactions with the Procurement Review Group ("PRG"). PG&E's procurement processes and methods are described in detail in Appendix B and the involvement of the PRG and IE are described in Appendix M. PG&E has also appropriately administered its procurement contracts. PG&E's ongoing administration is reviewed through the ERRA process and quarterly audits described in Section IV.

With regard to SOC 2, each employee of PG&E engaged with procurement activities is required to certify that he/she is aware of PG&E's Employee Code of

Conduct. A certification is electronically signed by each employee. In addition, PG&E employees are required to complete a Compliance and Ethics training course on an annual basis.

IV. Description of PG&E Filings Made to Demonstrate Compliance and Cost Recovery

A. Monthly, Quarterly and Annual Filings and Reports

PG&E submits monthly, quarterly, and annual filings to demonstrate compliance with the BPP and/or in compliance with Commission requirements regarding procurement. These filings include:

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
MONTHLY, QUARTERLY, AND ANNUAL COMPLIANCE FILINGS

Line No.	Filing Requirement	Commission Authority
1	**Monthly Portfolio Risk Reduction Report** – PG&E reports TeVaR on a monthly basis to both the Energy Division and Office of Ratepayer Advocates. TeVaR is reported on both a 95 percent and 99 percent Confidence Interval for the following periods: • Monthly for the rolling 12 month period (e.g., October 2014-October 2015) • Quarterly for the balance of the current calendar year (e.g., 2014) • Quarterly for the next three calendar years (e.g., 2014, 2015 and 2016) • Yearly for the last calendar year of reporting (e.g., 2013)	D.07-12-052

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
MONTHLY, QUARTERLY, AND ANNUAL COMPLIANCE FILINGS
(CONTINUED)

Line No.	Filing Requirement	Commission Authority
2	**Monthly ERRA Report** – PG&E files this report "showing the activity in the ERRA balancing account with copies of original source document supporting each entry over $100.00 recorded in the account" no later than the 20th following the end of the month and be served on interested parties in the proceeding. The stated intention of this report was to give the Commission an opportunity to anticipate when an IOU might file an expedited trigger application and to reduce the time to review such an application.	D.02-12-074, D.07-04-020
3	**Monthly Standing Data Request from Energy Division** – PG&E responds on a monthly basis to the Energy Division data request for electric generation procurement information. The requested procurement information relates to weekly and monthly weighted average cost of electric procurement, monthly energy and maximum capacity load forecasts for a rolling 12-month period, monthly residual net short forecast for a rolling 12-month period, and monthly electricity and gas price forecasts used to derive the residual net short forecast.	Energy Division request
4	**Quarterly Compliance Report** – The purpose of this report is to describe all electric generation procurement transactions executed in a given quarter that are not more than five years in duration, not filed through a separate advice filing or application, and within the procurement authority authorized by the Commission. The QCR includes: executed electric and fuels transactions less than five years in delivery length; strategies implemented in a given quarter, retained investments completed in the quarter; models; transactions and documentation which qualifies under the definition of reasonable showing, briefing to the senior management, related PRG materials; and counterparty information. QCRs are to be reviewed by the Commission within 60 days. If the Commission receives no protests and Energy Division staff concludes that the transactions included in this report are in compliance with the IOU's approved procurement plan, the Energy Division Director can approve the reports. The Audit Division reviews each QCR, and may propound discovery regarding specific QCR items. After its review and any discovery, the Audit Division issues an audit report. The IOUs have the opportunity to respond to any finding before the report is made final and before the final approval of the filing is made by the Director of the Energy Division.	D.02-10-062, D.03-12-062, D.04-01-050, D.04-07-028, D.04-12-048, D.07-12-052, D.12-01-033, and D.12-04-046.

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
MONTHLY, QUARTERLY, AND ANNUAL COMPLIANCE FILINGS
(CONTINUED)

Line No.	Filing Requirement	Commission Authority
5	**Annual ERRA forecast application and Annual ERRA compliance application** – The Commission established the ERRA balancing account for all three IOUs and established an update process whereby the IOUs would once a year: (1) "file applications proposing to establish annual fuel and purchased power forecasts and true up 2002 fuel and purchased costs" (i.e., ERRA Forecast Revenue Requirement proceeding); and (2) undergo a "review of balancing accounts, contract administration, utility retained generation expenses and least-cost dispatch" (i.e., ERRA Compliance Review proceeding).	D.02-10-062, D.02-12-074, D.04-01-050
6	**Annual RPS Compliance Report** – This report addresses PG&E's compliance with California's RPS requirements.	D.12-06-038
7	**RPS RFO Shortlist** – As part of PG&E's Annual RPS Plan, it is required to file a Tier 2 advice letter that includes the evaluation criteria and selection process for an RPS RFO shortlist and the related IE report.	D.13-11-024
8	**Semi-Annual RPS Project Development Status Report** – This report provides an update on the commercial and regulatory developments of PG&E's contracted renewable resources.	D.06-05-039
9	**Annual RPS Plan** – PG&E's annual RPS plan.	Pub. Util. Code § 399.13(a)(1)
10	**Annual RPS Transmission Report** – Annual report to the CPUC identifying any electrical transmission facility, upgrade, or enhancement that is reasonably necessary to achieve the RPS targets.	Pub. Util. Code § 399.13(a)(2)
11	**Annual RAM Program Compliance Report** – This report concerns PG&E's administration of the RAM program.	D.10-12-048
12	**Annual PV Program Compliance Report** – This compliance report describes PG&E's PV RFO process.	D.10-04-052, Resolution E-4368
13	**Quarterly Convergence Bidding Report** – This report describes PG&E's convergence bidding activities for the preceding quarter and is included with the QCR.	D.10-12-034
14	**Annual RA Report** – This report demonstrates compliance with PG&E's Year-Ahead System RA, Local RA, and Flexible RA obligations and follows the guidance from the Commission Staff's annual filing guide.	D.04-01-050, D.04-10-035, D.05-10-042, D.06-06-024, D.06-07-031, D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036, D.11-06-022, D.12-06-025, D.13-06-024, and D.14-06-050

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
MONTHLY, QUARTERLY, AND ANNUAL COMPLIANCE FILINGS
(CONTINUED)

Line No.	Filing Requirement	Commission Authority
15	**RA Year-Ahead Load Migration Report** – This report provides year-ahead load forecast adjustments to reflect anticipated load migrations. This report is submitted in spring of the prior year with any necessary adjustments made in the summer of the prior year.	D.05-10-042 and D.11-06-022
16	**Monthly RA Compliance Report** – This report provides a monthly forecast and demonstrates that PG&E has acquired sufficient resources to satisfy its commitment obligation for load plus reserves.	D.04-01-050, D.04-10-035, D.05-10-042, D.06-06-024, D.06-07-031, D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036, D.11-06-022, D.12-06-025, D.13-06-024, and D.14-06-050
17	**Monthly RA Month-Ahead Load Migration Report** – This report provides load forecast adjustments to reflect anticipated load migrations.	D.05-10-042 and D.10-12-038
18	**Semi-Annual QF Cogen and Small Power Producers Report** – This report provides a list of all operational QF Cogen and SPP facilities that are delivering energy to PG&E under a QF contract.	Resolution E-1738, D.82-01-103, D.82-12-120, D.90-03-060, D.91-10-039, D.93-04-001, D.96-12-028, D.97-05-021 and D.02-10-009.
19	**Semi-Annual CHP Program Report** – This report provides progress toward both MW and GHG targets pursuant to the QF/CHP Settlement.	D.10-12-035
20	**Energy Storage Plan** – PG&E's biennial procurement plan for energy storage resources.	D.13-10-040

Some of these reports may no longer be required if and/or when certain programs terminate or are modified by the Commission. In addition to these reports, PG&E also provides the Commission with information in response to standing data requests, as well as one-time data requests issued for a specific purpose.

B. Additional Reporting Requirements – ERRA Trigger

In AB 57, the California state Legislature established a trigger mechanism that would ensure that any overcollection or undercollection in the appropriate electric procurement balancing account does not exceed 5 percent of a utility's recorded generation revenues, excluding California Department of Water Resources ("CDWR") revenues, for the prior year.[11] This trigger mechanism provides the necessary assurance to PG&E that its electric procurement costs will be recovered in a timely fashion. In D.02-10-062, the Commission adopted the AB 57 balancing account trigger mechanism for the IOUs. In that decision, the Commission directed the utilities to file an expedited "trigger" application for approval within 60 days of filing when the ERRA balance reaches or exceeds 4 percent of the prior year recorded generation revenues excluding CDWR revenues. This application is to include a projected account balance in 60 days or more to illustrate when the balance will reach the 5 percent threshold. The application is also to adopt an amortization period of not less than 90 days to ensure timely recovery of the projected ERRA balance.[12] In D.04-01-050, the Commission adopted April 1 as the date when all three California utilities are to file their annual ERRA trigger advice letter, which sets the trigger amount for the following 12 months.

In D.04-12-048, the Commission committed to keep the ERRA trigger mechanism "in effect during the term of the long-term contracts, or ten years, whichever is longer."[13] Because the long-term contracts that were entered into as a result of D.04-12-048 have not yet expired, the ERRA trigger mechanism remains in place.

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[11] Pub. Util. Code § 454.5(d)(3).

[12] D.02-10-062 at pp. 63-65, Conclusion of Law 15, and OP 14.

[13] D.04-12-048, Finding of Fact 70.

C. Description of Cost Recovery for Bundled Procurement Plan Procurement

PG&E's ERRA is to record and recover power costs, excluding CDWR contract costs, associated with PG&E's authorized procurement plan, pursuant to D.02-10-062, D.02-12-074 and Pub. Util. Code § 454.5(d)(3), and any succeeding decision, which approves PG&E's procurement activities. Costs recorded in ERRA include, but are not limited to, procurement costs associated with third-party contracts, UOG fuels, CAISO market purchases and charges, GHG procurement costs, hedging and collateral costs, revenues or costs related to CRRs and convergence bidding, costs related to IE, and fees associated with participating in the WREGIS. These costs are offset by revenues received from the CAISO markets, sales to third parties, and other market transactions related to procurement. The specific costs, expenses, and revenues recovered in ERRA are identified in Electric Preliminary Statement CP – ERRA.

V. Pre-Approval, Approval, and Filing Requirements

PG&E may execute contracts that are consistent with the BPP with a contract duration of less than five years without Commission pre-approval. Specifically, PG&E can enter into contracts with delivery terms of less than five years, provided the delivery term ends within the 10-calendar-year Long-Term Procurement Plan procurement cycle (e.g., for the 2014 BPP, contracts utilizing this rule may not include deliveries beyond December 31, 2024).[14] The length of the contract duration includes any extension options provided for in the contract. For contracts with a duration of five years or greater, PG&E will file an application for pre-approval of the contract. The only exceptions to

[14] See D.07-12-052 at p. 172 and OP 19.

this requirement are for: (1) RPS contracts which are filed by a Tier 3 advice letter pursuant to D.04-07-029; (2) PG&E is not required to file an application with the Commission for approval of the acquisition of Long-Term Congestion Revenue Rights ("LT-CRRs") with a duration of more than five years;[15] (3) nuclear fuel contracts pursuant to the Nuclear Fuel Procurement Plan (Appendix F); (4) specific form contracts that are pre-approved by the Commission such as contracts under the QF/CHP Settlement and the ReMAT Program; and (5) gas supply, pipeline capacity, and storage transactions with duration from 5-10 years in duration may be filed for approval via a Tier 3 advice letter.[16] In addition, the Commission may issue decisions providing that other specific types of contracts or transactions that are five years or greater in duration do not require an application for pre-approval.

With regard to filing requirements, the Commission has adopted the following requirements:

[15] See Resolution E-4122 at p. 10.

[16] D.12-01-033 (approving PG&E's gas supply plan, except for biomethane purchases, which included a provision that gas supply, pipeline capacity and storage transactions with duration from 5-10 years in duration may be filed via a Tier 3 advice letter).

TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
CALIFORNIA PUBLIC UTILITIES COMMISSION FILING REQUIREMENTS

Line No.	Type of Transaction	Filing Requirements[17]	Commission Authority
1	Non-RPS Transactions with a contract duration less than five years	Quarterly Compliance Report or advice letter filing	D.07-12-052
2	Non-RPS Transactions with a contract duration five years of greater, except when the Commission has determined otherwise (e.g., form contracts under the QF/CHP Settlement, AB 1613 Feed-in Tariff)	Application	D.04-12-048
3	RPS-eligible Energy Transactions (including amendments to approved RPS-eligible PPAs), except when the Commission has determined otherwise (e.g., form contracts under the ReMAT Program)	Advice Letter	D.11-05-005
4	Gas Supply, Pipeline Capacity, and Storage Transactions	Less than five years in contract duration – Quarterly Compliance Report	D.03-12-062
		Five years to ten years in contract duration – Advice Letter	D.12-01-033
5	Combined Heat and Power Contracts	Five years or longer in contract duration – Advice Letter (Tier 3 for material modification to the pro forma PPA, Tier 2 for modified pro forma PPA without material changes)	D.10-12-035
		Less than five years in contract duration – Quarterly Compliance Report	
6	Amendments to existing QF contracts	Less than five years in contract duration – Annual ERRA Compliance Report or Advice Letter	D.06-12-009
		Five years or longer in contract duration – Application	D.06-12-009, D.04-12-048
7	Nuclear Fuel Contracts pursuant to the Nuclear Fuel Procurement Plan	Annual ERRA Compliance Report	D.12-01-033
8	LT-CRRs and CRR	Quarterly Compliance Reports	Resolutions E-4135 and E-4122

[17] Advice letters are Tier 3 advice letters unless otherwise noted.

TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
CALIFORNIA PUBLIC UTILITIES COMMISSION FILING REQUIREMENTS
(CONTINUED)

Line No.	Type of Transaction	Filing Requirements	Commission Authority
9	Non-RPS-eligible UOG	Advice Letter filing demonstrating RFO failure. After the Commission issues a resolution determining that an RFO has failed, PG&E may file an application for a proposed new Non-RPS eligible UOG resource.	D.12-04-046
10	RPS-eligible UOG	Application	D.11-05-005
11	Contracts with Once Through Cooling resources	Contracts that are two years or less in duration and terminated more than a year before the State Water Resources Control Board ("SWRCB") compliance deadline in the Quarterly Compliance Report. Contracts that are more than two years but less than five years in duration or terminate a year or less before the SWRCB compliance deadline in an advice letter. Contracts that are five years or more in duration by Application. Contracts with duration beyond the SWRCB compliance deadline either by an advice letter (for contracts that are less than five years in duration) or application (for contracts that are five years or more in duration).	D.12-04-046
12	Greenhouse Gas Products	Transactions for GHG Products with vintage years four years or fewer into the future, Quarterly Compliance Report. Transactions for GHG Products with vintage years more than four years into the future, PG&E will submit the transactions for review through the Commission's advice letter process.	D.12-04-046, approving PG&E's 2010 GHG Plan

VI. Updates to the Bundled Procurement Plan Via Advice Letter

Updates and modifications to the BPP proposed before the next BPP application, including a request for an extension of procurement authority, will be made via a Tier 3 advice letter.

In addition to the general authority to propose updates and modifications to the BPP through a Tier 3 advice letter, the Commission has approved a specific mechanism for seeking approval of modifications to PG&E's Hedging Plan. Should market conditions or the electric portfolio change to the point of necessitating modifications to the Hedging Plan, PG&E will submit an advice letter to the Commission requesting changes using a process similar to the advice letter process approved in Resolution E-3951. In that resolution, the Commission stated:

> While PG&E's plan provides for some degree of flexibility and specifies that it will consult with its PRG during its execution, the utility may find that modifications to the plan should be undertaken. Accordingly, PG&E is authorized to file minor modifications to the hedging plan approved in this resolution through an advice letter filing. We delegate authority for the review and, if appropriate, approval of any such advice letters to the Energy Division.[fn. 9] Prior to filing any such advice letters, the utility shall present its proposals to its PRG in an effort to mutually resolve any PRG concerns.[fn. 10]
>
> Fn. 9 The Energy Division may reject the advice letter if PG&E seeks modifications that the Energy Division considers are not minor or on other procedural grounds.
>
> Fn. 10At minimum, a Hedging Plan modification advice letter should include a detailed description of the proposed changes, supporting analysis, quantification of the proposal's costs and benefits and demonstrate how the proposal is consistent with the Commission's directives and PG&E's Commission-approved procurement plans.[18]

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[18] Resolution E-3951, p. 6.

PG&E will also file an annual (or more frequent, if necessary) updates to its electrical capacity, electrical energy and natural gas procurement limits and ratable rates included in Appendix C in a Tier 1 advice letter.[19] This update will provide PG&E with the opportunity to adjust its procurement limits and ratable rates to reflect changes in PG&E's portfolio and updated forecast assumptions.

Finally, PG&E will update its GHG compliance forecasts and corresponding purchase limits included in Appendix C as necessary via a Tier 2 advice letter.[20] The advice letter will include a description and workpapers detailing the calculation of the estimated purchase limits and an explanation of the key drivers of differences from the prior estimates.

[19] The updated limits calculations shall be consistent with the methodology employed in Appendix C.

[20] D.12-04-046, OP 9.

APPENDIX A

PROCUREMENT PRODUCTS

A. Electric Products

Pacific Gas and Electric Company ("PG&E") uses a variety of physical and financial electric products to meet its electric procurement needs. Table A-1 below provides product names, descriptions and citations to the initial regulatory authority approving procurement of these products.

TABLE A-1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PRODUCTS

Line No.	Product	Description	Initial Authorization
1	Ancillary Services ("A/S")	Products that are utilized by the control area operator to ensure electric system reliability for example, those that are listed in control area operator tariffs, such as the California Independent System Operator ("CAISO").	D.02-10-062
2	Capacity (Demand Side)	The amount of power consumed by a customer, measured in megawatts ("MW"), that can be reduced upon request.	D.02-10-062
3	Capacity (Purchase or Sale)	The amount of power capable of being generated, measured in MW, that can be converted to energy upon request.	D.02-10-062
4	Contingent Forward	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
5	Electric Product Exchange	The buyer has an obligation to receive electric products and an obligation to return electric products as part of the same transaction. The transaction may also include an exchange of payments, in fixed or variable terms. Electric products include energy, capacity, and A/S.	AL 2615-E
6	Electricity Transmission Products	Purchase, sale, or allocation of transmission rights, products (e.g., Long-Term Firm Transmission Rights, Congestion Revenue Rights ("CRR"), losses), or the use of locational spreads for CAISO and non-CAISO transmission.	D.02-10-062 D.07-12-052 D.12-01-033

Line No.	Product	Description	Initial Authorization
7	Financial Call (or Put) Option or Swaption	An Option is the right, but not the obligation, to buy or sell a forward electric contract on a specific date (expiration) at a fixed or indexed price (strike). The right to buy is a call option, and the right to sell is a put option. Additional examples include locational spread options, time spread options, cross-commodity options, and exotic (combination) options. A Swaption is an option on a Financial Swap or Futures contract.	D.02-10-062 AL 3482-E
8	Financial Swap	An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps, locational spread (basis) swaps, time spread swaps, cross-commodity swaps and payment obligation swaps (e.g., CAISO Integrated Forward Market ("IFM") Uplift Load Obligations). Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.	D.02-10-062 AL 2615-E D.07-12-052 AL 3482-E
9	Forward Energy (Demand-Side)	Electric energy planned to be consumed by a customer, measured in megawatt-hour ("MWh") that is agreed to be reduced for a specific period for a specified time in the future.	D.02-10-062
10	Proxy Demand Response ("PDR"), Reliability Demand Response Resource ("RDRR"), and Participating Load ("PL")	*PDR:* Virtual generator that is paid for response to dispatches and market awards with performance based on a baseline method. *RDRR:* Virtual generator that is paid for response to dispatch in near emergency conditions with performance based on a baseline method. *PL:* Load acting as a resource with individual scheduling of load and generation for the PL.	D.10-06-002 D.10-12-036 AL 3635-E-A AL 3689-E-A
11	Forward Energy (Purchase or Sale)	Electric energy purchased or sold by a counterparty, measured in MWh that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.	D.02-10-062
12	Forward Spot (Day-Ahead and Hour-Ahead) Purchase, Sale, or Exchange	Electric energy, capacity, A/S or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MW or MWh that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.	D.02-10-062
13	Electricity Futures (Purchase or Sale)	Standardized forward energy contract traded on an exchange. Examples include fixed-for-floating futures, locational spread (basis) futures, time spread futures, cross-commodity futures and payment obligation futures.	AL 2615-E

Line No.	Product	Description	Initial Authorization
14	On-Site Energy or Capacity (Self-Generation on Customer Side of the Meter)	The amount of power measured in MW or MWh that can be generated downstream of the customer's electric meter that can be used to offset the customer's load served by the electric service provider.	D.02-10-062
15	Peak for Off-Peak Exchange	Electric energy, capacity, or A/S or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period. These transactions may also include an exchange of dollars.	D.02-10-062
16	Physical Call (or Put) Option	The right, but not the obligation, to buy or sell physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to buy is a call option, and the right to sell is a put option.	D.02-10-062
17	Real-Time (Purchase or Sale)	The amount of energy, measured in MWh supplied or received by the control area operator to balance an entity's load and supply.	D.02-10-062
18	Resource Adequacy ("RA") Product	A capacity product intended to meet RA obligations.	AL 2615-E AL 2897-E
19	Seasonal Exchange	Electric energy, capacity, or A/S or transmission exchanged between counterparties measured in MW or MWh that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. These transactions may also include an exchange of dollars.	D.02-10-062
20	Tolling Agreement	An agreement to provide (receive) gas in exchange for receiving (providing) electricity.	D.02-10-062 D.04-12-048
21	Emissions Credits Futures or Forwards	Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.	D.03-12-062
22	Forecast Insurance	A method for managing load forecast (volume and shape) risk.	D.03-12-062
23	Firm Transmission Rights ("FTR") Locational Swaps	Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.	D.03-12-062
24	Non-FTR Locational Swaps and Futures	Locational basis swaps or futures. Swaps are financially settled directly with a counterparty or may be cleared through a financial clearinghouse. Futures are traded on an exchange.	D.03-12-062
25	Weather Triggered Options	A method for managing temperature and other weather forecast risks.	D.03-12-062

Line No.	Product	Description	Initial Authorization
26	Resource Adequacy Import Capacity Counting Right	The right to count import energy or import RA product at an intertie toward satisfying RA requirements.	AL 2897-E
27	Long-Term Congestion Revenue Rights	Financial instruments to hedge Locational Marginal Price ("LMP") congestion in Market Redesign and Technology Upgrade ("MRTU") for 10 years.	AL 3095-E
28	Congestion Revenue Rights	Financial instruments to hedge LMP congestion in MRTU, including, for example, monthly CRRs and seasonal CRRs.	D.02-10-062 D.07-12-052 AL 3106-E
29	Path 26 Resource Adequacy Capacity Counting Rights	The right to count south of Path 26 RA product toward satisfying RA requirements.	D.07-06-029
30	Convergence Bids	Virtual supply or virtual demand bids submitted in the CAISO day-ahead IFMs that, if cleared, would automatically liquidate with an opposite buy or sell in the CAISO Fifteen-Minute Market.	D.10-12-034 D.11-06-004
31	Tradable Renewable Energy Credits ("TREC")	TREC that can be used for compliance with California's Renewables Portfolio Standard Program.	D.10-03-021 D.11-01-025
32	QF Fixed for Short-Run Avoided Cost ("SRAC") Floating Swap (purchase)	A fixed-for-floating SRAC swap settled directly with the QF counterparty.	D.12-01-033
33	Structured Transaction	Combine one or more product types, varying expiration dates, tiered prices, etc.	D.07-12-052

B. Greenhouse Gas Products

PG&E uses a variety of products to meet its greenhouse gas ("GHG") compliance obligations. Table A-2 below provides product names, descriptions and citations to the initial regulatory authority approving procurement of these products.

TABLE APPENDIX A-2
PACIFIC GAS AND ELECTRIC COMPANY
GHG PRODUCTS

Line No.	Product	Description	Initial Authorization
1	GHG Allowance	A compliance instrument accepted by California Air Resources Board ("CARB") providing the right to emit one metric tons of carbon dioxide equivalent to satisfy obligations under the Cap-and-Trade regulation.	D.12-04-046

Line No.	Product	Description	Initial Authorization
2	GHG Offset Credit ("Offset")	A compliance instrument representing a verified emission reduction that is accepted by CARB in lieu of a GHG Allowance to satisfy obligations under the Cap-and-Trade regulation.	D.12-04-046

C. Fuel Products

PG&E uses a variety of physical and financial gas products to support electric procurement and reliability. In addition, PG&E uses a small amount of distillate fuel for its Humboldt Bay Generating Station. Table A-3 below provides physical gas product names, descriptions and information about the initial regulatory authority approving procurement of these products, as well as distillate fuel.

TABLE A-3
PACIFIC GAS AND ELECTRIC COMPANY
FUEL PHYSICAL PRODUCTS

Line No.	Product	Description	Initial Authorization
1	Natural Gas (Physical Supply)	Purchases/sales/exchanges of physical natural gas for terms including one day ("spot") or longer. Physical supply includes natural gas liquids comingled with flowing gas supplies.	D.02-10-062
2	Physical Options on Natural Gas Supply (Purchase or Sale)	The right, but not the obligation, to buy (call option) or sell (put option) physical gas for delivery on a particular date or dates at a fixed or index price (strike).	D.02-10-062
3	Biomethane (Purchase or Sale)	Pipeline quality natural gas produced from renewable (non-fossil based) resources.	D.07-12-052
4	Contingent Forward (Purchase or Sale)	A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.	AL 2615-E
5	Gas Storage (Purchase or Sale)	Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.	D.02-10-062
6	Gas Transportation (Purchase or Sale)	Interstate, intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.	D.02-10-062

Line No.	Product	Description	Initial Authorization
7	Distillate (Physical Supply)	Purchase or sale of distillate for use as backup and/or startup fuel (*i.e.*, Humboldt Bay).	D.06-11-048, OP 17

Financial products are used to support gas hedging. Table A-4 below provides financial gas product names, descriptions and information about the initial regulatory authority approving procurement of these products.

TABLE A-4
PACIFIC GAS AND ELECTRIC COMPANY
FUEL FINANCIAL PRODUCTS

Line No.	Product	Description	Initial Authorization
1	Natural Gas Financial Swaps (Purchase or Sale)	Gas derivative contracts wherein each party agrees to exchange one set of cash flows for another, including fixed-for-floating swaps, locational spread (basis) swaps, time spread swaps, cross-commodity swaps and swing-swaps (fixed-price or monthly index for daily index). Swaps are financially settled directly with a counterparty or a financial clearinghouse.	AL 2615-E D.02-10-062 AL 3482-E
2	Natural Gas Futures (Purchase or Sale)	Standardized forward contracts for gas products that trade on an exchange. Examples include futures contracts, locational spread (basis) futures, time spread futures, cross-commodity futures and swing/index futures (fixed-price or monthly index for daily index).	AL 2615-E
3	Financial Options (Call or Put) or Swaptions (Purchase or Sale)	The right, but not the obligation, to buy (call) or sell (put) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). Over-The-Counter-traded options settle financially, whereas exchange traded (NYMEX) options are exercised, which causes delivery of a futures position to the option holder. Additional examples include locational spread options, time spread options, cross-commodity options, and exotic (combination) options. A Swaption is an option on a Financial Swap or Futures contract.	D.02-10-062 AL 3482-E

D. Credit Products

Credit products are used to support electric and gas hedging and procurement. Table A-5 below provides credit product names, descriptions and information about the initial regulatory authority approving procurement of these products.

TABLE A-5
PACIFIC GAS AND ELECTRIC COMPANY
CREDIT PRODUCTS

Line No.	Product	Description	Initial Authorization
1	Counterparty Credit Insurance	A method for managing payment or performance risk for a fee.	D.02-10-062 AL 3482-E
2	Counterparty Sleeves	Facilitating a transaction with an un-contracted or non-creditworthy counterparty through a contracted, creditworthy counterparty. Applies to physical and financial electric and gas products.	D.02-10-062 D.03-12-062 AL 3482-E
3	Credit Intermediation Arrangement	Eliminates the need to post collateral on specific, identified, existing hedge positions. Under this arrangement, PG&E would novate existing positions from one counterparty to another creditworthy counterparty that does not require PG&E to post collateral in exchange for a negotiated fee. The new counterparty may or may not post collateral to PG&E, depending on the arrangement.	AL 3482-E

APPENDIX B

PROCUREMENT PROCESSES AND METHODS

A. Introduction

This Appendix addresses Pacific Gas and Electric Company's ("PG&E") procurement processes and methods. In Section B, PG&E provides a narrative description of various procurement processes that it uses to provide safe, reliable, affordable and environmentally-sensitive electric service for its customers. This section also describes California Public Utilities Commission ("CPUC" or "Commission") directed or mandated procurement programs that incorporate specific procurement processes and procurement processes administered by the California Air Resources Board ("CARB"). Section C provides a table of Commission-approved processes that can be utilized by PG&E for procurement. Section D describes Commission-adopted limitations or requirements on specific processes.

B. Overview of Procurement Processes

This section provides an overview of the procurement processes available to PG&E. These processes include: (1) market processes, including California Independent System Operator ("CAISO") markets; (2) Commission mandated or directed procurement programs that incorporate specific procurement processes; and (3) Greenhouse Gas ("GHG") compliance instrument auctions and the Allowance Price Containment Reserve ("APCR") administered by CARB.

1. Market Processes

a. Exchanges

For electric, gas and GHG markets there are several types of transparent exchanges: electronic trading platforms such as the Intercontinental Exchange ("ICE"), New York Mercantile Exchange ("NYMEX") Globex, and the Natural Gas Exchange; and open outcry exchanges such as the NYMEX. A list of exchanges that PG&E is authorized to use is included in Appendix J.

Electronic trading platforms allow market participants to post bids and offers for specific products. To complete a trade, a buyer must lift an offer or a seller must hit a bid. Once completed, the exchange confirms the transactions to both parties. NYMEX hosts open outcry trading for its natural gas futures contracts and natural gas options. Buyers and sellers transmit bids and offers to the trading pits through a Futures Commission Merchant ("FCM"). The trade is executed by the trader in the trading pit. The results of the trade are communicated back to the buyer or seller through the FCM.

In these ways, exchanges allow buyers and sellers to adjust their prices openly in the marketplace, transparently and anonymously, until a trade is executed. Exchanges also ensure product standardization. This transparency and homogeneity helps ensure that transaction selection is made on product availability, credit availability, and price.

b. Voice Brokers

Voice brokers facilitate trades in the wholesale markets. Brokers communicate bids and offers to market participants through squawk boxes,[1] electronic messages such as instant messaging, and telephone calls. Brokers work with buyers and sellers to facilitate trades. Once completed, brokers confirm the transactions with both parties and may also initiate financial clearing with a clearing house such as NYMEX or the ICE.

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[1] A squawk box is an intercom speaker used for communication between brokers and traders. The box allows brokers to broadcast market information to traders and to have one-on-one conversations with traders. PG&E records all communication on its squawk boxes as part of its trading process controls.

Brokers facilitate the trading of physical and financial products. Brokers, as part of their price discovery role, provide price reporting services to subscribing clients.

Buyers communicate bids to the broker. If a seller hits the bid, the trade is completed. If a seller does not hit the bid, the buyer can ask the broker to work its bid in the market. The broker will provide the buyer feedback if its bid is not hit by a seller. The buyer can adjust its bid until it is hit by a seller. Alternatively, if the buyer likes an offer communicated by the broker, the buyer can lift that offer to complete the trade. Since brokers facilitate trades of standard products and trading is anonymous, selection is made by product availability, credit availability and price. A list of brokers that PG&E is authorized to use is included in Appendix J.

c. CAISO Markets

Since April 2009, the CAISO has managed a Day-Ahead Market ("DAM"), also known as the Integrated Forward Market ("IFM") and provided for Locational Marginal Pricing ("LMP") at thousands of "nodes," or points of injection and withdrawal of power on the transmission grid. Under the LMP framework, suppliers that bid into the DAM are paid based on a specific nodal price, while load serving entities ("LSE") are charged based on an aggregation of nodal prices in each utility's service territory, or Load Aggregation Points. The CAISO receives bids and offers from individual buyers and sellers, determines which supplies would be used to meet the needs (i.e., energy and ancillary services, while simultaneously addressing transmission congestion and transmission line losses) and sets market clearing prices for all transactions. Through its market processes, the CAISO produces LMPs for the DAM and the Real-Time Markets

("RTM"). Since May 2014, the RTM has consisted of both Fifteen-Minute (new) and Five-Minute Markets ("FMM").

The CAISO markets were expanded to include convergence bidding products starting January 31, 2011. Convergence bids are financial transactions (i.e., virtual bids for energy that will not be consumed or produced), that can only be submitted in the day-ahead market, and are recognized by the CAISO as not being physical. Convergence bids represent a financial commitment to sell (or buy) energy in the day-ahead IFM at the individual pricing node location where the convergence bid is submitted. If these bids are cleared in the DAM, they are automatically liquidated by the CAISO with an opposite buy-back by seller or sell-back by buyer of the same quantity of energy in the FMM. In Decision ("D.") 10-12-034, the Commission authorized, but did not require, PG&E to submit convergence bids specifically to manage generator performance risks, load forecast uncertainty risks, renewable resource scheduling and hedging, and also to provide defensive bids against market dynamics. Convergence bidding is described in greater detail in Appendix H.

d. Electronic Solicitations

Electronic solicitations facilitate the competitive purchase or sale of commodity products and are defined as any competitive process where products are requested from the market. PG&E may participate in or administer as either a buyer or seller an electronic solicitation that does not involve utility-owned resources. In an electronic solicitation, the buyer or seller may post a product for purchase or sale through a variety of electronic platforms. These platforms may include but are not limited to: a secure internet site, an instant message communication, email, or via a voice solicitation to participants. Participants compete in a competitive process to provide the buyer or seller with the most advantageous price. Both sealed bid and live, open outcry solicitations are considered a competitive process. Bidders are required to meet the buyer or organizer's credit qualifications in order to participate. Selection is made by product availability and price.

e. Request for Offers

PG&E can also purchase or sell products through a Request for Offers ("RFO"). Generally, an RFO is a more formal competitive procurement process with protocols specifying the requirements to participate and the evaluation and selection of bids or offers. If PG&E conducts an RFO, it defines the products for purchase or sale and then reviews bids and offers received according to the specified protocols. PG&E may also participate in RFOs or Request for Proposals ("RFP") held by generation owners, LSE, or other market participants.

f. Bilateral Negotiations

Bilateral negotiations can be used for the purchase and sale of electric and gas products. The phrase "bilateral negotiations" is generally used in the context where negotiations take place in a one-on-one setting rather than as a part of a competitive solicitation.

2. Commission Directed or Mandated Procurement Programs

a. Qualifying Facility/Combined Heat and Power Standard Program

PG&E is offering five standard form contracts as part of its implementation of the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement, which was approved by the Commission in D.10-12-035 and became effective November 23, 2011. In addition, PG&E also is required to offer three standard offer contracts as a result of Commission decisions issued in Rulemaking 08-06-024 implementing Assembly Bill ("AB") 1613. These contracts are for new, eligible CHP facilities under 20 megawatts ("MW"). Two of these contracts—one for units with a power rating under 20 MW and one for units which export no more than 5 MW—have been approved by the Commission and a simplified contract for units with a capacity under 500 kilowatts has been submitted to the Commission.

b. Renewable Auction Mechanism Program

In D.10-12-048, the Commission directed California's Investor-Owned Utilities ("IOU") to conduct RFOs for renewable resources under 20 MW as a part of the Renewable Auction Mechanism ("RAM") Program. Subsequently, in Resolution E-4582, the Commission deferred one third of the remaining unsubscribed capacity that would have been procured in the fourth and final RAM solicitation to a fifth RAM solicitation. A Petition for Modification of D.10-12-048 was filed in 2014 to combine the remaining authorized capacity in the Photovoltaic ("PV") Program into the RAM Program, assuming the above Petition for Modification of D.10-04-052 to terminate the PV Program is approved.

c. PG&E's Photovoltaic Program

Pursuant to the authority granted in D.10-04-052, PG&E previously conducted two separate RFOs to implement its PV Program: one for utility ownership bids and the second for Power Purchase Agreements ("PPA"). A Petition for Modification of D.10-04-052 was filed in 2014 to hold a final PV PPA RFO, terminate the PV Program, and then combine the remaining authorized capacity of the PV Program into the RAM Program.

d. Energy Storage Program

AB 2514 was passed in 2010, requiring the Commission to open a proceeding to determine appropriate targets, if any, for the procurement of viable and cost-effective energy storage resources. In 2011, the Commission initiated an Order Instituting Rulemaking to implement AB 2514 and subsequently facilitated a series of workshops along with public comments on energy storage issues. In October 2013, the Commission approved a final decision (D.13-10-040) setting energy storage procurement targets for CPUC-jurisdictional load serving entities and requiring the IOUs to file applications that included plans for procuring energy storage.

e. Renewable Feed-In Tariff Programs

Consistent with Public Utilities Code § 399.20, the Commission directed the IOUs to provide tariffs and standard form contracts (i.e., Feed-in Tariffs) for small renewable resources that are 3 MWs or less. In D.12-05-035 and D.13-05-034, the Commission approved PG&E's Electric-Renewable Market Adjusting Tariff to implement Senate Bill ("SB") 32. The Commission is also currently considering the implementation of SB 1122, which would further increase the statewide procurement target of small renewable resources targeting small-scale new build bioenergy projects (biogas, dairy, other agricultural bioenergy, and byproducts of sustainable forest management).

3. CARB GHG Auctions and the Allowance Price Containment Reserve

CARB's GHG allowance auctions consist of single-round bidding, with sealed bids consisting of price and quantity, and bid units of 1,000 metric tons of carbon dioxide equivalent ("mtCO_2e"). Bidders may submit multiple bids. CARB's Cap-and-Trade regulations include detailed rules regarding the auction process and settlement price, the amount of allowances to be auctioned, bid guarantees, allowance holding limits, and purchasing limits.

The APCR, which is administered by CARB, includes a specific number of allowances. There is no refill mechanism for the APCR, and use of the APCR is restricted to entities registered with the California cap-and-trade system. Allowances purchased from the APCR go into an entity's compliance account and cannot be withdrawn or traded. APCR sales are conducted on the first day six weeks after each quarterly auction. The APCR consists of three tiers with different associated prices; each tier consists of one-third of the 121.8 million mtCO_2e allowances with which the APCR is initially populated. In 2014, Tier 1 allowances will be sold to entities with a compliance obligation at \$42.38/mtCO_2e,[2] Tier 2 at \$47.68/mtCO_2e, and Tier 3 at \$52.98/mtCO_2e.

C. Approved Procurement Processes and Practices

Table B-1 below reflects the Commission-approved procurement processes and methods that PG&E is authorized to use.

[2] The APCR price for each tier will rise by 5 percent plus the Consumer Price Index each year.

TABLE B-1
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT PROCESSES AND METHODS

Item #	Transaction Process	Description	Initial Authorization
1	Competitive Solicitations	Widely distributed request for offers or proposals. Required items include among other things: Description of product requirements, term, minimum and maximum bid quantities, scheduling and delivery attributes, credit requirements, and pricing attributes.	D.02-10-062 D.04-12-048 AL 2615-E D.07-12-052
2	Direct bilateral contracting with counterparties for short-term products (e.g., three months or less)	Bilateral process for products procured with a term three months or less. IOUs demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. The demonstration may include showing competing price offers, result of market surveys, broker and online quotes, and/or other source of price information such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction.	D.02-10-062 D.04-12-048 AL 2615-E
3	Negotiated bilateral contracts for non-standard products which terms exceed three months provided that the IOUs include a product justification in quarterly compliance filings.	Process to purchase products provided they are included in quarterly compliance filings to justify the need and process in each case. Terms and conditions are benchmarked against the best available market information for similar products recently offered. Resource Adequacy ("RA") is treated as a standard product.	D.03-12-062 D.04-12-048 AL 2615-E D.14-02-040
4	Inter-Utility Exchanges	Product exchange with other regulated utilities and other load-serving entities negotiated through private negotiation crafted to best fit the resources and needs of both parties.	D.02-10-062 D.04-12-048 AL 2615-E
5	ISO Markets: Imbalance Energy, Real-Time, Day-Ahead and Convergence Bids	Spot market transactions are authorized to meet short-term needs. Convergence Bids are authorized to manage specific areas of portfolio risks and renewable scheduling limitations.	D.02-10-062 D.04-12-048 AL 2615-E D.10-12-034
6	Transparent Exchanges, such as NYMEX and Intercontinental Exchange, Voice and On-Line Brokers	Electronic trading exchanges for transparent prices.	D.02-10-062 D.03-12-062 D.04-12-048 AL 2615-E
7	Renewables Portfolio Standard ("RPS")-Eligible Utility Ownership of Generation	Utility ownership of generation can be pursued through an RFO under certain conditions (see D.07-12-052 at 198-205; D.08-11-008 at 18-20) or outside of the RFO process under certain conditions (see D.07-12-052 at 209-213; D.08-11-008 at 20-23).	D.07-12-052 D.08-11-008
8	Non-RPS-eligible Utility Ownership of Generation	Utility ownership of generation can be pursued outside of an RFO process under certain conditions (see D.07-12-052 at 209-213; D.08-11-008 at 20-23 and D.12-04-046 at pp. 28-39).	D.07-12-052 D.08-11-008 D.12-04-046

TABLE B-1
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT PROCESSES AND METHODS
(CONTINUED)

Item #	Transaction Process	Description	Initial Authorization
9	Open Access Same-Time Information Systems	Procure standard electric transmission products from transmission providers throughout the Western Electric Coordinating Council region at the Federal Energy Regulatory Commission tariffed rates and voice and on-line brokers.	D.03-12-062 D.04-12-048 AL 2615-E
10	Electronic Solicitations	IOUs are authorized to conduct purchase or sale through an electronic solicitation format for non-utility-owned resources requested from the market. Electronic Solicitations are an approved procurement method for gas storage products, including solicitations involving PG&E California Gas Transmission, subject to all other Procurement Review Group ("PRG") review and Independent Evaluator ("IE") requirements.	D.03-12-062 D.04-12-048 AL 2615-E D.12-01-033 [Requested Clarification]
11	Market RFP	IOUs can bid in open seasons or RFPs held by generator owners, LSEs and other market participants. Such requests may also be called Requests for Bids or RFOs.	D.04-01-050 AL 2615-E D.12-01-033
12	CAISO Allocations and Auctions	CAISO allocation and auctions for LT-Congestion Revenue Rights ("CRR") and CRRs and allocation of RA counting rights.	AL 3095-E AL 3106-E D.06-07-029 AL 2897-E
13	CARB Auction	Authorization to procure GHG Allowances through any CARB Auction in accordance with the Cap-and-Trade regulation.	D.12-04-046
14	Allowance Price Containment Reserve	Authorization to procure GHG Allowances through CARB's Allowance Price Containment Reserve.	D.12-04-046
15	Cashout	As a result of certain pipeline imbalances, gas pipeline users may be cashed out according to the pipeline's tariff rules. The result is a commodity transaction, with the pipeline having bought or sold gas to or from the customer. The pipeline's tariffs include the price formula or methodology, but the actual volume and price may not be known until after the transaction is complete.	[Pending Approval]
16	Bilateral transactions for the standard products gas storage and pipeline capacity	Where there are five or fewer counterparties in the relvant market, bilateral transactions for gas storage and gas pipeline transactions are authorized.	D.03-12-062

D. Commission-Adopted Limitations and Requirements for Specific Procurement Processes

1. Requirements for Once-Through Cooling Units

PG&E may procure authorized products from once-through cooling (“OTC”) facilities through the authorized processes identified in Section B above subject to the conditions approved by the Commission in D.12-04-046, which provides:

a) **Filing Requirements**: Agreements with OTC units with a contract duration of more than two years but less than five years must be submitted to the Commission for approval via a Tier 3 advice letter. In order to provide guidance to Energy Division in evaluating these agreements and the utilities in preparing and submitting these agreements, the applicable criteria shall include the following: (1) how the contract helps facilitate compliance with the State Water Resources Control Board (“SWRCB”) OTC policy, or at a minimum why it does not delay compliance; (2) the expected operation of the OTC facility under normal load (1 in 2) and high load (1 in 10) conditions, including number of starts and run time after each start; (3) the local capacity requirements net position with and without the OTC facility over the contract duration and two years beyond the contract duration; and (4) how any other available generation compare under these criteria. OTC power purchase agreements with a contract duration of five years or more must be submitted to the Commission for approval via an application, consistent with normal procurement rules.[3]

b) **Procurement Requirements**: PG&E may procure from OTC facilities beyond the applicable SWRCB OTC compliance deadline provided that the contracts: (1) allow for utility purchase or receipt of power generated by a unit using non-compliant OTC only up to the SWRCB OTC policy compliance deadline in effect on the date the contract is signed (the contract shall not allow the utility to continue to purchase or receive power generated using non-compliant OTC beyond that date even if SWRCB extends the compliance deadline); (2) protect utility ratepayers against stranded costs; (3) protect ratepayers against the risk of future unspecified cost increases resulting from increases in the cost of the generation unit compliance with the SWRCB OTC policy (for PG&E to recover such cost increases from ratepayers, it must obtain the necessary approval from the

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[3] D.12-04-046 at pp. 25-26.

Commission); (4) are consistent with a need authorization from the System Track of the Long-Term Procurement Plan ("LTPP") proceeding; and (5) are consistent with other procurement rules, including the D.12-04-046 requirement to file either a Tier 3 Advice Letter (for contracts with a duration of less than five years) or an application (for contracts with a duration of more than five years).[4]

c) PG&E will consider a resource's use of OTC in its evaluation of offers in RFOs or solicitations.[5]

2. Requirements for Utility-Owned Generation

In D.12-04-046, the Commission established procurement process requirements for certain Utility-Owned Generation ("UOG") proposals.[6] These rules provide:

a) UOG proposals cannot participate in utility RFOs.[7]

b) UOG procurement must be done through a Certificate of Public Convenience and Necessity ("CPCN") process.[8]

c) A UOG project can only be proposed through a CPCN after a competitive solicitation has failed.[9] The Commission adopted specific filing requirements demonstrating an RFO failure that must be satisfied before a utility can submit an application for a UOG project.[10]

d) A utility application for UOG can include an analysis comparing UOG and PPAs and should include specific types of information.[11]

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[4] *Id*. at p. 27.

[5] *Id*. at p. 25.

[6] The rules do not apply to UOG proposals for resources that are RPS eligible (*see* D.12-04-046 at p. 30) and for energy storage (*see* D.13-10-040 at pp. 51-52).

[7] D.12-04-046 at p. 31.

[8] *Id*.

[9] *Id*. at pp. 37-38.

[10] *Id*. at pp. 38-39.

[11] *Id*. at pp. 32, 34-36.

e) The Commission will consider all project costs when reviewing a UOG proposal and shall evaluate the UOG proposal using criteria comparable to those used to evaluate independently-owned generation.[12]

3. Long-Term RFOs

In D.07-12-052, as modified by subsequent Commission decisions, the Commission adopted specific rules and requirements concerning the conduct of RFOs for new long-term generation resources, typically called Long-Term Request for Offers ("LTRFO").[13]

a) In advance of an LTRFO, PG&E is required to meet with an IE, PRG, and Energy Division ("ED") to outline its plans and solicit feedback prior to drafting LTRFO bid documents. Draft LTRFO bid documents are to be developed under the oversight of an IE, vetted through the PRG and any differences resolved by ED staff in advance of the public issuance of the bid documents. PG&E shall present and consult with its PRG on its LTRFO protocols, bid evaluation, bids, and shortlist list. Commission approval is required for long-term transactions through an application.[14]

b) If PG&E needs new fossil resources not formally authorized in a Commission decision in a LTPP proceeding, PG&E shall make a showing through an advice letter that unusual or extreme circumstances warrant such an action.[15]

c) PG&E shall recognize the effects of debt equivalence when comparing PPAs against PPAs in their bid evaluations.[16]

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[12] *Id*. at p. 33 and Ordering Paragraph ("OP") 7.

[13] *See* D.07-12-052 at pp. 148-153. For certain types of resources and programs, the Commission has adopted more specific and sometimes different rules. For example, for the RAM Program, the Commission has adopted specific RFO rules. The same is true for other programs such RPS RFOs, energy storage RFOs, and other specific programs. This description of the requirements in D.07-12-052 does not supersede or modify Commission requirements for resource-specific RFOs such as the RAM program or RPS.

[14] *Id*. at p. 150.

[15] *Id*.

[16] *See* D.08-11-008 at pp. 14-18.

d) PG&E shall use the project application template developed by ED when developing an application for approval of winning bid projects in a LTRFO.[17]

e) PG&E shall consider the use of brownfield sites first before building new generation on Greenfield sites, subject to the parameters set forth in D.07-12-052.[18]

f) PG&E shall publicly reveal the names of winning bidders after key commercial terms have been finalized, within 30 days of filing an application, or withdraw the application until the bidder's identity and other required information can be released. The actual contract will not be revealed.[19]

In addition to these requirements, in D.14-02-040, the Commission determined that incremental capacity from existing plants or repowered plants can participate in LTRFOs for new generation, subject to the following definitions:

- Upgraded plants: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental MW and/or enhanced operating characteristics can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a plant where the main generating equipment is retained and continues to operate.

- Repowered plants: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment (such as the turbine) is changed out for new equipment.[20]

[17] D.07-12-052 at pp. 150-151.

[18] *Id*. at p. 230.

[19] *Id*. at pp. 268-269.

[20] D.14-02-040 at pp. 28-29 and OP 2.

Incremental capacity bid into an LTRFO is "evaluated based on the cost and value of the incremental capacity alone, and not some combination of the existing and incremental capacity of the unit in question."[21]

4. Loading Order Applicability to Procurement

In D.12-01-033, the Commission indicated that the loading order applies to all utility procurement processes.[22] The Commission directed that PG&E and the other utilities procure additional Energy Efficiency and Demand Response resources to the extent they are feasibly available and cost effective. This approach continues for each step down the loading order, including renewable and distributed generation. The Energy Action Plan also requires improvements to Transmission and Distribution system to support demand growth and enable the interconnection of new generation.

5. Evaluation and Selection of Resources Through RFOs

PG&E applies a consistent evaluation methodology to offers it receives in RFOs. By applying Least-Cost, Best-Fit ("LCBF") principles, PG&E obtains the most value for customers for a given set of portfolio needs. LCBF provides for resource alternatives to be selected based on their relative cost effectiveness and their ability to meet the specific needs of the portfolio. A resource's cost effectiveness is determined relative to common market benchmarks or "market value." A resource's portfolio fit can be a qualitative assessment or quantitative measure that represents how well its energy profile, location, and other offered characteristics meet the needs of the portfolio for a particular product.

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[21] D.14-02-040 at p. 33.

[22] D.12-01-033 at pp. 20-22 and OP 4. The loading order does not apply to PG&E's scheduling and bidding of resources into the CAISO markets, which is done pursuant to least-cost dispatch principles.

6. Determining the Term of a Contract

In D.14-02-040, the Commission clarified that "[f]or the purpose of medium term and long term contracts, multiple contracts entered into at the same time for the same resource and for consecutive time periods are considered one contract and may not be treated as different transactions for Commission approval. More specifically, for the purpose of determining the "term" of a contract, two or more contracts, including contractual options, are treated as one (linked), where:

a) They specify the same resource as the primary delivery source or, (2) for an unspecified source, they are with the same counter-party; ***and***

b) They are negotiated or executed within any three consecutive month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final)."[23]

[23] D.14-02-040 at p. 40.

APPENDIX C

PROCUREMENT LIMITS AND RATABLE RATES

A. Limits

1. Electrical Capacity Procurement Limits and Ratable Rates

In Decision ("D.") 12-01-033, the California Public Utilities Commission ("CPUC" or "Commission") directed Pacific Gas and Electric Company ("PG&E") to include electrical capacity procurement limits and ratable rates in PG&E's Bundled Procurement Plan ("BPP").[1] PG&E's BPP includes the following requirements for procurement limits and ratable rates for electrical capacity:

a) The procurement limits and ratable rates apply to electrical capacity transactions with deliveries beyond the prompt calendar year (e.g., for electrical capacity transactions occurring in 2015, procurement limits and ratable rate shall apply to contract deliveries in 2017 and beyond).[2] The procurement limits and ratable rates reflect a limit on net capacity procurement, which is purchases less sales of capacity in a given year.

b) No limits or ratable rates apply to PG&E meeting its Resource Adequacy ("RA") capacity requirements for the current calendar year and prompt calendar year (i.e., the calendar delivery year immediately following the current year).

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[1] D.12-01-033 at pp. 14-15 and Ordering Paragraph ("OP") 2.

[2] No formal limits or ratable rates are set beyond the term of the BPP. Approval for any electrical capacity procurement beyond the term of the BPP will be sought through an application.

c) Delivery years two and onward maximum annual electrical capacity procurement limits are equal to the difference between: (1) PG&E's forecast electrical capacity requirement to meet its RA requirement (i.e., peak annual hour load using a 1-in-2 year load forecast multiplied by 117 percent); and (2) the forecast Net Qualifying Capacity of PG&E's committed resources[3] and planned preferred resources.[4]

d) Ratable rates equal to the annual electrical capacity procurement limits divided by the number of years between the delivery year and the transaction year apply for delivery years two and onward and reflect the maximum capacity procurement of non-preferred electrical capacity allowed under the BPP in that year. For example, the ratable rate for delivery Year 4 is one-third the annual electrical capacity procurement limit for Year 4 (i.e., the Year 4 electrical capacity procurement limits divided by the annual time difference between Year 4 and Year 1). The unused portion of each year's ratable rate accumulate year-to-year, producing a cumulative ratable rate for each delivery year. Tables C-1 and C-2 contain PG&E's procurement limits for electrical capacity for the CPUC Mandated Scenario and PG&E's Alternative Scenario, respectively. Procurement at two-times the ratable rate, subject to the electrical capacity procurement limits, for delivery Years 2 through 5 is allowed if the prompt 12-month forward on-peak implied market heat rate at the time of execution is less than the two-standard deviation historical high value provided in Table C-3. Otherwise, procurement at one-times the ratable rate is used.

e) A transaction counts against the annual electrical capacity procurement limits and ratable rates in the year the contract is effective.[5] A transaction is compliant with PG&E's authorized procurement limits and ratable rates if, at the time the contract becomes effective, the transaction does not cause PG&E to exceed its procurement limit or ratable rate for the applicable year. A transition from a two-times ratable rate to a one-times ratable rate within a given year will not cause any transaction activity that occurred

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[3] Assuming no re-contracting of resources that are not preferred.

[4] For purposes of calculating PG&E's annual electrical capacity procurement limits and compliance with such limits, preferred resources are Energy Efficiency programs, Demand Response programs, Renewable Sources, Distributed Generation including Combined Heat and Power ("CHP") resources (or those resources qualified to count toward the Commission's CHP goals), and Energy Storage Program procurement including procurement of preferred resources above the Commission's targets or goals.

[5] Procurement at two-times the ratable rate is allowed only when the contract is effective upon execution since the ability to procure at this level is determined at the time of execution.

prior to the transition date to be non-compliant with PG&E's ratable rates, provided that such transactions complied with the applicable ratable rate when executed.

f) On occasion, whether due to the lumpiness of procurement, Commission mandated procurement (such as non-renewable, non-CHP Qualifying Facilities, non-Energy Storage, or unique and fleeting opportunities), transactions in a given year may exceed the electrical capacity procurement limits and/or ratable rates for that year. For these transactions, PG&E will request from the Commission an exemption from the annual electrical capacity procurement limits and/or ratable rates as necessary when seeking approval for the transaction.

TABLE C-1
PACIFIC GAS AND ELECTRIC COMPANY
CPUC MANDATED SCENARIO
ELECTRICAL CAPACITY PROCUREMENT AND 1 X RATABLE RATE LIMITS (MW)
CONFIDENTIAL

Delivery Year	Procurement Limit (MW)	1 x RR in 2015	1 x RR in 2016	1 x RR in 2017	1 x RR in 2018
2017	[redacted]	[redacted]	n/a	n/a	n/a
2018	[redacted]	[redacted]	[redacted]	n/a	n/a
2019	[redacted]	[redacted]	[redacted]	[redacted]	n/a
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE C-2
PACIFIC GAS AND ELECTRIC COMPANY
PG&E ALTERNATIVE SCENARIO
ELECTRICAL CAPACITY PROCUREMENT AND 1 X RATABLE RATE LIMITS (MW)
CONFIDENTIAL

Delivery Year	Procurement Limit (MW)	1 x RR in 2015	1 x RR in 2016	1 x RR in 2017	1 x RR in 2018
2017	[redacted]	[redacted]	n/a	n/a	n/a
2018	[redacted]	[redacted]	[redacted]	n/a	n/a
2019	[redacted]	[redacted]	[redacted]	[redacted]	n/a
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE C-3
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL CAPACITY IMPLIED MARKET HEAT RATE MARKET CONDITION MEASURE

Line No.	Measure	Value (MMBtu/MWh)
1	Two Standard Deviation High	[redacted]

The forward power curves used to calculate the two-standard-deviation measure span periods that predate the January 2013 start-date of California's Cap-and-Trade Program. In contrast, the forward curve used to calculate the Implied Market Heat Rate ("IMHR") that is to be calculated at the time of procurement and compared to the measure extends beyond December 2012. Because implied greenhouse gas ("GHG") cost is embedded in the post December 2012 monthly forward prices, an adjustment to the relevant monthly forward prices is necessary when calculating the IMHR at the time of procurement. In calculating IMHR, forward prices for delivery months January 2013 and after will be reduced.[7] For the calculation of this reduction, market-based forward GHG price curves will be used.

2. Electric Energy Procurement Limits and Ratable Rates

PG&E's BPP includes the following requirements for procurement limits and ratable rates for electric energy:

a) The procurement limits and ratable rates apply to electric energy transactions with deliveries beyond the prompt month (e.g., for electric

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6 [redacted]

7 Reduction in on-peak power price for months January 2013 and after will be calculated as the product of: (1) the average of the historical 12-month forward on-peak IMHR for the historical period used for the calculation of the Market Condition Measure; (2) the GHG emissions from natural gas of 0.05307 metric-tons/Millions of British Thermal Units ("MMBtu"); and (3) the GHG price for that year.

energy transactions occurring in March 2015, procurement limits and ratable rates shall apply to contract deliveries in May 2015 and beyond).[8] No procurement limits apply to current month and Prompt Month transactions in order to allow PG&E to meet its forecast requirements.

b) Monthly electric energy procurement limits for purchase and sales transactions are determined by the sum of: (i) the gross net short position (i.e., the absolute value of the sum of all hourly net short positions) for each month based on economic dispatch of PG&E's existing portfolio and delta adjusted hedge volumes assuming a two-standard deviation historical low implied market heat rate; (ii) the gross net long position (i.e., the absolute value of the sum of all hourly net long positions) for each month based on economic dispatch of PG&E's existing and planned portfolio and delta adjusted hedge volumes assuming a two-standard deviation historical high implied market heat rate. Tables C-4 and C-5 contain PG&E's procurement limits for electrical energy for the CPUC Mandated Scenario and PG&E Alternative Scenario, respectively. These limits, filed as monthly quantities, set the maximum allowable net forward purchase and sales transactions for the duration of this BPP.

[8] No formal limits or ratable rates are set beyond the term of the BPP. Approval for any electric energy procurement beyond the term of the BPP will be sought through an application.

TABLE C-4
PACIFIC GAS AND ELECTRIC COMPANY
CPUC MANDATED SCENARIO
ELECTRIC ENERGY PROCUREMENT AND 1 X RATABLE RATE LIMITS (GWH)
CONFIDENTIAL

Line No.	Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Jan	[redacted]									
2	Feb										
3	Mar										
4	Apr										
5	May										
6	Jun										
7	Jul										
8	Aug										
9	Sep										
10	Oct										
11	Nov										
12	Dec										

TABLE C-5
PACIFIC GAS AND ELECTRIC COMPANY
PG&E ALTERNATIVE SCENARIO
ELECTRIC ENERGY PROCUREMENT AND 1 X RATABLE RATE LIMITS (GWH)
CONFIDENTIAL

Line No.	Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Jan	[redacted]									
2	Feb										
3	Mar										
4	Apr										
5	May										
6	Jun										
7	Jul										
8	Aug										
9	Sep										
10	Oct										
11	Nov										
12	Dec										

c) Annual rolling year (i.e., rolling 12-month) ratable procurement limits shall apply to PG&E’s purchase and sale of electric energy products. The annual ratable rate shall equal 100 percent of the sum of the monthly procurement limits for Year 1 (i.e., Months 1 to 12), 50 percent for Year 2 (i.e., Months 13 to 24), 33 percent for Year 3 (i.e., Months 25 to 36), and so on, as shown in Table C-6. The ratable rate methodology will allow for electric energy purchases of two times the ratable rate for delivery Year 2 through Year 5 when certain market conditions are present as set forth below, subject to the individual monthly procurement limits. The operative transaction limit for purchases in delivery Year 2 through Year 5 are set as follows: (1) two times the ratable rate if the prompt 12-month forward on-peak power price[9] is less than the two-standard deviation high value contained in Table C-7; and (2) one times the ratable rate if the 12-month forward on-peak power price is greater than or equal to the two-standard deviation high value contained in Table C-7. The ratable rate limit for delivery Year 6 through Year 10 is one times the ratable rate for purchase.

[9] Market quotes for NP-15 on-peak forwards.

The forward power curves used to calculate the two-standard-deviation measure span periods that predate the January 2013 start-date of California's Cap-and-Trade Program. In contrast, the forward curve used to calculate the 12-month forward on-peak power price that is to be calculated at the time of procurement and compared to the measure extends beyond December 2012. Because implied GHG cost is embedded in the post-December 2012 monthly forward prices, an adjustment to the relevant monthly forward prices is necessary. Therefore, forward prices for delivery months January 2013 and after will be reduced.[10] For the calculation of this reduction, market-based forward GHG price curves will be used.

TABLE C-6
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC ENERGY RATABLE RATE AUTHORITY

Line No.	Period	From Delivery Month	To Delivery Month	Ratable Rate (RR) As % of Monthly Procurement Limit	2 x RR
1	Year 1	Prompt + 1	Prompt + 12	100.0%	100.0%
2	Year 2	Prompt + 13	Prompt + 24	50.0%	100.0%
3	Year 3	Prompt + 25	Prompt + 36	33.3%	66.7%
4	Year 4	Prompt + 37	Prompt + 48	25.0%	50.0%
5	Year 5	Prompt + 49	Prompt + 60	20.0%	40.0%
6	Year 6	Prompt + 61	Prompt + 72	16.7%	n/a
7	Year 7	Prompt + 73	Prompt + 84	14.3%	n/a
8	Year 8	Prompt + 85	Prompt + 96	12.5%	n/a
9	Year 9	Prompt + 97	Prompt + 108	11.1%	n/a
10	Year 10	Prompt + 109	Prompt + 120	10.0%	n/a

d) Energy-only products transacted during the term of this BPP shall count against the electric energy purchase and sales monthly procurement limits and ratable rate limits. Energy-only products include energy-only tolling contracts, heat rate options, and fixed-price forward non-renewable energy transactions. The quantities counted against the limit will be the forecasted expected energy output of the contract or resource at the time of evaluation. Paired transactions (e.g., spreads, collars, energy exchanges) shall count as a single transaction (e.g., one buy and one sell equals one transaction) in the closest delivery period to measure against the limit and ratable rate. Locational basis contracts will not count against the limits, to avoid double

10 Reduction in on-peak power price for months January 2013 and after will be calculated as the product of: (1) the average of the historical 12-month forward on-peak IMHR for the historical period used for the calculation of the Market Condition Measure; (2) the GHG emissions from natural gas of 0.05307 MMBtu; and (3) the GHG price for that year.

counting with the position with which the basis would be paired to complete a single transaction. Similarly, Congestion Revenue Rights shall not count against electric energy procurement or ratable rate limits as their use is already governed by Appendix I (Congestion Revenue Rights). RA-tolling contracts and firm energy imports that can be used to meet RA requirements shall not count against the electric energy procurement or ratable rate limits as these products may be required to meet PG&E's RA requirement. Additionally, products that do not financially hedge costs or otherwise alter PG&E's procurement cost To-expiration Value-at-Risk ("TeVaR") (e.g., Indexed-priced electric energy transactions) shall not count against electrical energy procurement or ratable rate limits. Absolute notional volumes for all transactions will be used when counting against the procurement limits.

TABLE C-7
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC ENERGY NP-15 ON-PEAK POWER PRICE MARKET CONDITION MEASURE

Line No.	Measure	Value ($/MWh)
1	Two Standard Deviation High	[redacted]

B. Natural Gas Procurement Limits

1. Natural Gas Procurement Limits and Ratable Rates

PG&E is authorized to execute natural gas transactions for delivery periods up to ten (10) years using the approved products (Appendix A) and procurement methods and processes (Appendix B) and according to the Hedging Plan (Appendix E) of this BPP. The procurement limits and ratable rates in this Appendix C define limits for PG&E's natural gas procurement authority.

Procurement limits and ratable rates apply to natural gas transactions with delivery months beyond the prompt month. PG&E will net purchases and sales of natural gas for purposes of assessing compliance with its procurement limits. PG&E will establish monthly gas procurement limits as the sum of forecast portfolio gas requirements minus delta adjusted hedges for each month assuming a two-standard deviation high IMHR based on: (1) economic dispatch the portfolio; and (2) an equivalent volume of natural gas that would be required to serve the forecast net-short electrical energy position. Tables C-8 and C-9 below contain PG&E gas purchase procurement limits, displaying the maximum allowable net forward procurement for natural gas for the CPUC Mandated Scenario and PG&E's Alternative Scenario, respectively.

TABLE C-8
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PROCUREMENT AND 1 X RATABLE
RATE LIMITS – CPUC MANDATED SCENARIO
(MILLION MMBTU) CONFIDENTIAL

Line No.	Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Jan	[redacted]									
2	Feb										
3	Mar										
4	Apr										
5	May										
6	Jun										
7	Jul										
8	Aug										
9	Sep										
10	Oct										
11	Nov										
12	Dec										

TABLE C-9
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PROCUREMENT AND 1 X RATABLE
RATE LIMITS – PG&E ALTERNATIVE SCENARIO
(MILLLION MMBTU) CONFIDENTIAL

Line No.	Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Jan	[redacted]									
2	Feb										
3	Mar										
4	Apr										
5	May										
6	Jun										
7	Jul										
8	Aug										
9	Sep										
10	Oct										
11	Nov										
12	Dec										

The annual ratable rate equals 100 percent of the sum of the monthly procurement limits for Year 1, 50 percent for Year 2, 33 percent for Year 3, and so on, as shown in Table C-10. The ratable rate methodology will allow for net natural gas purchases and sales of two times the ratable rate for delivery Year 2 through Year 5 when certain market conditions are present, subject to individual monthly procurement limits. The operative transaction limit for net purchases and sales in delivery Year 2 through Year 5 are as follows:

1. Two times the ratable rate if the prompt 12-month forward PG&E Citygate gas price is less than the two-standard deviation high value contained in Table C-11.

2. One times the ratable rate if the prompt 12-month forward natural gas price is greater than or equal to the two-standard deviation high value contained in Table C-11.

TABLE C-10
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS RATABLE RATE AUTHORITY

Line No.	Period	From Delivery Month	To Delivery Month	Ratable Rate (RR) As % of Monthly Procurement Limit	2 x RR
1	Year 1	Prompt + 1	Prompt + 12	100.00%	100.0%
2	Year 2	Prompt + 13	Prompt + 24	50.00%	100.0%
3	Year 3	Prompt + 25	Prompt + 36	33.30%	66.7%
4	Year 4	Prompt + 37	Prompt + 48	25.00%	50.0%
5	Year 5	Prompt + 49	Prompt + 60	20.00%	40.0%
6	Year 6	Prompt + 61	Prompt + 72	16.70%	n/a
7	Year 7	Prompt + 73	Prompt + 84	14.30%	n/a
8	Year 8	Prompt + 85	Prompt + 96	12.50%	n/a
9	Year 9	Prompt + 97	Prompt + 108	11.10%	n/a
10	Year 10	Prompt + 109	Prompt + 120	10.00%	n/a

TABLE C-11
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PRICE MARKET CONDITION MEASURE CONFIDENTIAL

Line No.	Measure	Value$/MMBtu
1	Two-standard-deviation high	[redacted]

A one-times ratable rate shall apply for net purchases and sales in delivery Year 6 through Year 10. Paired transactions (e.g., spreads, collars) shall count as a single hedge quantity (one buy and one sell equals one hedge) to measure against the limit and ratable rate. Similarly, basis contract will not count against the limits, to avoid double counting with the New York Mercantile Exchange position with which the basis would be paired to complete a single hedge. Products that do not financially hedge costs or otherwise alter procurement cost or TeVaR (e.g., Index-priced natural gas) do not count against natural gas monthly procurement or annual ratable rate limits. Transactions will be measured at their notional (i.e., not delta-adjusted) contract quantity, but the net open position calculation used to set the monthly procurement and annual ratable rates will use delta-adjusted volumes for gas products.

2. Pipeline Capacity Procurement Limits

PG&E may also procure natural gas pipeline capacity in order to purchase natural gas supplies in a producing basin or at a border point and then transport the gas to the PG&E Citygate. PG&E is authorized to obtain gas pipeline capacity to the extent necessary to support delivery of gas from gas receipt points to the generator burner-tip. PG&E may contract for gas pipeline capacity to meet each generator's peak annual requirement. If gas transportation capacity is temporarily not required or uneconomic to transport gas for portfolio demand, PG&E will attempt to market the surplus capacity or supply to the extent allowed by the tariff of the gas transportation provider.

TABLE C-12
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PIPELINE CAPACITY PROCUREMENT LIMITS
CONFIDENTIAL

Line No.	Limit	Description
1	Volume Limit	Peak annual demand for each generator in portfolio
2	Term Limit	Up to ten years, subject to BPP-approval requirements.

TABLE C-13
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS PIPELINE CAPACITY PROCUREMENT LIMITS
CONFIDENTIAL

Line No.	Year	MMBtu/d
1	2015	[redacted]
2	2016	
3	2017	
4	2018	
5	2019	
6	2020	
7	2021	
8	2022	
9	2023	
10	2024	

3. Natural Gas Storage Procurement Limits

To reliably meet PG&E's Electric Portfolio demand, PG&E may procure natural gas storage services. PG&E is authorized to procure storage up to the following limits:

a) Withdrawal Limit – Withdrawal equal to the largest difference between the maximum daily portfolio demand forecast and the expected demand forecast for each month throughout the year.

b) Injection Limit – Injection equal to the largest difference between minimum daily forecast demand and expected daily demand for each month throughout the year.

c) Limit calculations are based on PG&E's monthly gas burn forecast, assuming economic dispatch under an implied market heat rate that is two standard deviations higher than the base case.

d) Storage Inventory Capacity Limit – Calculated to secure enough inventory for [redacted] days of withdrawal as calculated above (i.e., [redacted] times the Storage Withdrawal Limit).

TABLE C-14
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS STORAGE PROCUREMENT LIMITS
CONFIDENTIAL

Line No.	Limit	Description
1	Storage Volume Limits	Withdrawal Limit – Withdrawal equal to the largest difference between the maximum daily portfolio demand forecast and the expected demand forecast for each month throughout the year. Injection Limit – injection equal to the largest difference between minimum daily forecast demand and expected daily demand for each month throughout the year. Inventory Limit – [redacted] times the Withdrawal Limit
2	Term	Up to 10 years, subject to BPP-approval requirements.

TABLE C-15
PACIFIC GAS AND ELECTRIC COMPANY
NATURAL GAS STORAGE PROCUREMENT LIMITS
CONFIDENTIAL

Year	Withdrawal Capacity MMBtu/d	Injection Capacity MMBtu/d	Inventory Million MMBtu
2015	[redacted]		
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			

C. GHG Procurement Limits

1. Maximum Volume Limits

Consistent with D.12-04-046, specific overall volume limits for PG&E's GHG product procurement will correspond to the actual and forecasted GHG emissions for PG&E's facilities, certain tolling agreements, and electric imports.

The California Air Resources Board's ("CARB") regulations also set limits on the number of allowances that can be held, and offsets that can be used for compliance. The Cap-and-Trade regulations restrict PG&E from purchasing more than 40 percent of the allowances offered at each auction occurring prior to 2015, and restrict PG&E from purchasing more than 25 percent of the allowances offered at each auction from 2015 onward. These limits will cap the amount of GHG Products PG&E will procure. PG&E will procure GHG Products consistent with regulations established regarding the use of such products for compliance with Cap-and-Trade. PG&E may purchase GHG Products in excess of its annual compliance requirements and may "bank" surplus GHG Products to use in future compliance years in accordance with its procurement strategy provided in Appendix G and the GHG procurement limits set forth below.

In the current year, PG&E may purchase GHG Products to fulfill 100 percent of its current net remaining compliance obligation and its forecasted compliance obligation for the remainder of the current year. In addition, in the current year PG&E may purchase a portion of its forecasted compliance obligation for the following three compliance years not to exceed a set percentage in total for each year. PG&E will not purchase GHG Products with vintages more than three years from the current year. Finally, PG&E will not purchase more than eight (8) percent of its direct compliance obligation, as defined below, in the form of offsets, provided these purchases also stay within the overall GHG product procurement limits identified below.

The procurement limit sets the maximum amount of GHG Products PG&E may purchase in the current year to fulfill its "direct compliance obligation," defined as the tons of emissions for which PG&E has an obligation to retire allowances on its own behalf as a regulated entity under CARB's Cap-and-Trade Program, and/or is otherwise obligated to procure GHG Products for a third party that is a regulated entity under the Cap-and-Trade Program (i.e., certain contractual arrangements where PG&E is contractually responsible, or could elect to assume that responsibility, for procuring GHG Products for a third party). A "purchase" is defined as taking title of the GHG product when it is delivered. Thus, forward purchases count against the procurement limit in the year delivered, which may not be the current year.

PG&E's Direct Compliance Obligation Purchase Limit for the current year is calculated as:

$$L_{CY} = max(A + FD_{CY} + 0.6FD_{CY+1} + 0.4FD_{CY+2} + 0.2FD_{CY+3}, 0)$$

Where:

"L" is the maximum number of GHG Products PG&E can purchase for purposes of meeting its direct compliance obligation.

"CY" is the Current Year, i.e., the year in which PG&E is transacting in the market.

"A" is PG&E's net remaining compliance obligation to date, calculated as the sum of the actual emissions for which PG&E is responsible for retiring allowances (or obligated to purchase for a third party) up to the Current Year, minus the total allowances or offsets PG&E has purchased up to the Current Year that could be retired against those obligations. This term in the calculation ensures PG&E is always able to buy sufficient GHG Products to cover any prior years' shortfalls, given that actual emissions may end up being less than forecast and/or prior decisions about how much procurement to do.

"FD" is PG&E's "forecasted compliance obligation", the projected amount of emissions for which PG&E is responsible for retiring GHG Products, or obligated to purchase for a third party, calculated using an IMHR that is two-standard deviations above the expected IMHR.[11]

If this equation results in a negative number in a given year, PG&E's Direct Compliance Obligation Purchase Limit for that year should be set at zero.

In addition to its Direct Compliance Obligation Purchase Limit, in the current year PG&E will not purchase GHG Products for future years greater than the percentage allowed in the Direct Compliance Obligation Purchase Limit formula. Therefore, for the prompt year (current year plus one) PG&E will not purchase in aggregate during the current year more than 60 percent of the prompt year's forecasted compliance obligation (as calculated above). Similarly, the percentages for current year plus two and current year plus three are 40 percent and 20 percent, respectively.

Consistent with Ordering Paragraph 9 of D.12-04-046, Table C-16 details estimated forecast of the amount of GHG compliance instruments (in metric tons carbon dioxide equivalents) that correspond to the maximum procurement levels applicable to both the 2015 and 2016 periods detailed in Table C-17.

[11] The IMHR two-standard deviations above the expected IMHR is calculated as follows: (1) the monthly historic IMHR is calculated by dividing monthly forward electricity prices by monthly forward gas prices for the period 2003 through 2011, yielding the forward monthly IMHR for this period; (2) monthly standard deviations of the forward monthly IMHR are then calculated separately for January through December; (3) the IMHR two-standard deviations above the expected IMHR is equal to the forward IMHR plus the standard deviation calculated in (2) multiplied by 2.0. The forward electricity prices to be used in calculating forecasted compliance obligations for the Direct Compliance Obligation Purchase Limits are then calculated by multiplying the IMHR at two-standard deviations above the expected IMHR by the forward gas price.

TABLE C-16
PACIFIC GAS AND ELECTRIC COMPANY
COMPLIANCE INSTRUMENT FORECAST FOR 2015 THROUGH 2019
MILLION MTCO$_2$E
CONFIDENTIAL

Line No.	Year	Base Case	Two Standard Deviation High IMHR Case
1	2015	[redacted]	
2	2016		
3	2017		
4	2018		
5	2019		

TABLE C-17
PACIFIC GAS AND ELECTRIC COMPANY
DIRECT COMPLIANCE OBLIGATION PURCHASE LIMITS FOR 2015 AND 2016
MILLION MTCO$_2$E
CONFIDENTIAL

Line No.	Limit[12]	Limit for 2015	Limit for 2016
A	[redacted]		
1			
2			
3			
4			
A+1+2+3+4			

2. Financially Hedging Greenhouse Gas Compliance Instrument Price Risk

PG&E’s purchase of approved GHG Products (see Appendix A) to hedge GHG price risk will be subject to the procurement limit set forth below.

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12 [redacted]

The "financial exposure" purchase limit sets the specific limit on the amount of GHG Products PG&E can purchase to hedge its financial exposure to GHG costs under the Cap-and-Trade Program. As with the Direct Compliance Obligation Purchase Limit formula above, this is a purchase limit, meaning the number that emerges from this calculation would set the maximum amount of GHG Products PG&E is allowed to purchase in the current year for purposes of hedging its financial exposure. "Purchase" is defined as taking title of the GHG product when it is delivered. PG&E will not purchase allowances or offsets for hedging purposes with vintages more than three years from the current year.

PG&E's Financial Exposure Purchase Limit is calculated as:

FLCY = 20% * FECY + 10% * FECY+1 + 5% * FECY+2 + 2.5% * FECY+3 – B

Where:

"FL" is the maximum number of GHG Products PG&E can purchase for purposes of hedging its financial exposure to GHG costs.

"CY" is the current year, i.e., the year in which PG&E is transacting in the market.

"FE" is an estimate of PG&E's financial exposure to GHG costs that will, or are anticipated to be, embedded in the price of energy, calculated based on the tons of GHG emissions for which PG&E believes it will bear the costs through an embedded cost of such emissions as reflected in energy prices. This amount does not include the costs PG&E anticipates incurring as a result of its direct compliance obligation as "direct compliance obligation" is defined above.

"B" is PG&E's net purchases of GHG Products to date for hedging purposes, calculated as the total purchases of GHG Products for purposes of hedging PG&E's financial exposure up to the current year, minus those GHG Products sold up to the current year. This term helps ensure that if

PG&E hedged considerably in prior years and those hedges did not pay out (i.e., the price PG&E saw in the market for GHG Products stayed below what PG&E paid for a GHG Product and so PG&E did not sell the instrument), that gets factored into the amount of additional hedging PG&E is allowed to undertake.

If this equation results in a negative number in a given year, PG&E's Financial Exposure Purchase Limit for that year will be set at zero.

Consistent with Ordering Paragraph 9 of D.12-04-046, Table C-18 details estimated forecast of PG&E's financial exposure to GHG costs that will, or are anticipated to be, embedded in the price of energy (in metric tons carbon dioxide equivalents) that correspond to the maximum procurement levels applicable to both the 2015 and 2016 periods detailed in Table C-19 for the CPUC Mandated Scenario. Tables C-20 and C-21 provide the same information for PG&E's Alternative Scenario.

TABLE C-18
PACIFIC GAS AND ELECTRIC COMPANY
INDIRECT COMPLIANCE INSTRUMENT FORECAST FOR 2015 THROUGH 2019
CPUC MANDATED SCENARIO
MILLION MT CO_2E

Line No.	Year	Financial Exposure[13]
1	2015	[redacted]
2	2016	
3	2017	
4	2018	
5	2019	

13 [redacted]

TABLE C-19
FINANCIAL EXPOSURE PURCHASE LIMITS FOR 2015 AND 2016
CPUC MANDATED SCENARIO
MILLION MT CO_2E

Line No.	Limit[14]	Limit for 2015	Limit for 2016
1	[redacted]		
2			
3			
4			
B			
1+2+3+4-B			

TABLE C-20
PACIFIC GAS AND ELECTRIC COMPANY
INDIRECT COMPLIANCE INSTRUMENT FORECAST FOR 2015 THROUGH 2019
PG&E ALTERNATIVE SCENARIO
MILLION MT CO_2E

Line No.	Year	Financial Exposure[15]
1	2015	[redacted]
2	2016	
3	2017	
4	2018	
5	2019	

14 [redacted]

15 [redacted]

TABLE C-21
PACIFIC GAS AND ELECTRIC COMPANY
FINANCIAL EXPOSURE PURCHASE LIMITS FOR 2015 AND 2016
PG&E ALTERNATIVE SCENARIO
MILLION MT CO_2E

Line No.	Limit[16]	Limit for 2015	Limit for 2016
1	[redacted]		
2			
3			
4			
B			
1+2+3+4-B			

16 [redacted]

APPENDIX D

DESCRIPTION AND EVALUATION OF CPUC MANDATED AND PG&E ALTERNATIVE SCENARIOS

A. Introduction

This Appendix provides a description and evaluation of two separate scenarios for bundled procurement needs between 2015 and 2024. The first scenario is the California Public Utilities Commission ("CPUC" or "Commission") Mandated Scenario. This scenario includes load and resource assumptions mandated by the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* issued May 6, 2014 ("Scoping Memo"). This CPUC Mandated Scenario is based on the standardized planning assumptions that were established in the *Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and 2014-15 CAISO TPP* issued May 14, 2014 ("Planning Assumptions"). Pacific Gas and Electric Company ("PG&E") neither explicitly nor implicitly adopts these planning assumptions as its own and is submitting this CPUC Mandated Scenario and its results as directed by the Scoping Memo.
The CPUC Mandated Scenario is described in Section B of this Appendix. Section B also provides an evaluation of the CPUC Mandated Scenario which includes the resulting: (1) capacity and energy load-resource balance tables and (2) To-expiration Value-at-Risk ("TeVaR") measure for the CPUC Mandated Scenario.

The second scenario included in this Appendix is the PG&E Alternative Scenario. The PG&E Alternative Scenario is based on the CPUC Mandated Scenario, but includes three demand-side modifications which impact the bundled load forecast. Specifically, the PG&E Alternative Scenario includes higher forecasts for Community Choice Aggregation ("CCA"), Direct Access ("DA"), and Distributed Generation ("DG").

The only supply-side resources modified in the PG&E Alternative Scenario are the reduced renewable volumes needed to comply with the Renewables Portfolio Standard ("RPS") procurement targets resulting from an overall lower bundled load forecast. The PG&E Alternative Scenario is described in more detail in Section C of this Appendix. In addition, Section C also includes the resulting: (1) capacity and energy load-resource balance tables and (2) TeVaR measure for the PG&E Alternative Scenario.

B. CPUC Mandated Scenario

Below, PG&E provides a description of each of the load and resource assumptions included in the CPUC Mandated Scenario.

1. Load Forecast

As directed in the Scoping Memo, the load forecast in Table D-1, lines 1-5 are from the mid-case of the California Energy Commission's ("CEC") 2013 Integrated Energy Policy Report California Energy Demand and reflect the mid-case of the CEC's Additional Achievable Energy Efficiency projections.

The Demand Response ("DR") values in Table D-1, line 7 include those DR programs reported in the most recent April Load Impact report PG&E has filed with the Commission. They represent the *ex-ante* August load impact in a 1-in-2 weather year condition.

2. Existing and Planned Resources

PG&E-owned fossil resources (Table D-1, line 15) include two combined cycle plants (Gateway and Colusa) and a series of 10 gas-fired reciprocating engines that replaced the Humboldt Bay Power Plant. In addition, PG&E owns three fuel cell electric generating facilities totaling 3 megawatts ("MW") of installed capacity on two State of California properties: California State University – East Bay and San Francisco State University.

PG&E owns and operates two nuclear power units at the Diablo Canyon Power Plant with a combined peak capacity of 2,240 MW (Table D-1, line 16).

PG&E owns and operates various hydroelectric facilities (Table D-1, line 17), including run-of-river and dispatchable hydroelectric facilities as well as the Helms Pumped Storage Facility. Many of these facilities are RPS-eligible resources.

Under PG&E's Solar Photovoltaic ("PV") program adopted in Commission Decision 10-04-052, PG&E owns 152 MW (installed capacity) of dispersed, midsized (typically 1 to 20 MW) solar PV installations within PG&E's service territory. PG&E also owns three small solar PV facilities in San Francisco that entered commercial operations in 2007. All of these are reflected in Table D-1, line 18, which represents their capacity contribution at the time of the peak.

PG&E owns two 7-hour storage sodium sulfur battery systems. The 2 MW (installed capacity) Vaca-Dixon Storage Pilot Project and the 4 MW (installed capacity) Yerba Buena Battery Storage Pilot Project became operational in September and May 2013, respectively. These are reflected in Table D-1, line 19, which represents their capacity contribution at the time of the peak.

At the beginning of 2014, the Kings River Conservation District contract is the only California Department of Water ("CDWR" or "DWR") contract allocated to PG&E

that has not yet expired (Table D-1, line 20). This contract is scheduled to expire late 2015.

PG&E has Power Purchase Agreements with approximately 150 operating Qualifying Facilities ("QF") (Table D-1, line 21). The QF contracts cover a wide range of technologies including RPS-eligible and fossil resources.

In addition to RPS-eligible QFs, PG&E has other contracts with RPS-eligible resources (Table D-1, line 22). PG&E developed RPS assumptions for the CPUC Mandated Scenario consistent with PG&E's Draft 2014 RPS Plan.[1] The non-QF RPS portfolio reflected includes all executed contracts at 100 percent of negotiated energy deliveries and online dates reflect the best available information on the development status of projects under contract to PG&E.

For the CPUC Mandated Scenario, generic renewable resources (Table D-1, line 23) represents: (1) CPUC-approved programs including the Renewable Auction Mechanism; (2) small-scale bioenergy Feed-in-Tariff ("FIT") procurement required pursuant to Senate Bill 1122 and FIT procurement under the Renewable Market Adjusting Tariff program; (3) PG&E's PV program; and (4) additional procurement needed to comply with the RPS procurement targets. The latter is used to fill the RPS-specific net short position with generic RPS resources using the following technology mix: 30 percent wind and 70 percent solar PV. This technology mix is PG&E's current best estimate of a blend of technologies for long-term RPS procurement purposes. Commercial negotiations and market factors will ultimately determine the

[1] Draft 2014 PG&E Renewable Energy Procurement Plan, filed in R.11-05-005, June 4, 2014.

technology makeup of PG&E's renewable portfolio, so the numbers presented here will change over time.

CPUC Decision 13-10-040 established a 2020 procurement target for PG&E of 580 MW of installed capacity of new energy storage units (Table D-1, line 24). PG&E's forecast on this line is consistent with those outlined in the Planning Assumptions and reflects capacity to become operational in 2017, reaching the full installed capacity of 580 MW by 2020. Values shown on this line represent the capacity contribution at the time of the peak.

PG&E's Other Bilateral Contractual Resources (Table D-1, line 25) consists of bilateral contracts including: (1) incremental supply-side Combined Heat and Power ("CHP"); (2) various tolling contracts; (3) large hydro contracts; (4) the Puget Power and Light Company exchange contract; and (5) Resource Adequacy contracts.

TABLE D-1
PACIFIC GAS AND ELECTRIC COMPANY
CPUC MANDATED SCENARIO
CAPACITY BALANCE

		August MW									
Line	**Peak PG&E Load Calculations**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1	Forecast Total Peak-Hour 1-in-2 Demand (+)	21,330	21,404	21,470	21,595	21,736	21,891	22,014	22,138	22,212	22,272
2	CCA (-)	-85	-85	-84	-83	-82	-82	-81	-80	-79	-79
3	Direct Access Loads (-)	-1,269	-1,256	-1,244	-1,233	-1,222	-1,212	-1,202	-1,191	-1,180	-1,168
4	Distributed Generation (PV) (-)	-646	-698	-724	-756	-793	-839	-897	-968	-1,051	-1,144
5	Distributed Generation (Other) (-)	-194	-205	-215	-224	-233	-242	-249	-255	-260	-264
6	Adjustment for CCA/DA/DG Overlap (+)	0	0	0	0	0	0	0	0	0	0
7	Demand Response/Interruptible Programs (-)	-701	-703	-705	-706	-708	-710	-710	-713	-715	-715
8	***Subtotal: Adjustments Peak-Hour Demand (Sum lines 2 thru 7)***	***-2,897***	***-2,947***	***-2,972***	***-3,003***	***-3,039***	***-3,085***	***-3,139***	***-3,207***	***-3,285***	***-3,371***
9	**Adjusted Peak-Hour Demand (Line 1 + Line 8)**	**18,433**	**18,456**	**18,498**	**18,593**	**18,697**	**18,807**	**18,875**	**18,930**	**18,926**	**18,901**
10	Coincidence Adjustment (-)	-325	-326	-326	-328	-330	-332	-333	-334	-334	-333
11	**Net Peak-Hour Demand (Sum Line 9 + Line 10)**	**18,108**	**18,131**	**18,172**	**18,265**	**18,367**	**18,475**	**18,542**	**18,597**	**18,593**	**18,568**
12	Specified Planning Reserve Margin (Line 11*17%)	**3,078**	**3,082**	**3,089**	**3,105**	**3,122**	**3,141**	**3,152**	**3,161**	**3,161**	**3,156**
13	Firm Sales Obligation (+)	0	0	0	0	0	0	0	0	0	0
14	**Firm PG&E Peak-Hour Requirement (Sum Lines 11 thru 13)**	**21,186**	**21,213**	**21,261**	**21,370**	**21,490**	**21,616**	**21,694**	**21,758**	**21,753**	**21,724**
	Existing and Planned Resources:										
15	PG&E-Owned Fossil Resources	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353
16	PG&E-Owned Nuclear Resources	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240
17	PG&E-Owned Hydroelectric Resources	3,713	3,713	3,713	3,713	3,716	3,716	3,716	3,716	3,716	3,716
18	PG&E-Owned Solar Resources	34	34	34	34	34	34	34	34	34	34
19	PG&E-Owned Energy Storage Resources	0	0	0	0	0	0	0	0	0	0
20	DWR Contractual Resources	96	0	0	0	0	0	0	0	0	0
21	Qualifying Facility (QF) Contractual Resources	[redacted]									
22	Non-QF Renewable Energy Contractual Resources	2,728	2,830	3,072	3,244	3,457	3,510	3,469	3,216	3,284	3,544
23	Generic Renewable Resources	0	0	118	117	117	470	692	1,050	1,311	1,304
24	Energy Storage Resources	0	0	50	101	151	201	252	302	352	403
25	Other Bilateral Resources	8,660	7,277	6,618	5,756	4,451	4,364	3,746	3,220	1,305	906
26	Outages	-175	-175	-175	-175	-175	-175	-175	-175	-175	-175
27	**Total Existing and Planned Resources (Sum lines 15 thru 26)**	[redacted]									
28	**Capacity Need (-) or Surplus (+) (Line 27- Line 14)**	[redacted]									

TABLE D-2
PACIFIC GAS AND ELECTRIC COMPANY
CPUC MANDATED SCENARIO
ENERGY BALANCE

		GWh									
Line	**PG&E Load Calculations**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1	Forecast Total Energy 1-in-2 Demand (+)	99,001	99,316	99,718	100,128	100,756	101,515	102,209	102,943	103,473	103,953
2	CCA (-)	-611	-605	-599	-594	-588	-583	-578	-573	-568	-562
3	Direct Access Loads (-)	-9,685	-9,586	-9,492	-9,409	-9,321	-9,246	-9,168	-9,087	-9,000	-8,915
4	Distributed Generation (PV) (-)	-2,202	-2,391	-2,484	-2,597	-2,732	-2,900	-3,116	-3,384	-3,701	-4,061
5	Distributed Generation (Other) (-)	-1,421	-1,491	-1,545	-1,599	-1,649	-1,694	-1,734	-1,768	-1,794	-1,815
6	Adjustment for CCA/DA/DG Overlap (+)	0	0	0	0	0	0	0	0	0	0
7	Demand Response/Interruptible Programs (-)	0	0	0	0	0	0	0	0	0	0
8	***Subtotal: Adjustments Energy Demand (Sum lines 2 thru 7)***	***-13,919***	***-14,072***	***-14,120***	***-14,198***	***-14,291***	***-14,424***	***-14,597***	***-14,812***	***-15,063***	***-15,352***
9	**Adjusted Energy Demand (Line 1 + Line 8)**	**85,081**	**85,244**	**85,597**	**85,930**	**86,465**	**87,091**	**87,612**	**88,131**	**88,410**	**88,601**
10	Firm Sales Obligation (+)	413	413	413	413	413	413	413	413	413	413
11	**PG&E Energy Requirement (Sum Line 9 + Line 10)**	**85,494**	**85,657**	**86,010**	**86,343**	**86,878**	**87,504**	**88,025**	**88,544**	**88,823**	**89,014**
	Existing and Planned Resources:										
12	PG&E-Owned Fossil Resources	[redacted]									
13	PG&E-Owned Nuclear Resources	[redacted]			17,619	17,532	18,463	18,550	18,545	18,549	17,584
14	PG&E-Owned Hydroelectric Resources	9,517	10,001	10,748	11,028	11,126	11,157	11,090	11,123	11,141	11,191
15	PG&E-Owned Solar Resources	343	342	340	338	336	335	333	331	329	328
16	PG&E-Owned Energy Storage Resources	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
17	DWR Contractual Resources	20	0	0	0	0	0	0	0	0	0
18	Qualifying Facility (QF) Contractual Resources	[redacted]									
19	Non-QF Renewable Energy Contractual Resources	17,791	18,291	18,441	17,120	17,917	17,919	17,640	15,262	14,937	14,656
20	Generic Renewable Resources	0	25	530	1,139	1,531	3,054	3,743	5,236	7,684	8,691
21	Energy Storage Resources	0	0	-15	-31	-46	-62	-77	-93	-108	-124
22	Other Bilateral Resources	7,722	7,831	6,963	5,820	6,378	6,520	5,276	5,052	3,441	1,944
23	**Total Existing and Planned Resources (Sum lines 12 thru 22)**	[redacted]			62,933	63,966	65,431	64,313	63,112	63,673	61,954
24	**Energy Need (-) or Surplus (+) (Line 23 - Line 11)**	[redacted]			-23,410	-22,913	-22,073	-23,712	-25,432	-25,150	-27,060

3. Evaluation of Risk

Table D-3 summarizes PG&E's evaluation of the CPUC Mandated Scenario in terms of risk by providing the resulting bundled TeVaR measure. A further description of the TeVaR methodology can be found in Appendix N.

TABLE D-3
PACIFIC GAS AND ELECTRIC COMPANY
CPUC MANDATED SCENARIO RISK

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TeVaR ($ Millions)	[redacted]									

C. PG&E Alternative Scenario

1. Load Forecast

The difference between the CPUC Mandated Scenario and PG&E Alternative Scenario is the forecasted amounts of CCA, DA, and DG departure levels.

With regard to CCA, PG&E is estimating departing load based on the current load served by existing CCAs (Marin Clean Energy (“MCE”) and Sonoma Clean Power (“Sonoma”)), combined with load that may be served by these entities, along with load that may be served by entities that are actively engaged in exploring CCA. Specifically, based on a current snapshot of activity, PG&E notes that Sonoma is phasing in additional load within the communities that are currently members of the Joint Powers Authority (“JPA”), and is actively engaging with the two cities in Sonoma County that are not currently part of the JPA, but will be considering joining before the end of 2014 (Petaluma and Rohnert Park). In the case of MCE, unincorporated Napa County has recently joined the JPA, and is expected to begin receiving service in 2015. In both cases, PG&E used 2013 estimates of the load within these areas, applied a probability adjustment of roughly 90-95 percent that they will actually proceed with CCA service, and further adjusted the loads to reflect expected opt-outs and annual load growth. Finally, PG&E recognizes there is substantial uncertainty regarding the amount of load that may be served by entities that are currently engaged in actively exploring CCA. A number of communities have undertaken a significant financial commitment to evaluate CCA, and have passed resolutions stating their intent to move down this path. In these cases, PG&E estimated the departing load by multiplying estimates of the likelihood that they will proceed to serve the amount of load within these communities, adjusted by an estimated opt-out rate and an annual load growth factor.

With regard to DA, PG&E has taken the current amount of load served under DA (approximately 9,600 gigawatt-hours ("GWh") per year) and kept it flat throughout forecast period.

With regard to DG, PG&E forecasted PV adoptions by examining historical PV adoption rates, and adjusting growth projections based on anticipated policy developments. The Compound Annual Growth Rate ("CAGR") in annual installed retail PV capacity in PG&E's territory from 2011-2013 was 27 percent. This growth has been fueled primarily by attractive project economics and the availability of more accessible financing models. From 2014 to year-end 2016, PG&E anticipates an increase in the CAGR to 29 percent as customers install systems before adjustment of the federal Investment Tax Credit and before changes to Net Energy Metering tariffs are enacted. This growth rate is in line with near term projections for California by Bloomberg New Energy Finance in their H1 2014 US PV Market Outlook report (March 2014). In 2017, PG&E estimates that annual additions will return to 2014 levels of approximately 300 MW/year, and increase relatively linearly to about 400 MW/year by 2024.

PG&E forecasted adoption of non-PV DG by the following technology categories: CHP, Fuel Cells and Other. "Other" technologies consist of wind systems and non-CHP microturbines and engines. For traditional CHP and "Other" technologies, PG&E's forecast was developed using an historic 10-year average adoption rate. These technologies are sited almost exclusively on commercial and industrial properties, and the electric rate structure and technology specifications that impact adoption economics are not expected to change substantially in the near-term. Due to limited availability of information on historic adoption prior to 2001, PG&E forecasted incremental adoption using a historical baseline of 2001. Fuel cell adoption, on the other hand, has increased in most years since 2007. Incentives available through the Self-Generation Incentive Program, declining costs, and rising system efficiencies (particularly from all-electric systems) are improving the economics of fuel cells. As a result, an exponential trend function, showing increasing rates of capacity addition, is used to develop the fuel cell forecast.

By 2024, PG&E estimates approximately 12,100 GWh of generation from retail DG facilities, which equates to 13,300 GWh of avoided procurement at the point of generation (Table D-5, sum of lines 4 and 5).

Finally, to address the overlap that may exist between these various forms of load departure, PG&E subtracted from the CCA load departures described above the DA load percentage across the service area, and the estimated amount of DG growth within these communities. This estimated DG growth was derived by applying the DG growth rates to the current proportion of DG penetration that is located within the various communities that have implemented or are actively exploring CCA.

2. Existing and Planned Resources

The PG&E Alternative Scenario has only one difference in this section in comparison to the CPUC Mandated Scenario, specifically the Generic Renewable Resources (Table D-4, line 23). The residual effect of the lower load forecast in the PG&E Alternative Scenario discussed above reduces the need for additional renewable procurement needed to comply with the RPS procurement targets.

TABLE D-4
PACIFIC GAS AND ELECTRIC COMPANY
PG&E ALTERNATIVE SCENARIO
CAPACITY BALANCE

		August MW									
Line	**Peak PG&E Load Calculations**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1	Forecast Total Peak-Hour 1-in-2 Demand (+)	21,330	21,404	21,470	21,595	21,736	21,891	22,014	22,138	22,212	22,272
2	CCA (-)	-908	-1,686	-2,159	-2,181	-2,202	-2,224	-2,247	-2,269	-2,292	-2,300
3	Direct Access Loads (-)	-1,373	-1,373	-1,373	-1,373	-1,373	-1,373	-1,373	-1,373	-1,373	-1,373
4	Distributed Generation (PV) (-)	-663	-881	-1,001	-1,128	-1,261	-1,400	-1,547	-1,701	-1,862	-2,032
5	Distributed Generation (Other) (-)	-238	-262	-286	-312	-338	-366	-394	-424	-455	-487
6	Adjustment for CCA/DA/DG Overlap (+)	89	199	271	285	299	314	330	346	363	378
7	Demand Response/Interruptible Programs (-)	-701	-703	-705	-706	-708	-710	-710	-713	-715	-715
8	***Subtotal: Adjustments Peak-Hour Demand (Sum lines 2 thru 7)***	***-3,795***	***-4,706***	***-5,254***	***-5,415***	***-5,584***	***-5,760***	***-5,942***	***-6,135***	***-6,335***	***-6,529***
9	**Adjusted Peak-Hour Demand (Line 1 + Line 8)**	**17,535**	**16,698**	**16,216**	**16,180**	**16,152**	**16,131**	**16,072**	**16,003**	**15,877**	**15,742**
10	Coincidence Adjustment (-)	-310	-296	-288	-287	-287	-286	-285	-284	-282	-280
11	**Net Peak-Hour Demand (Sum Line 9 + Line 10)**	**17,225**	**16,402**	**15,928**	**15,893**	**15,865**	**15,845**	**15,786**	**15,719**	**15,595**	**15,463**
12	Specified Planning Reserve Margin (Line 11*17%)	**2,928**	**2,788**	**2,708**	**2,702**	**2,697**	**2,694**	**2,684**	**2,672**	**2,651**	**2,629**
13	Firm Sales Obligation (+)	0	0	0	0	0	0	0	0	0	0
14	**Firm PG&E Peak-Hour Requirement (Sum Lines 11 thru 13)**	**20,153**	**19,190**	**18,636**	**18,595**	**18,563**	**18,539**	**18,470**	**18,391**	**18,246**	**18,091**
	Existing and Planned Resources:										
15	PG&E-Owned Fossil Resources	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353
16	PG&E-Owned Nuclear Resources	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240
17	PG&E-Owned Hydroelectric Resources	3,713	3,713	3,713	3,713	3,716	3,716	3,716	3,716	3,716	3,716
18	PG&E-Owned Solar Resources	34	34	34	34	34	34	34	34	34	34
19	PG&E-Owned Energy Storage Resources	0	0	0	0	0	0	0	0	0	0
20	DWR Contractual Resources	96	0	0	0	0	0	0	0	0	0
21	Qualifying Facility (QF) Contractual Resources	[redacted]									
22	Non-QF Renewable Energy Contractual Resources	2,728	2,830	3,072	3,244	3,457	3,510	3,469	3,216	3,188	3,183
23	Generic Renewable Resources	0	0	118	117	117	116	116	115	114	114
24	Energy Storage Resources	0	0	50	101	151	201	252	302	352	403
25	Other Bilateral Resources	8,633	7,165	6,273	5,426	4,118	4,030	3,642	3,156	1,305	906
26	Outages	-175	-175	-175	-175	-175	-175	-175	-175	-175	-175
27	**Total Existing and Planned Resources (Sum lines 15 thru 26)**	[redacted]									
28	**Capacity Need (-) or Surplus (+) (Line 27- Line 14)**	[redacted]									

TABLE D-5
PACIFIC GAS AND ELECTRIC COMPANY
PG&E ALTERNATIVE SCENARIO
ENERGY BALANCE

		GWh									
Line	**PG&E Load Calculations**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1	Forecast Total Energy 1-in-2 Demand (+)	99,001	99,316	99,718	100,128	100,756	101,515	102,209	102,943	103,473	103,953
2	CCA (-)	-6,499	-12,058	-15,444	-15,599	-15,755	-15,912	-16,071	-16,232	-16,395	-16,454
3	Direct Access Loads (-)	-10,479	-10,479	-10,479	-10,479	-10,479	-10,479	-10,479	-10,479	-10,479	-10,479
4	Distributed Generation (PV) (-)	-3,234	-4,291	-4,850	-5,433	-6,043	-6,679	-7,344	-8,039	-8,765	-9,525
5	Distributed Generation (Other) (-)	-1,872	-2,052	-2,239	-2,433	-2,636	-2,846	-3,063	-3,288	-3,521	-3,761
6	Adjustment for CCA/DA/DG Overlap (+)	637	1,421	1,938	2,037	2,141	2,248	2,359	2,474	2,594	2,707
7	Demand Response/Interruptible Programs (-)	0	0	0	0	0	0	0	0	0	0
8	***Subtotal: Adjustments Energy Demand (Sum lines 2 thru 7)***	***-21,446***	***-27,458***	***-31,074***	***-31,907***	***-32,771***	***-33,668***	***-34,598***	***-35,564***	***-36,565***	***-37,512***
9	**Adjusted Energy Demand (Line 1 + Line 8)**	**77,555**	**71,858**	**68,644**	**68,221**	**67,984**	**67,847**	**67,610**	**67,379**	**66,908**	**66,442**
10	Firm Sales Obligation (+)	413	413	413	413	413	413	413	413	413	413
11	**PG&E Energy Requirement (Sum Line 9 + Line 10)**	**77,968**	**72,271**	**69,057**	**68,634**	**68,397**	**68,260**	**68,023**	**67,792**	**67,321**	**66,855**
	Existing and Planned Resources:										
12	PG&E-Owned Fossil Resources	[redacted]									
13	PG&E-Owned Nuclear Resources	[redacted]			17,619	17,532	18,463	18,550	18,545	18,549	17,584
14	PG&E-Owned Hydroelectric Resources	9,517	10,001	10,748	11,028	11,126	11,157	11,090	11,123	11,141	11,191
15	PG&E-Owned Solar Resources	343	342	340	338	336	335	333	331	329	328
16	PG&E-Owned Energy Storage Resources	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
17	DWR Contractual Resources	20	0	0	0	0	0	0	0	0	0
18	Qualifying Facility (QF) Contractual Resources	[redacted]									
19	Non-QF Renewable Energy Contractual Resources	17,791	18,291	18,441	17,120	17,917	17,919	17,640	15,262	14,937	14,656
20	Generic Renewable Resources	0	25	530	1,139	1,531	1,548	1,541	1,537	1,533	1,532
21	Energy Storage Resources	0	0	-15	-31	-46	-62	-77	-93	-108	-124
22	Other Bilateral Resources	7,722	7,831	6,963	5,820	6,378	6,520	5,276	5,052	3,441	1,944
23	**Total Existing and Planned Resources (Sum lines 12 thru 22)**	[redacted]			62,933	63,966	63,926	62,111	59,413	57,521	54,795
24	**Energy Need (-) or Surplus (+) (Line 23 - Line 11)**	[redacted]			-5,701	-4,432	-4,334	-5,912	-8,380	-9,799	-12,060

3. Evaluation of Risk

Table D-6 summarizes PG&E's evaluation of the PG&E Alternative Scenario in terms of risk by providing the resulting bundled TeVaR measure. A further description of the TeVaR methodology can be found in Appendix N.

TABLE D-6
PACIFIC GAS AND ELECTRIC COMPANY
PG&E ALTERNATIVE SCENARIO
RISK

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TeVaR ($ Millions)	[redacted]									

APPENDIX E

ELECTRIC PORTFOLIO HEDGING PLAN

A. Introduction

This Appendix describes Pacific Gas and Electric Company's ("PG&E") hedging plan ("Hedging Plan") for its electric portfolio. The Hedging Plan guides PG&E's management of the commodity price risk in the portfolio. In addition, the Hedging Plan serves as a framework for California Public Utilities Commission ("CPUC" or "Commission") compliance review through the quarterly compliance reports and annual Energy Resource Recovery Account ("ERRA") proceedings.

B. Hedging Plan Structure

The Hedging Plan includes the following components:

- Plan tenor;
- Hedging targets and limits;
- Product mix strategy;
- Execution strategy;
- Conditions when it is acceptable to operate outside the hedging plan; and
- Liquidity management strategy.

The remainder of this section describes important planning aspects that are not part of the Hedging Plan.

1. Physical Supply Managed Separately From the Hedging Plan

a. Electricity

PG&E's objectives for managing the electric portfolio's exposure to physical risks are different from PG&E's objectives for managing the electric portfolio's exposure to financial risks. Therefore, PG&E manages the electric portfolio's physical electric supply separately from the electric portfolio's exposure to financial risks. In managing the electric portfolio's financial risks, PG&E's objectives are to reduce exposure of the electric portfolio to electricity price volatility, to reduce portfolio To-expiration Value-at-Risk ("TeVaR"), and ultimately to stabilize electric rates for customers.

To manage aspects of the electric portfolio other than financial risks—aspects such as operational flexibility—PG&E may procure electricity products. Such transactions for electricity products may affect the physical positions and financial positions of the electric portfolio. Various electricity risks are not managed through the Hedging Plan but through other parts of the Bundled Procurement Plan ("BPP"). Managing risks associated with differences in electricity prices between day-ahead and real-time prices are described in Appendix H, PG&E's plan for convergence bidding. Managing congestion risk is described in Appendix I, PG&E's plan for using Congestion Revenue Rights ("CRR") and participating in the California Independent System Operator's allocation and auction processes for CRRs.

b. Natural Gas

PG&E's objectives for managing the electric portfolio's exposure to physical natural gas supply risks are different from PG&E's objectives for managing the electric portfolio's exposure to financial risks associated with natural gas. Therefore, PG&E manages the electric portfolio's physical gas supply separately from the electric portfolio's exposure to financial risks. In managing the electric portfolio's financial risks associated with natural gas, PG&E's objectives are to reduce exposure of the electric portfolio to natural gas price volatility, to reduce TeVaR, and to stabilize electric rates for customers.

c. Greenhouse Gas

PG&E's objectives for managing the electric portfolio's exposure to physical greenhouse gas ("GHG") compliance instrument supply risks are different from PG&E's objectives for managing the electric portfolio's exposure to financial risks associated with GHG costs. Therefore, PG&E manages the electric portfolio's physical GHG compliance instrument supply separately from the electric portfolio's exposure to financial risks. In managing the electric portfolio's financial risks associated with GHG costs, PG&E's objectives are to reduce exposure of the electric portfolio to GHG compliance instrument price volatility, to reduce TeVaR, and to stabilize electric rates for customers.

C. Hedging Plan

1. Tenor

In the context of the Hedging Plan, tenor means the length of the delivery period to be hedged. [redacted]

[redacted]

1 [redacted]

[redacted]

2. Hedging Targets and Limits

PG&E's Hedging Plan targets and limits are defined as follows:

[redacted]

TABLE E-1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PORTFOLIO HEDGING TARGETS FOR COMMODITY HEDGING

[redacted]

[redacted]

[2] [redacted]

[redacted]

TABLE E-2
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC PORTFOLIO HEDGING LIMITS FOR COMMODITY HEDGING
[redacted]

[redacted]

3 [redacted]
4 [redacted]

[redacted]

[redacted]

[redacted]

5 [redacted]

FIGURE E-1
PACIFIC GAS AND ELECTRIC COMPANY
[redacted]

3. Product Mix

[redacted]

6 [redacted]

7 [redacted]

a. Product Mix Targets

[redacted]

[redacted]

[redacted]

---

8 [redacted]

[redacted]

TABLE E-3
PACIFIC GAS AND ELECTRIC COMPANY

[redacted]

[redacted]

[redacted]

[redacted]

9 [redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

4. Execution Strategy

[redacted]

---

10 [redacted]

[redacted]

[redacted]

FIGURE E-2
PACIFIC GAS AND ELECTRIC COMPANY
[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

D. Operating Outside of the Hedging Plan

1. Transition Plan

Because this Hedging Plan incorporates significant changes from PG&E's current Commission-approved hedging plan and because this Hedging Plan will be applied to PG&E's existing portfolio upon Commission approval, PG&E may not be able to immediately, upon Commission approval, implement this Hedging Plan and reach the [redacted]

[redacted]

[redacted]

2. Unusual Events, Market Dislocations, and Emergencies

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

E. Liquidity Management Strategy

[redacted]

1. Liquidity Management Structure

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

11 [redacted]

12 [redacted]

FIGURE E-3
PACIFIC GAS AND ELECTRIC COMPANY
LIQUIDITY MANAGEMENT STRUCTURE

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

2. Liquidity Measurement and Reporting

[redacted]

TABLE E-4
PACIFIC GAS AND ELECTRIC COMPANY
LIQUIDITY MANAGEMENT STRUCTURE

[redacted]

3. Liquidity Mitigation Strategies

[redacted]

- [redacted]
- [redacted]

APPENDIX F

NUCLEAR FUEL PROCUREMENT PLAN

A. Background on Nuclear Fuel Procurement

1. The Nuclear Fuel Cycle

Within the nuclear fuel cycle, there are four main segments of activity, which usually involves separate procurements for each segment. These segments are the purchase of uranium concentrates ("U3O8"), conversion services to convert the uranium to uranium hexafluoride gas ("UF6"), enrichment services to raise the concentration level of fissionable material in the uranium to meet Diablo Canyon Power Plant's ("DCPP") fuel cycle requirements, and fabrication of the actual fuel assemblies in the form required to be loaded into DCPP's reactors.

Pacific Gas and Electric Company ("PG&E") [redacted] There are approximately 15-20 uranium producers in the world with up to another 200 junior mining companies that currently engage in exploration and resource development.

Conversion services are provided worldwide by four commercial producers. These facilities convert the solid uranium concentrates into a gaseous solution, UF6, through a complex process of chemical reactions. UF6 is the feed stock for the enrichment segment of the process. [redacted]

The feed stock, UF6, is delivered to the enrichment facilities where the concentration of the fissionable isotope U235 is increased from natural background levels to the concentration required to fuel DCPP. The working unit for enrichment is called a Separative Work Unit ("SWU"), which is the measure of the amount of energy required to complete the concentration process. There are five commercial enrichment facilities in the world. [redacted]

EUP is the final product of the enrichment process and becomes the feed material to create fuel pellets that are loaded into the fuel assemblies during the fuel fabrication process. [redacted]

A typical reload of new fuel assemblies requires 1.1 million pounds ("lbs.") of uranium, 400,000 kilograms Uranium ("kgU") of conversion services and 270,000 SWU of enrichment services. The reload consists of between 84-92 fuel assemblies, roughly 45 percent of the reactor core.

2. Diablo Canyon Power Plant Operations Plan

[redacted]

[redacted]

[redacted]

TABLE F-1
PACIFIC GAS AND ELECTRIC COMPANY
DCPP ESTIMATED NUCLEAR FUEL SUPPLY REQUIREMENTS 2015-2024

[redacted]

B. PG&E's Nuclear Fuel Procurement Plan

[redacted]

[redacted]

1. Forward Contracting and Price Terms

[redacted] [1] [redacted]

[redacted]

---

1 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2. Nuclear Fuel Strategic Inventory Management

[redacted]

[redacted]

[redacted]

3. Proposed Risk Management Measures

[redacted]

- [redacted]
- [redacted]

4. Nuclear Liability and Insurance Issues Regarding Nuclear Fuel Contracts

[redacted]

[redacted]

[redacted]

5. Capped Liability Under Some Contracts

[redacted]

C. Issues Affecting the Plan

1. Regulatory and Political Outlook Not Specific to PG&E

[redacted]

[redacted]

[redacted]

2. Transactions Outside the Scope of the Plan

[redacted]

D. Summary of Proposal and Conclusion

PG&E has offered the following recommendations for prudent and cost-effective procurement of nuclear fuel materials and services during the period of 2015 through 2024:

- [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

PG&E's Nuclear Fuel Procurement Plan is intended to assure the security of fuel supply for the continued safe and efficient operation of the DCPP reactors, essential for power reliability in northern California, and will contribute to reduced operational nuclear fuel expenses. The plan includes upfront standards and criteria by which the acceptability and eligibility for rate recovery of proposed nuclear fuel procurement transactions will be known by PG&E prior to execution of the transactions.

APPENDIX G

GREENHOUSE GAS PROCUREMENT PLAN

A. Background

1. California Air Resource Board's Cap-and-Trade Regulations

Assembly Bill ("AB") 32 is California's groundbreaking Greenhouse Gas ("GHG") legislation that requires the reduction of statewide GHG emissions to 1990 levels by 2020. To this end, the California Air Resources Board ("CARB") proposed a statewide Cap-and-Trade regulation and other programmatic measures, including a Renewables Energy Standard, Customer Energy Efficiency, and Combined Heat and Power, to achieve these emissions reductions. The Cap-and-Trade regulation, which became effective on January 1, 2012, is intended to establish a market-based price for GHG emissions and, over time, provide market signals for efficient resource utilization and procurement activities to reduce GHG emissions.

Compliance with the emissions cap established in the CARB Cap-and-Trade regulation began in 2013 and is broken up into three compliance periods. The first compliance period—for the years 2013 through 2014—began on January 1, 2013. Covered entities in the first compliance period include operators of any facility that annually emits at least 25,000 metric tons of carbon dioxide equivalent ("mtCO_2e").[1] Operators are required to obtain and surrender compliance instruments equivalent to the annual GHG emissions for each such facility. Importers of electricity into California are also responsible for obtaining and retiring compliance instruments for GHG emissions deemed to be associated with electricity imports for purposes of compliance with Cap-and-Trade.

[1] Units of GHG are typically measured in terms of mtCO2e.

The second compliance period—for the years 2015 through 2017—is scheduled to commence on January 1, 2015. Beginning in the second compliance period, covered entities expand to include, among others, suppliers of natural gas that meet or exceed the 25,000 $mtCO_2e$ threshold. A supplier of natural gas is required to obtain and surrender compliance instruments for every metric ton of CO_2e that would result from the full combustion or oxidation of all fuel delivered to end users in California, less the emissions associated with fuel that is delivered to its customers that are required to participate in the Cap-and-Trade Program ("covered entities").

This plan only covers procurement activities necessary to comply with Pacific Gas and Electric Company's ("PG&E") obligations related to electric procurement. Additional procurement necessary to meet PG&E's compliance obligations as a natural gas supplier and the associated cost recovery will be as authorized through California Public Utilities Commission ("CPUC" or "Commission") Order Instituting Rulemaking ("R.") 14-03-003 or subsequent Commission proceedings.

There are two types of compliance instruments:

i. ***Allowances*** are limited tradable authorizations accepted by CARB to emit up to one $mtCO_2e$. Allowances are year-specific and can be used for an annual compliance filing for the year it was issued or for any subsequent compliance filing. An allowance can be bought, sold, transferred, or "banked" for use in a particular compliance period. Allowances are available via direct allocation[2] by CARB, auctions conducted under the

[2] According to the Cap-and-Trade regulation, the Investor-Owned Utilities ("IOU") are required to consign 100 percent of their Electric Distribution Utility ("EDU") directly allocated allowances to the auctions in the allocation year. An IOU cannot use a directly allocated EDU allowances to satisfy its compliance obligation.

auspices of CARB, and the Allowance Price Containment Reserve[3] ("APCR") established by CARB. CARB auctions are held quarterly. Allowances are also available in the market.

ii. ***Offset Credits*** ("Offsets") are tradable compliance instruments accepted by CARB that represent verified reductions of one $mtCO_2e$ from projects whose emissions or avoided emissions are not from a source covered under the Cap-and-Trade Program. For compliance purposes, an Offset and an allowance are virtually interchangeable for the year issued, however, an entity can only use Offsets to meet up to 8 percent of its compliance obligation in any compliance period. In addition, CARB's Cap-and-Trade regulation allows CARB to invalidate an Offset for errors, regulatory violations or fraud. CARB has adopted specific rules for using Offsets for Cap-and-Trade compliance, including the types of projects that qualify and the process for Offset verification, issuance, and registration.

Allowances and Offsets may also be available from external GHG Emissions Trading Systems to which California has linked.[4]

PG&E's actual Cap-and-Trade compliance obligation for a given year is determined by the GHG emissions reported annually to CARB per the Mandatory Reporting Rule.[5] Annual reports are due to CARB by April 10 of the calendar year following the emission year for facility operators or suppliers, and June 1 for electric power entities. Cap-and-Trade compliance showings are made annually and at the end of each compliance period. In order to demonstrate compliance in a given year, PG&E must surrender enough compliance instruments to cover 30 percent of its qualifying emissions by November 1 of the following calendar year (annual surrender date). In addition,

[3] The CARB APCR is populated with a finite quantity of allowances available for purchase at fixed prices and only by covered entities.

[4] CARB's Board-approved amendments allowing for the use of compliance instruments issued by linked jurisdictions on May 10, 2013. California is currently linked with Quebec.

[5] Regulation for the Mandatory Reporting of GHG Emissions (Division 3, Chapter 1, Subchapter 10, Article 2, Sections 95100-95133, title 17, California Code of Regulations).

PG&E must surrender enough compliance instruments to cover the balance of its qualifying emissions over a multi-year compliance period by November 1 of the calendar year following the end of each compliance period ("compliance period surrender date").

PG&E receives an allocation of free allowances associated with its business as an EDU directly from CARB annually; however, these free allowances cannot be used directly by PG&E to satisfy its compliance obligation.

All directly-allocated electric allowances must be consigned by PG&E into one or more of the auctions. In each year, allowances consigned at least 75 days prior to a quarterly auction will be offered for sale at that auction and each consigning entity agrees to accept the auction settlement price for allowances sold at auction. Until 2015, only IOUs and Publicly-Owned Utilities can consign allowances to the auction, and beginning in 2015, natural gas suppliers can also consign allowances into the auction.

2. Greenhouse Gas Compliance Instruments and CARB Auctions

A description of the authorized GHG compliance instruments is provided in Appendix A. A description of the CARB Auction and APCR process is provided in Appendix B of the Bundled Procurement Plan ("BPP").

B. PG&E's Allowance Consignment

[redacted]

6 [redacted]

C. PG&E's Potential Greenhouse Gas Risks

1. Greenhouse Gas Obligations

PG&E is required by CARB's Cap-and-Trade regulation to surrender compliance instruments for its qualifying Utility-Owned Generation ("UOG") and imports (collectively described as "physical" obligations). PG&E also has contractual obligations associated with certain tolling agreements that require it to either: (1) provide the counterparty with compliance instruments for the energy under contract; or (2) reimburse the counterparty for the Cap-and-Trade compliance costs associated with its facility's operation under the contract.

2. Cap-and-Trade Penalties

PG&E could face CARB penalties for failure to surrender an adequate number of compliance instruments for which it has a compliance obligation. CARB's Cap-and-Trade rule imposes a four-time excess emissions penalty resulting from "untimely surrender" of allowances. This penalty would be assessed by requiring that additional compliance instruments be surrendered, rather than by cash payment. In addition, if an entity fails to surrender the required compliance instruments within five days of the first auction or reserve sale conducted by CARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed, CARB's Cap-and-Trade rule would treat each ton of GHG emissions for which a compliance instrument was not surrendered as a separate violation for each day the violation continues.

3. Offset Credits

CARB's Cap-and-Trade regulation allows CARB to invalidate an Offset for errors, regulatory violations, or fraud. In the case where an Offset is used to meet a compliance requirement and is later invalidated, the complying entity must replace the invalidated Offset with a valid compliance instrument within six months of notification by CARB of the Offset's invalidation or be subject to compliance penalties. PG&E will only purchase Offsets if the purchase contract requires the seller to assume the risk of invalidation and to post appropriate collateral. PG&E will assess the risk of invalidation for each Offset transaction.

D. PG&E's GHG-Related Product Procurement

This GHG Procurement Plan addresses the GHG-related procurement authority necessary for PG&E to comply with the obligations associated with emissions from electricity sectors covered by Cap-and-Trade Program, namely facilities with GHG emissions greater than or equal to 25,000 $mtCO_2e$ per year and imported electricity. As an entity that is required to comply with Cap-and-Trade, PG&E will need to procure compliance instruments to meet the compliance requirements associated with its own facilities and imports, as well as the GHG contractual obligations associated with Power Purchase Agreements with third parties that require PG&E to procure GHG compliance products or assume GHG compliance costs for such parties. Below, PG&E describes its GHG obligations and GHG procurement strategy. As noted below, Commission-approved GHG-related products ("GHG Products"), procurement processes, and GHG Procurement Limits are provided in Appendices A, B and C, respectively, of this BPP. The products, procurement processes, GHG Procurement Limits, and GHG procurement strategy establish the upfront achievable standards for PG&E's procurement activities consistent with AB 57.

1. Greenhouse Gas Obligations

PG&E's primary need to procure GHG compliance instruments and engage in GHG transactions arises in connection with the following:

- Utility-Owned Facilities: Conventional generation facilities owned by PG&E that are either operating or under construction and that emit at least 25,000 $mtCO_2e$ per year, such as the Humboldt Generating Station, Colusa Generating Station, and Gateway Generating Station, will have a compliance obligation under Cap-and-Trade.
- Certain Tolling Agreements: Contracts that allocate to PG&E or where PG&E has assumed GHG compliance instrument procurement responsibility for such counterparties.
- Electricity Imports: PG&E is responsible for GHG emissions deemed to be associated with its electricity imports for purposes of compliance with Cap-and-Trade.

2. Greenhouse Gas-Related Products

GHG Products approved by the Commission are listed in Appendix A.

3. Greenhouse Gas-Related Processes

PG&E will procure GHG Products using the procurement methods and processes in accordance with Appendix B.

4. Greenhouse Gas Procurement Strategy

PG&E will procure sufficient GHG Products during each compliance period to meet its GHG obligations. PG&E's procurement strategy includes the following key elements:

[redacted]

[redacted]

i. GHG Procurement Limits

Each of these elements is described in more detail below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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7 [redacted]

8 [redacted]

9 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

10 [redacted]

11 [redacted]

[redacted]

12 [redacted]

13 [redacted]

14 [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

i. GHG Procurement Limits

GHG Procurement limits are provided in Appendix C.

5. Procurement Review Group Consultation

PG&E's consultation with the PRG is addressed in Appendix M.

6. Cost Recovery

Cost recovery of GHG Products is discussed in Section IV.F of the BPP

7. Approval for Contract Term Duration

CPUC approval of transactions is discussed in Section V of the BPP

8. Independent Evaluator

Independent Evaluator requirements are discussed in Appendix M.

[redacted]

[redacted]

[redacted]

APPENDIX H

CONVERGENCE BIDDING

A. Background

Since April 2009, the California Independent System Operator ("CAISO") has managed a Day-Ahead Market ("DAM") and provided for Locational Marginal Pricing ("LMP"). Through its market processes, the CAISO produces LMPs for the DAM (i.e., one day prior to the flow of power) and the Real-Time Markets ("RTM") (i.e., up to one hundred and thirty five minutes prior to the flow of power). Since May 2014, the RTM has consisted of both Fifteen-Minute (new) and Five-Minute Markets.

Convergence bids are financial transactions (i.e., virtual bids for energy that will not be consumed or produced), that can only be submitted in the DAM, and are recognized by system operators as not being physical. Convergence bids represent a financial commitment to sell (or buy) energy in the DAM at the individual pricing node location where the convergence bid is submitted. If these bids are cleared in the DAM, they are automatically liquidated by the CAISO with an opposite buy-back by seller or sell-back by buyer of the same quantity of energy in the Fifteen-Minute Market.

The CAISO initiated convergence bidding on February 1, 2011.

B. CPUC Authorization

On December 21, 2010, the California Public Utilities Commission ("CPUC" or "Commission") issued Decision 10-12-034 authorizing the investor-owned utilities ("IOU") to participate in convergence bidding under three separate strategies. The decision provided interim authority until a subsequent decision superseded or modified the authority granted, or a stop-loss limit[1] was reached. The decision further established that the IOUs are not required to use any or all of the three bidding strategies and may apply them flexibly to meet their own circumstances. Decision 10-12-034 was subsequently modified by Decision 11-06-004.

C. PG&E's Convergence Bidding Participation

Pacific Gas and Electric Company ("PG&E") may use one or more of the following convergence bidding strategies authorized by the Commission:

- **Strategy 1 –** Generation performance risk and load forecast uncertainty hedging. PG&E is authorized to participate in convergence bidding to manage Real-Time price exposure resulting from unanticipated forced outages, derating of generating units, derating of transmission, or uncertain generation performance for resources scheduled by PG&E in the CAISO's DAM. This strategy also authorized submission of bids related to long-start generation units.[2]

- **Strategy 2 –** Intermittent resource schedule and hedging. PG&E is authorized to submit virtual supply bids in the CAISO's DAM up to, but not exceeding, the amount of the Day-Ahead forecast of intermittent generation in the Day-Ahead Market, followed by buying it back through the convergence sale in the CAISO RTM.

- **Strategy 3 –** Defensive bidding against market dynamics. PG&E is authorized to participate in defensive convergence bidding in the CAISO's Day-Ahead and Real-Time energy markets to mitigate real harms from market manipulation or other unintended market dynamics. Any IOU using defensive convergence bidding must report such use on a case-by-case basis with actual market and settlement data, and not just hypothetical scenarios showing how engaging in convergence bidding by the IOUs protected ratepayers. Each IOU must report if and how it employed convergence bidding strategies intended to

[1] A 365-day rolling stop net-loss limit of $20 million for PG&E and Southern California Edison Company, and $5 million for San Diego Gas & Electric Company, that requires suspension of convergence bidding pending IOU explanation and CPUC re-authorization.

[2] D.11-06-004, OP 1.

protect the IOU's ratepayers from avoidable risks at identified locations. This information will be used for future review of convergence bidding authority and not for post-hoc reasonableness reviews of utility bidding activities.

PG&E's convergence bidding under all strategies will be restricted to the nodes or locations where PG&E-owned or contracted resources or loads are physically located, at interties where utility resources or loads are located, as well as at the previously authorized nodes or locations.[3]

D. Utility Convergence Bidding Reporting

PG&E will provide quarterly convergence bidding reports to the CPUC's Energy Division ("ED"). The reports will include:

1) For that month, a list of each cleared convergence bid, containing the hour, location, volume, and justification for the transaction.

2) A list of the Day-Ahead and relevant Hour-Ahead Scheduling Process or Real-Time prices corresponding with each convergence bid during the month.

3) For each day during the month, the gains or losses, in dollars, as a result of convergence bidding.

4) For that month, and any past months during the calendar year in which convergence bids were transacted, a monthly total of volume, gains or losses (in dollars), the number of times (by hourly bid) each strategy was employed, and the number of bids conducted outside of PG&E's service territory.

5) The approved convergence bidding strategies utilized during that time period.

6) Qualitative analysis of convergence bidding impacts upon other related products, such as Congestion Revenue Rights during the period.

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[3] *Id.*

7) A list of any PG&E affiliates who have or are registered with the CAISO to participate in convergence bidding.

The quarterly reporting will be included as part of the Quarterly Compliance Report filings. PG&E will also consult quarterly with the Procurement Review Group ("PRG") to provide a review of PG&E's convergence bidding strategies, performance and market analysis.

E. Stop Net-Loss

PG&E will monitor the net profit and losses associated with submittal of convergence bids. In the event that the 365-day rolling net-loss exceeds or is expected to exceed $20 million, PG&E will cease implementation of all convergence bidding strategies and confer with the PRG. To the extent that PG&E determines that continuation of convergence bidding is warranted, it will file a Tier 3 Advice Letter ("AL") with the Commission. The AL must contain, at a minimum: (1) an explanation for why PG&E exceeded the stop-loss limit; (2) an explanation of what actions or changes to its bidding activity PG&E will implement to ensure that future convergence bidding will not continue to lose ratepayer funds; and (3) an explanation for why PG&E's authority to engage in convergence bidding should be reinstated, in light of the specific facts of PG&E's convergence bidding history and remedial activities to protect ratepayer funds. Unless and until the Commission approves the AL with or without conditions, PG&E shall have no authority to engage in convergence bidding regardless of how long the Commission takes to issue a ruling on the AL.

F. California Independent System Operator Notification Requirements

PG&E shall, within one (1) business day of its receipt of notice, provide written notice to the CPUC's Executive Director, the Director of Energy Division and the General Counsel of: (1) notice from the CAISO or its Department of Market Monitoring that PG&E or its scheduling coordinator is the subject of an investigation pursuant to the CAISO Tariff, including Section 37.8.4; (2) notice from the CAISO that the conduct of PG&E or its scheduling coordinator's conduct has been referred to the Federal Energy Regulatory Commission by the CAISO pursuant to the CAISO Tariff, including Section 37.8.2; or (3) notice from the CAISO that PG&E or its scheduling coordinator's convergence bidding trading has been suspended or limited by the CAISO.

G. Future Convergence Bidding Strategies

PG&E may seek authority through a Tier 3 AL filing to participate in additional convergence bidding areas and/or propose additional convergence bidding strategies.

APPENDIX I

CONGESTION REVENUE RIGHTS

A. Introduction

Pacific Gas and Electric Company ("PG&E") is authorized to procure Congestion Revenue Rights ("CRR") under two California Public Utilities Commission ("CPUC" or "Commission") resolutions. CRRs are financial instruments issued by the California Independent System Operator ("CAISO"). Resolution E-4135 authorized PG&E to procure CRRs in the CAISO's monthly and annual processes. Resolution E-4122 authorized PG&E to procure Long-Term Congestion Revenue Rights ("LT-CRR") in the CAISO's long-term process. Both resolutions authorized PG&E to purchase and sell CRRs in the secondary markets.

The monthly and annual CRR processes consist of up to three allocation tiers and an auction. In the allocation tiers, only Load Serving Entities ("LSE") such as PG&E can nominate CRRs that they wish to obtain at no direct cost. LSEs can procure CRRs up to an amount determined by their historical or forecasted load. In the auctions, which are open to all market participants, PG&E can purchase or sell CRRs at market-based prices determined through the competitive auction. The Annual CRR process releases CRRs with calendar quarter delivery periods that occur over the next year. The monthly CRR process releases CRRs with monthly delivery periods for the next month.

The LT-CRR process consists of one allocation tier each year and is performed as part of the annual CRR process. In this Long Term Tier, quarterly-term CRRs previously acquired from the annual Tier 1 allocation can be nominated for conversion to LT-CRRs with same quarter deliveries for the subsequent nine years.

B. Congestion Revenue Rights and Long-Term Congestion Revenue Rights Procurement Objectives

As the Commission determined in Resolutions E-4135 and E-4122, PG&E uses CRRs and LT-CRRs to hedge against expected congestion costs. PG&E does not use CRRs and LT-CRRs for financial speculation.

C. Congestion Revenue Rights Procurement

1. Congestion Revenue Rights Source-Sink Pairs and Paths

PG&E is authorized to acquire CRRs and LT-CRRs for any path (represented by a source-sink pair) connecting existing generation sources to existing loads (retail loads, Helms pumping load, and wholesale load obligations) or for any path that PG&E reasonably anticipates it might need to flow energy in the future due to the addition of new contracts, resources, or load obligations. Additionally, there may be CRRs or LT-CRRs which are positively correlated in value with CRRs or LT-CRRs for paths that have limited availability. PG&E is authorized to acquire CRRs and LT-CRRs for such positively correlated paths as well. Therefore, PG&E will obtain any CRRs and LT-CRRs that are determined to be valuable as hedges against congestion costs at the time they are offered, subject to selection criteria regarding the specific source/sink combinations as described in Section E of this Appendix.

2. Procurement Review Group Consultation

PG&E consults with its Procurement Review Group (“PRG”) regarding CRRs and LT-CRRs. PRG consultation is described in more detail in Appendix M.

D. Volume Limits

PG&E's CRR and LT-CRR procurement is subject to source-specific volume limits. That is, PG&E will limit the "net" volume[1] that it could procure at each source node to the maximum non-coincident capacity of the sources (existing, potential, planned, or "positively correlated") at that node for that delivery period. There are separate source-specific volume limits for the on-peak and off-peak hours in the delivery period. Overall or total CRR volume limits are unnecessary because PG&E is already limited by CAISO rules, and to hedging no more than its total expected or anticipated grid use.

E. Selection Criteria for Congestion Revenue Rights in Allocation and Auction Processes

[redacted]

- [redacted]
- [redacted]

[redacted]

[1] "Net" volume refers to the result of netting CRRs in one direction with CRRs in the counter-flow direction.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

F. Congestion Revenue Rights Auction Participation

[redacted]

2 [redacted]

[redacted]

- [redacted]

[redacted]

[redacted]

G. Transactions in Secondary Congestion Revenue Rights Market

[redacted]

APPENDIX J

BROKERAGES AND EXCHANGES

A. Brokerages[1]

- Tullett Prebon Financial Services LLC
- ICAP United, Inc.
- TFS Energy Futures, LLC
- Amerex Brokers LLC
- Landmark
- Saddleback
- Anahau Energy LLC (a Women, Minority, or Disabled Veteran-Owned Business Enterprises ("WMDVBE"))
- Evolution Markets Inc.
- Bluesource Energy, LLC (WMDVBE)
- Energy Trade Management GP, LLC
- Equus Energy Group, LLC
- Marex Spectron
- Karbone Inc.
- BGC Environmental Brokerage Services, L.P.
- Edge Energy, LLC
- EOX Holdings LLC (includes Choice Energy!, L.P. and Choice Natural Gas)
- Clear Energy Brokerage & Consulting, LLC
- The Finerty Group, Inc. (WMDVBE)
- Sterling Planet, Inc.

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[1] PG&E can only procure greenhouse gas ("GHG") products via brokers through a Request for Offers. *See* Decision ("D.") 12-04-046, Ordering Paragraph ("OP") 8.g.

B. Exchanges[2] and Futures Commission Merchants

- Intercontinental Exchange (“ICE”) – Exchange and Cleared (Clear Europe) trades
- New York Mercantile Exchange (“NYMEX”) – Exchange and Cleared (NYMEX, NYMEX Clearing, GreenX/CME Clearing) trades
- Natural Gas Exchange (“NGX”) – Physical and Financially Cleared Gas Products
- Barclays Capital Inc. (allows accessibility to NYMEX, NYMEX Clearing, and ICE Clear Europe)
- J.P. Morgan Futures, Inc. (allows accessibility to NYMEX, NYMEX Clearing, ICE Clear Europe, and GreenX/CME Clearing)
- Mizuho Securities, USA (allows accessibility to NYMEX, NYMEX Clearing, ICE Clear Europe, and GreenX/CME Clearing)
- Wells Fargo Advisors, LLC (allows accessibility to NYMEX, NYMEX Clearing, and ICE Clear Europe)
- BNP Paribas Prime Brokerage Inc. (allows accessibility to ICE Clear Europe and GreenX/CME Clearing)
- ICAP Energy, LLC – the ICAPture Electronic Trading Platform (online energy derivative trading)
- Macquarie Futures USA, LLC (allows accessibility to NYMEX, NYMEX Clearing, ICE Clear Europe)

C. GHG Product Authorized Exchanges

- ICE – Exchange and Cleared (Clear Europe) trades

[2] PG&E can procure GHG products on exchanges that were approved by the California Public Utilities Commission (“CPUC” or “Commission”) for power procurement before D.12-04-046 was issued. For exchanges not previously approved, PG&E must submit a Tier 2 advice letter detailing: (1) what exchange it is seeking to use; (2) the liquidity and transparency of the exchange, specific to GHG Products, including an explanation of how the Commission can be assured that the prince of the products procured on the exchange is reasonable; and (3) the regulatory authority or authorities the exchange is subject to. *Id*., OP 8.h. Exchanges approved for GHG products are identified in Section C below.

- NYMEX – Exchange and Cleared (NYMEX, NYMEX Clearing, GreenX/CME Clearing) trades
- NGX – Physical and Financially Cleared Gas Products
- Barclays Capital Inc. (allows accessibility to NYMEX, NYMEX Clearing, and ICE Clear Europe)
- J.P. Morgan Futures, Inc. (allows accessibility to NYMEX, NYMEX Clearing, ICE Clear Europe, and GreenX/CME Clearing)
- Mizuho Securities, USA (allows accessibility to NYMEX, NYMEX Clearing, ICE Clear Europe, and GreenX/CME Clearing)
- Wells Fargo Advisors, LLC (allows accessibility to NYMEX, NYMEX Clearing, and ICE Clear Europe)
- BNP Paribas Prime Brokerage Inc. (allows accessibility to ICE Clear Europe and GreenX/CME Clearing)
- ICAP Energy, LLC – the ICAPture Electronic Trading Platform (online energy derivative trading)

APPENDIX K

BIDDING AND SCHEDULING PROTOCOLS

A. Introduction

The California Public Utilities Commission ("Commission" or "CPUC") has adopted Standards of Conduct ("SOC") for procurement-related activities, including SOC 4 which provides that the utilities should dispatch their generation resources in a least-cost manner. The Commission has recently recognized that with the California Independent System Operator's ("CAISO") implementation of its Market Redesign and Technology Upgrade ("MRTU"), "[t]he regulated energy utility is responsible for scheduling and bidding its generation to the CAISO, but once that is done, it is the CAISO's responsibility to dispatch the generation."[1] This Appendix describes Pacific Gas and Electric Company's ("PG&E") scheduling and bidding practices for the resources in its bundled portfolio. For purposes of this Appendix, the scheduling and bidding process is also referred to as Least-Cost Dispatch or "LCD."

Section B below provides an overview of the CAISO markets. In Section C, PG&E describes its scheduling and bidding principles that help PG&E achieve LCD, and Section D describes the specific scheduling and bidding processes used by PG&E.

B. Overview of CAISO Markets

1. Day-Ahead Markets

The CAISO's Day-Ahead Market ("DAM") provides market participants with the opportunity to contract financially for the buying and selling of energy for the following day. The DAM includes Market Power Mitigation-Reliability Requirement Determination, the Integrated Forward Market ("IFM") and the Residual Unit

[1] Decision 14-05-023, Finding of Fact 15.

Commitment. In the IFM, the CAISO clears financially binding offers to buy and sell energy based on the physical characteristics and locations of available resources and customer loads, for each of the 24 hours of the following day. The CAISO also uses the IFM to perform its own procurement of Ancillary Services ("A/S") (regulation up, regulation down, spinning reserve and non-spinning reserve) to ensure system reliability for the next day. Market clearing and A/S procurement are performed "optimally" (so far as current technologies allow) using a security constrained unit commitment algorithm which minimizes total costs based on submitted bids, the CAISO's A/S requirements, and the constraints on power flows imposed by the control area's large and complex transmission network.

Because the IFM is financially rather than physically binding for most energy schedules (the exceptions are long start instructions and any energy associated with the binding procurement of A/S by the CAISO), the CAISO performs a "post processing" Residual Unit Commitment phase in the DAMs to ensure that sufficient capacity is available in the Real-Time Markets ("RTM") to meet the CAISO's own forecast of control area load.

2. Real-Time Markets

The CAISO executes several overlapping market processes that together are categorized as "real-time" because they are physically binding at the time of delivery. Only two of these processes, the Fifteen Minute Market ("FMM") and the Real-Time Economic Dispatch ("RTED") market process, result in prices that are used for energy and A/S settlements. The FMM market utilizes the Real-Time Unit Commitment

("RTUC") process every 15 minutes to determine binding unit commitments and A/S awards and financially binding energy awards, along with locational market prices. The RTED runs every five minutes and determines binding dispatch instructions along with locational market prices. Two other processes, the Short-Term Unit Commitment and the Hour Ahead Scheduling Process, result in commitments or preschedules of resources that can be started, shut down, or prescheduled in their respective timeframes but do not result in binding energy schedules or clearing prices. Finally, Local Market Power Mitigation ("LMPM") runs during each run of RTUC to mitigate bids used in the RTUC and RTED processes for a given hour.[2]

Between the day-ahead and hour ahead market timeframes, changes in system conditions, weather, transmission, and resource availability, are inevitable. PG&E resources with the flexibility to increase and decrease generation in response to changes in load and operating requirements are bid into both the day-ahead and real-time markets.

C. Scheduling and Bidding Principles

PG&E has adopted the following principles to guide its scheduling and bidding activities:

- PG&E aims to minimize its total cost of energy required to meet load and A/S requirements, subject to regulatory, legal, operational, contractual, and financial requirements.
- PG&E's scheduling and bidding process considers all regulatory, legal, operational, contractual and financial requirements.

[2] The LMPM process produces no binding energy schedules or clearing prices itself, though the resulting mitigated bids may affect energy schedules and clearing prices in the FMM and RTM market processes that follow LMPM.

- PG&E minimizes energy costs by explicitly considering the incremental costs of all resources available to it in scheduling or bidding decisions.
- PG&E integrates any local area reliability, day-ahead scheduling requirements, and deliverability requirements into its scheduling or bidding decisions.
- The CAISO markets perform LCD for all resources bid/scheduled into the markets based on information provided by all market participants, transmission information that is solely available to the CAISO, and information regarding system conditions that are solely available to the CAISO.
- The parameters and forecasts that PG&E has ability to control with regard to LCD are the following: load forecast, market price forecast, incremental heat rate, and master file submission. These parameters and forecasts are used in the calculation of submitted bids and/or schedules.
- LCD activities are subject to forecast and market uncertainties, including those associated with actual customer loads, behavior of other market participants, actual energy deliveries from Qualifying Facilities and intermittent resources, non-public transmission constraints, and CAISO reliability-based discretionary decisions.

The principles described above remain essential for achieving LCD and meeting all the regulatory, legal, operational, contractual and financial requirements associated with PG&E's portfolio. These principles inform the specific scheduling and bidding processes described below in Section D.

D. Scheduling/Bidding Processes

All resources are scheduled or bid into the CAISO markets based on their incremental cost/opportunity cost, or self-scheduled based on constraints that limit their ability to be bid. The fundamental principle of LCD is to ensure that PG&E's dispatchable resources are used when their incremental costs or opportunity costs are below the cost of energy in the CAISO wholesale markets. By appropriately scheduling and bidding its resources into the CAISO markets at their incremental or opportunity costs, PG&E ensures that total procurement to meet customer demand in the CAISO markets is at least cost.

1. Incremental Costs

PG&E schedules or bids resources into the CAISO markets at incremental cost of providing energy, considering both the variable operating cost of its resources and the market cost of generation. Fixed costs that cannot be affected by how resources are dispatched, such as capital investment costs or contract capacity payments, are treated as sunk and hence not incremental. Resource costs that can either be increased or decreased depending on how the resource runs are properly treated as incremental costs.

Day-ahead dispatch considers incremental costs incurred hourly and incremental costs incurred when resources (or components of resources) are started up or "committed." Hourly incremental costs include fuel costs and variable operations and maintenance ("O&M") costs that vary directly with desired energy output, as well as the "minimum load" cost of keeping a resource online at its minimum operating level per hour. Incremental costs of commitment recognized by the CAISO in its Master File are characterized as "startup", and for Multi-Stage Generation resources, "state transition" costs. Minimum load, startup and transition costs include fuel costs as well as variable O&M costs. In addition, if the costs of inspections and overhauls are increased when units run for more hours or cycle more, these maintenance costs are also treated as variable costs in LCD. The CAISO enables gas fired resources to submit to its markets minimum load and startup cost parameters either as "proxy" costs or "registered" costs.

Proxy costs are calculated daily by the CAISO as the product of a heat rate times a fuel cost index plus variable O&M costs. Registered costs are a single dollar value for no less than 30 days at a time, and reflect a facility's fuel and non-fuel costs including longer term maintenance costs that vary with number of starts or number of hours running at minimum load. Registered costs are capped at a multiple of the CAISO calculation of proxy costs, performed when cost changes are submitted to the CAISO Master File.

The CAISO's optimization of each of its markets results in supply clearing against demand based on hourly bids and the costs of getting energy from supply nodes to demand nodes in the CAISO grid. Market prices are then determined on an hourly basis, the cost of energy at each location in the CAISO grid.

a. Greenhouse Gas

The Greenhouse Gas ("GHG") compliance obligation for the Cap and Trade Program is regulated by the California Air Resources Board. Any resource that emits greater than 25,000 metric tons of carbon dioxide equivalent ("$mtCO_2e$") is required to surrender allowances for its emissions. An allowance is a tradable permit to emit one $mtCO_2e$ GHG emission. These allowances are traded in the carbon market. To account for the cost of complying with the Cap and Trade Program, PG&E includes a GHG adder in the bid for any resource that has emitted on an annual basis greater than 25,000 $mtCO_2e$. The daily GHG price is based on a forward curve, which is based on index and broker quotes. PG&E may change the methodology due to, but not limited to, market, regulatory, or legal changes that impact the Cap and Trade Program and/or GHG compliance.

2. Opportunity Cost

Resources with no explicit fuel cost, such as hydroelectric plants, are bid at their opportunity costs, which are equivalent to fuel costs in their effect on total expected cost to customers. Each hydroelectric plant or watershed is subject to complex operating constraints, including Federal Energy Regulatory Commission license requirements and safety constraints, as well as to the fundamental limits on their energy outputs that result from limited natural inflows into reservoirs. Opportunity costs take into consideration the future value of energy, or equivalently for hydro resources the future value of water, and the fact that the amount of available water is limited. As such, it may be more prudent and lower cost to defer hydro generation to higher value future periods rather than using it in the current day at below its opportunity cost.

Similarly, economic bidding of eligible renewable contracts captures the opportunity costs associated with contractual, regulatory, and operational constraints. This also includes the incremental cost of any compliance instruments required to comply with the 33 percent Renewables Portfolio Standard (“RPS”) legislation. More detail regarding the incremental cost of RPS compliance instruments is included in confidential Attachment 1 to this Appendix K.

3. Self-Scheduling

Self schedules are interpreted by the CAISO markets as price taking supply or demand. Price taking supply is supply that is willing to accept any price to inject energy into the grid. In other words, self-scheduled supply is willing to accept any price to generate. Price taking demand self schedules, which can only be submitted by Load

Serving Entities in the DAM, indicate a willingness to pay any price to clear demand in that market.

PG&E self schedules some load in the DAM, and some supply in both the DAMs and RTMs, but minimizes the risks and costs of doing so by offering as much flexibility from its supply and demand portfolio as possible.

Some of PG&E's supply portfolio is must-take, either due to safety, environmental and license constraints, contract terms, regulatory requirements or because it is inherently nondispatchable (for example, run of river hydro with no reservoir controls). PG&E self schedules must-take supply in the DAM and then modifies these self schedules in real-time if the forecast of generation has changed.

APPENDIX K

ATTACHMENT 1

CONFIDENTIAL

REDACTED IN ITS ENTIRETY

UNDER PROTECTIONS OF D.06-06-066

AND

CALIFORNIA PUBLIC UTILITIES CODE

SECTIONS 454.5(G) AND 583

APPENDIX L

CAISO OPERATING ORDER PROTOCOLS

A. Introduction

The California Independent System Operator ("CAISO") has the responsibility to maintain the reliability and stability of the electric grid for its Balancing Authority Area.[1] As CAISO market participants, Pacific Gas and Electric Company ("PG&E") must conform to CAISO Tariff requirements. When events occur that may adversely impact system reliability, the CAISO may declare one of the following events: System Emergency, Congestion, or Overgeneration. As a Scheduling Coordinator ("SC") for generation resources in its portfolio, PG&E must manage its portfolio to respond to these CAISO-declared events. This Appendix describes PG&E's protocols for managing its portfolio during CAISO-declared events by implementing schedule changes and exercising contractual bidding and curtailment rights in response to CAISO-declared System Emergencies, Congestion, or Overgeneration. These protocols do not amend or modify the responsibilities or terms and conditions of existing agreements between PG&E and its contracted resources.

PG&E utilizes these protocols to help enable effective and timely action to respond to these events as the SC for numerous generation resources. Conditions or situations may arise that impact PG&E's ability to implement all of the identified actions described in this Appendix. In the event that PG&E receives an Operating Order from the CAISO, PG&E will seek to respond to the Operating Order by using reasonable efforts, subject to safety, operational and time limitations, to implement the protocols identified in this Appendix.

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[1] Capitalized terms in this Appendix have the same meaning as the defined term in the CAISO Tariff unless otherwise defined in this Appendix.

For purposes of this Appendix, the term “CAISO Operating Orders” is defined as operating orders that must be complied with, as described in Section 37.2.1.1 of the CAISO Tariff which provides:

> Market Participants must comply with operating orders issued by the CAISO as authorized under the CAISO Tariff. For purposes of enforcement under this Section 37.2, an operating order shall be an order(s) from the CAISO directing a Market Participant to undertake, a single, clearly specified action (e.g., the operation of a specific device, or change in status of a particular Generating Unit) that is intended by the ISO to resolve a specific operating condition. Deviation from an ADS Dispatch Instruction shall not constitute a violation of this Section 37.2.1.1. A Market Participant’s failure to obey an operating order containing multiple instructions to address a specific operating condition will result in a single violation of Section 37.2. If some limitation prevents the Market Participant from fulfilling the action requested by the CAISO then the Market Participant must promptly and directly communicate the nature of any such limitation to the CAISO.[2]

B. PG&E Protocols During CAISO-Declared System Emergencies

1. CAISO Description of System Emergency

The CAISO Tariff defines a System Emergency as:

> Conditions beyond the normal control of the CAISO that affect the ability of the CAISO Balancing Authority Area to function normally, including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading Outages or to restore system operation to meet Applicable Reliability Criteria.

For all System Emergencies, the CAISO is responsible for managing the emergency and restoration of the system as specified in the CAISO Tariff. The CAISO Tariff provides that “[a]ll Generating Units and System Units that are owned or controlled by a Participating Generator are (without limitation to the CAISO’s other rights under this

[2] Based on the CAISO Combined and Conformed Tariff as of September 2, 2014.

CAISO Tariff) subject to control by the CAISO during a System Emergency and in circumstances in which the CAISO considers that a System Emergency is imminent or threatened." Under Section 7 of the CAISO Tariff, the CAISO has the authority to "instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the CAISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency."

2. PG&E Protocols for Response

PG&E will communicate CAISO Operating Orders regarding System Emergencies to affected Generators for which PG&E is the SC, subject to the protocols for specific resources described in Section B.3 below.

3. Qualifying Facilities With Existing QF Contracts

Qualifying Facilities ("QF") with an Existing QF Contract are not required to execute a Participating Generator Agreement ("PGA") with the CAISO. CAISO Tariff Section 7.7.2.3 states: "Each QF subject to an Existing QF Contract and not subject to a PGA or Net Scheduled PGA will make reasonable efforts to comply with the CAISO's instructions during a System Emergency without penalty for failure to do so." However, for QFs with Existing QF Contracts which contain provisions that require the QF to interrupt or reduce deliveries during an emergency or in compliance with prudent electrical practices, PG&E will direct that such QF interrupt or reduce deliveries based on

CAISO Operating Orders. For QFs with Existing QF Contracts that do not contain provisions that require the QF to interrupt or reduce deliveries during an emergency or in compliance with prudent electrical practices, PG&E will convey CAISO Operating Orders that the QF interrupt or reduce deliveries based on CAISO Operating Orders. If a QF resource with an Existing QF Contract indicates to PG&E that it will not comply with CAISO Operating Orders during a System Emergency, PG&E will notify CAISO Generation Dispatch so that the CAISO can take appropriate, additional measures.

C. PG&E Protocols During CAISO-Declared Physical Congestion

1. CAISO Description of Physical Congestion

The CAISO Tariff defines Congestion as:

> A characteristic of the transmission system produced by a binding Transmission Constraint to the optimum economic dispatch to meet Demand such that the LMP, exclusive of Marginal Cost of Losses, at different Locations of the transmission system is not equal.

Congestion on the CAISO-controlled grid occurs whenever the preferred generation/demand schedule requires the provision of transmission services beyond the physical capability of the transmission system. In such a case, the preferred schedule cannot be accommodated without violating the physical limits of the transmission system. Congestion management is one of the major tasks performed by the CAISO to ensure the operation of the transmission system does not violate operating limits.

The CAISO may manage or address Congestion in the form of an issuance of the following Operating Orders:

- **Exceptional Dispatches –** Certain circumstance as described in CAISO Tariff Section 34.11, which may require derates, forced Shut-Downs, forced Start-Ups, or forced Multi-Stage Generation ("MSG") Transitions.
- **Return to Schedule –** A CAISO Operating Order to generate to a Schedule defined as the current Dispatch Operating Target through the Automated Dispatch System ("ADS") or CAISO's last verbal instruction.
- **Mandatory Reductions –** A CAISO Operating Order to reduce generation.

2. PG&E Protocols for Response

PG&E will communicate CAISO Operating Orders in the Day-Ahead or Real-Time regarding Congestion to affected Generators for which PG&E is the SC, subject to the protocols for specific resources described in Sections C.3 and C.4 below. Section C.5 below addresses how PG&E will respond to CAISO Operating Orders that direct *pro rata* generation reductions to address Congestion.

3. Qualifying Facilities With Existing QF Contracts

If the CAISO issues a Congestion-related Operating Order to PG&E for a specific QF Unit that has an Existing QF Contract and does not have a PGA, PG&E will communicate the CAISO Operating Order to the affected QF for which PG&E is the SC. If the QF resource indicates to PG&E that the QF will not comply with a CAISO Operating Order during a Congestion situation, PG&E will notify CAISO Generation Dispatch so that the CAISO can take appropriate, additional measures.

4. Nuclear

Diablo Canyon Power Plant ("DCPP") Units 1 and 2 will respond to CAISO Congestion-Related Operating Orders consistent with the DCPP Protocols.[3]

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[3] A copy of the Short-Term Electric Supply DCPP Non-Emergency Curtailment Protocols ("DCPP Protocols") is attached to this Appendix as Confidential Attachment 1.

5. *Pro Rata* Generation Reductions

During Congestion, the CAISO may issue an Operating Order in the Day-Ahead or Real-Time for a reduction of generation among several identified Units, without specifying the distribution of the reduction amongst the Units. PG&E will seek to manage such Operating Order by using reasonable efforts considering safety, operational, contractual and time limitations to implement the following:

- [redacted]
- [redacted]

D. PG&E Protocols During CAISO-Declared Overgeneration

1. CAISO Description of Overgeneration

The CAISO Tariff defines Overgeneration as:

> A condition that occurs when total Supply exceeds total Demand in the CAISO Balancing Authority Area.

Each Balancing Authority Area has a commitment to control its generation in a manner so as not to burden interconnected systems. CAISO personnel are responsible for identifying and managing Overgeneration conditions and forecasting the extent of the anticipated Overgeneration. The CAISO has adopted an Operating Procedure (i.e., Operating Procedure 2390) to address CAISO systemwide Overgeneration. Local Overgeneration events are possible when there is excess generation in a localized area or set of areas, (e.g., ZP-26) which has the potential to result in stability issues or constrained operations.

In the Day-Ahead Market ("DAM"), the CAISO may announce a potential for Overgeneration prior to the DAM or after the DAM results have been published. This announcement is intended to encourage Market Participants to submit additional decremental ("DEC") bids for energy into the DAM and/or Real-Time Market ("RTM") and to provide an early alert that system conditions may warrant the use of the CAISO's Overgeneration Procedure.

CAISO operators may run out of market solutions and resort to out-of-market solutions and order Units to curtail generation.

The CAISO may manage or address Overgeneration out-of-market in the form of the following CAISO Operating Orders:

- **Exceptional Dispatches** – Certain circumstance as described in CAISO Tariff Section 34.11, which may require derates, forced Shut-Downs, or forced MSG Transitions.
- **Return to Schedule** – A CAISO Operating Order to generate to a Schedule defined as the current Dispatch Operating Target through the ADS or the CAISO's last verbal instruction.
- **Mandatory Reductions** – A CAISO Operating Order to reduce the generation.

2. PG&E Protocols in Response

PG&E's Day-Ahead and Real-Time responses to Overgeneration are described below in Sections D.3 and D.4. PG&E will communicate CAISO Operating Orders regarding Overgeneration to affected Generators for which PG&E is the SC, subject to the protocols for specific resources described in Sections D.5 and D.6 below. Section D.7 below addresses how PG&E will respond to CAISO Operating Orders that direct *pro rata* generation reductions.

3. Day-Ahead Response

[redacted]

4. Real-Time Response

If the CAISO announces Overgeneration in Real-Time and requests out-of-market offers to reduce output, PG&E will offer out-of-market dispatch (i.e., Exceptional Dispatch) from the following sources:

- [redacted]
- [redacted]
- [redacted]

4 [redacted]

5. Qualifying Facilities With Existing QF Contracts

If the CAISO issues an Overgeneration-related Operating Order to PG&E for a specific QF Unit that has an Existing QF Contract and does not have a PGA, PG&E will communicate the CAISO Operating Order to the affected QF for which PG&E is the SC. If the QF resource indicates to PG&E that the QF will not comply with a CAISO Operating Order during an Overgeneration situation, PG&E will notify CAISO Generation Dispatch so that the CAISO can take appropriate, additional measures.

6. Nuclear

Based on DAM results, DCPP Units 1 and 2 will be evaluated for potential schedule adjustments consistent with the DCPP Protocols. DCPP Units 1 and 2 will respond to CAISO Overgeneration related Operating Orders consistent with the DCPP Protocols.

7. *Pro Rata* Generation Reductions[5]

In an Overgeneration situation, the CAISO may issue an Operating Order to SCs for a "*pro rata*" generation reduction of a specified number of megawatts for each SC that represents load,[6] without specifying units to be curtailed. If PG&E receives a *pro rata* generation reduction Operating Order from the CAISO, PG&E will seek to manage such Operating Order by using reasonable efforts considering safety, operational, contractual and time limitations to implement the following protocol in the following sequence:

[5] Version 12.2 of the CAISO Overgeneration Operating Procedure (i.e., Operating Procedure 2390) that is effective as of March 13, 2014 does not include use of *pro rata* reductions. However, CAISO Tariff Section 7.8.4 allows for *pro rata* reductions to address overgeneration. This section is included in these protocols to address *pro rata* reductions if Operating Procedure 2390 is amended to include *pro rata* reductions.

[6] CAISO Tariff Section 7.8.4.

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

7 [redacted]

APPENDIX L

ATTACHMENT 1

CONFIDENTIAL

REDACTED IN ITS ENTIRETY
UNDER PROTECTIONS OF D.06-06-066
AND
CALIFORNIA PUBLIC UTILITIES CODE
SECTIONS 454.5(G) AND 583

APPENDIX M

PROCUREMENT REVIEW GROUP,

COST ALLOCATION MECHANISM GROUP,

AND INDEPENDENT EVALUATOR ADMINISTRATION

A. Procurement Review Group and Cost Allocation Mechanism Group

1. Membership

Procurement Review Group ("PRG") membership includes both organizations and individuals. The California Public Utilities Commission's ("CPUC" or "Commission") Energy Division ("ED") employees are *ex-officio* participants in the PRG. All PRG members must be nominated and then evaluated for participation in the PRG by Pacific Gas and Electric Company ("PG&E"), and then PG&E may recommend the organization(s) and individual(s) to ED for approval.

When procuring or potentially procuring Cost Allocation Mechanism ("CAM") resources pursuant to Commission Decisions ("D.") 06-07-029 and 07-09-044, or Combined Heat and Power ("CHP") resources under D.10-12-035, where the costs are allocated to all "benefitting customers" (*e.g.*, bundled, direct access, and community choice aggregation customers), PG&E will utilize an advisory CAM Group consistent with the proposal adopted in D.07-12-052, Attachment D. Organizations and/or individuals must be nominated and then evaluated for participation in the CAM Group by PG&E, and then PG&E may recommend the organization(s) and individual(s) to ED for approval. PRG members are automatically part of the CAM Group.

Organizations and/or individuals on the PRG and/or CAM Group must be non-market participants and are required to execute a Non-Disclosure Agreement ("NDA").

2. PG&E's Use of the PRG and CAM Group

PG&E consults with the PRG on a wide range of transactions generally on a monthly basis, and sometimes more often as necessary. Although the PRG only acts in an advisory capacity, PG&E actively solicits feedback from PRG members and may incorporate that feedback into its procurement processes.

Consultation with the CAM Group occurs for transactions in which the costs may be allocated to all benefitting customers, or for CHP resources procured under the settlement approved in D.10-12-035.

3. Scope of PRG and CAM Group Review

The tables below provide a more detailed discussion of specific Commission requirements for consultation with the PRG and/or CAM group. Table M-1 describes the procurement transactions and solicitations that require PRG review. Table M-2 details procurement-related activity and reporting requirements that require consultation with the PRG pursuant to the cited Commission decisions, resolutions, and directives.

TABLE M-1
PACIFIC GAS AND ELECTRIC COMPANY
TRANSACTIONS AND SOLICITATIONS REQUIRING PRG REVIEW

Line No.	Topic	Description	CPUC Decision and/or BPP Requirement
1	Transactions greater than three (3) months	Transactions with delivery terms of greater than three calendar (3) months, or one quarter in duration. PG&E will discuss how transactions meet portfolio needs, the solicitation or other procurement processes, evaluation methods, negotiation, and contract/transactions selection process.	D.04-12-048, Finding of Fact ("FOF") 73 and Ordering Paragraph ("OP") 15; D.07-12-052, Appendix E at p. 1.
		Delivery term is defined by the duration of the contract, regardless of execution date and when the deliveries begin.	D.07-12-052, p. 171.
		Except for the case of Long-Term Requests for Offers ("LTRFO"), which have specific requirements (see, below), PRG review of each explicit transaction executed according to a strategy previously reviewed by the PRG is not required prior to execution of the transaction.	[Requested Clarification]
2	LTRFOs	Design, drafting of bid documents, administration, evaluation and offer selection criteria, ranking, shortlist and resulting executed transactions.	D.07-12-052, pp. 149-150 and OPs 15 and 16.
3	CHP Request for Offers ("RFO")	PG&E consults with the PRG and CAM Group regarding CHP RFOs.	Qualifying Facility and CHP Settlement Term Sheet, Section 4.2.5.8 approved in D.10-12-035.
4	Renewable Portfolio Standard ("RPS") RFOs	PG&E consults with the PRG regarding RPS RFO issuance, evaluation, selection and short-listing, and decisions regarding offers.	D.06-05-039, FOF 20.
5	RPS transactions arising from RFOs	PG&E reviews RPS-eligible contracts arising from an RFO with the PRG before filing an Advice Letter seeking approval.	D.09-06-050, pp. 23-24.
6	RPS transactions arising from bilateral negotiations	PG&E reviews RPS-eligible contracts arising from bilateral negotiations with the PRG before filing an Advice Letter seeking approval.	D.09-06-050, p. 29 and OP 7.
7	Short-term RPS transactions	Short-term RPS transactions that satisfy certain criteria are reviewed with the PRG or an explanation is provided in the Advice Letter as to why PRG review was not possible.	D.09-06-050, p. 24 and OP 1.
8	Greenhouse Gas ("GHG") Products	PG&E consults with the PRG regarding (1) GHG RFOs and (2) prior to transacting for any GHG Product in the market with a vintage year more than three years in the future beyond the current calendar year.	D.12-04-046 at pp. 53, 55 and OP 8(g), 8(i) and PG&E's 2010 BPP, Sheet Nos. 51 and 305.
		PG&E will report to the PRG any GHG Product sales.	

Line No.	Topic	Description	CPUC Decision and/or BPP Requirement
9	Congestion Revenue Rights ("CRR") (annual and monthly CRRs) and Long-Term CRRs ("LT-CRR")	PG&E consults with its PRG prior to the start of the annual CRR process regarding its CRR position and the procurement approach and strategy for the upcoming allocation and auction tiers. This consultation does not require PG&E to provide all of the specific proposed nominations (including LT-CRR nominations) for the annual process prior to the allocation tiers and auction. PG&E also consults with the PRG prior to transacting for any CRR having a term greater than one calendar quarter. PG&E is not required to consult with the PRG prior to each monthly CRR allocation/auction process. Within five business days after the final posting of each annual and monthly process, PG&E will provide the PRG a listing of every CRR and LT-CRR awarded in the process, including the source, sink, MW quantity, term, expected value, past performance (if applicable), price (if applicable) and a description of the underlying arrangement that the CRR will hedge (or, in the case of a sale of a CRR, no longer hedge). The same information will be provided to the PRG within five business days of a transaction in the secondary market.	Resolution E-4135, p. 11-13, Finding 14, and OP 4. Resolution E-4122, p. 9-10, Findings 13-14 and OP 4. [Pending Approval]
10	Third-party Request for Bids	If PG&E elects to participate in RFOs issued by other market participants (including other load serving entities), then existing procurement oversight rules apply (i.e., PRG consultation/communication).	D.12-01-033, OP 17
11	Energy Storage RFO	PG&E is required to present the design of each energy storage RFO plan and the results of each energy storage RFO to its PRG, including the evaluation methodology applied to the bids received in response to the RFO.	D.13-10-040, Appendix A Section 3.g.
12	CAM-Eligible Procurement	PG&E is required to consult with the CAM Group regarding all CAM-eligible procurement.	D.07-12-052, pp. 129-130, OP 8, and Appendix D and Appendix E, p. 1.
13	Retention of Independent Evaluators ("IE")	PG&E consults with the PRG regarding the retention and review of IEs.	D.04-12-048 at p. 136

TABLE M-2
PACIFIC GAS AND ELECTRIC COMPANY
PROCUREMENT AND REPORTING ITEMS REQUIRING PRG REVIEW

Line No	Topic	Description	CPUC Decision and/or BPP Requirement
1	Market Conditions	Electric market conditions and fuel and power price forecasts (quarterly).	D.03-12-062, FOF 24.
2	Procurement Limits	Current position relative to approved procurement limits on a rolling 24-month forward basis, compared to previous quarter.	D.12-01-033, p. 15.
3	Hedging Plan	Prior to filing an advice letter seeking minor modifications to PG&E's Hedging Plan, PG&E will present the proposed modifications to the PRG.	Resolution E-3951, p. 6.
4	Hedging Plan – Liquidity Management Strategy	Updates required by the Hedging Plan, need for a transition plan, suspension or resumption of Hedging Plan, [redacted]	D.07-12-052, Resolution E-4362 PG&E's 2010 BPP, Sheet Nos. 50 and 176.
5	Nuclear Fuel Plan	Nuclear Fuel Plan updates and revisions.	D.07-12-052 PG&E's 2010 BPP, Sheet Nos. 135-146
6	Renewable Net Short	Update regarding PG&E's Renewable Net Short position (quarterly basis, in annual RPS procurement plans, and in RPS compliance reports).	*Administrative Law Judge Ruling Adopting Renewable Net Short Calculation Methodology*, issued in Rulemaking 11-05-005 on August 2, 2012, Appendix A, pp. 3, 5.
7	GHG Compliance Forecast	GHG compliance forecast and procurement limit updates and GHG Product transactions (quarterly).	D.12-04-046, pp. 57, 59.
8	GHG Auction Bidding Strategy	Annual review of PG&E's California Air Resources Board ("CARB") auction bidding strategy.	D.07-12-045, Resolution E-4544 PG&E's 2010 BPP, Sheet No. 305
9	CHP Targets	PG&E advises the PRG if it will be unable to meet CHP Targets.	Qualifying Facility and CHP Settlement Term Sheet, Section 9.2.2 approved in D.10-12-035.
10	Convergence Bidding	PG&E provides quarterly presentations to the PRG regarding its convergence bidding strategies, performance and market analysis. In the event that the 365-day rolling net-loss exceeds or is expected to exceed $20 million, PG&E will cease implementation of all convergence bidding strategies and confer with the PRG.	D.10-12-034, OP 7-8.

Line No	Topic	Description	CPUC Decision and/or BPP Requirement
11	Customer Risk Tolerance ("CRT") and TeVaR	PG&E provides a monthly update of its portfolio position and risk, including CRT and TeVaR. If the CRT is expected to be hit or exceeded within the next quarter, PG&E informs and confers with the PRG to discuss the underlying risk drivers and factors affecting the change in portfolio risk, and to determine whether specific hedging strategies and/or plan modifications are needed to reduce portfolio risk to within the CRT threshold.	D.03-12-062, p. 16 and OP 5, D.07-12-052 and D.12-01-033.
12	CRRs and LT-CRRs	PG&E is required to review its CRR position with the PRG periodically, at least once per year. PG&E provides the PRG quarterly updates on how each of its previously obtained LT-CRRs are performing, including but not limited to source, sink, term, relation to grid use, expected value, and past performance.	Resolution E-4135, p. 11-13, Findings 13-14. and OP 4. Resolution E-4122, p. 9-10, Findings 13-14 and OP 4. [Pending Approval]

4. Meeting and Notification Requirements

Agendas: PG&E will provide PRG members with final meeting agendas and materials at a minimum of 48 business hours in advance of the PRG meeting, unless there are unusual, extenuating circumstances where PG&E communicates to PRG members in an e-mail announcing a meeting or distributing meeting materials on a tighter timeframe.[1]

Summaries: PG&E will provide confidential meeting summaries to PRG members that include a list of attending PRG members (including the organizations represented), a summary of topics presented and discussed, and a list of information requested or offered to be supplied after the meeting, and the identity of the requesting party.[2] PG&E will distribute meeting summaries on the earlier of: (a) 14 days after the PRG meeting; or (b) 48 business hours before the next regularly scheduled PRG meeting. If, due to unusual circumstances the aforementioned timeframe is deemed unreasonable,

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[1] D.07-12-052, Appendix E, p. 1.

[2] *Id.*

then PG&E may distribute the summary 21 days after the PRG meeting, but may do so only if PG&E notifies the PRG members (via email) informing them of the delay in distribution.

Web-Based Calendar: PG&E maintains a web-based PRG calendar. PG&E will provide the following information to the public through a web-based forum: date, meeting time, and duration of the meeting; the individuals participating in the meeting and the organization represented by the individual; and a list of non-confidential items discussed or a summary of general topics discussed.[3]

Notifications to the PRG: In addition to the agenda, presentations, and meeting summaries, PG&E may provide notification to the PRG in-between scheduled meetings.

B. Independent Evaluators

1. Independent Evaluator Pool

PG&E, in consultation with its PRG, shall develop a pool of at least three, but preferably more IEs. PG&E will develop and periodically add to its IE pool as follows:

1) PG&E shall develop a list of prospective IEs via industry contacts, literature searches, PRG recommendations, and similar methods. PG&E will solicit information from the prospective IEs and circulate the list of candidates and their "resumes" to the PRG and ED for feedback. All individuals who perform the specific IE responsibilities and duties are covered under the IE organization or company.

2) PG&E shall rely on the guidance regarding IE expertise and qualifications provided in D.04-12-048, D.07-12-052 and D.12-01-033. However, these qualifications should represent the minimum threshold necessary for an IE to be effective, and PG&E and the PRG will evaluate all relevant, energy procurement-related knowledge, skill, and experience as part of the IE selection process.

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3 *Id.*

3) PG&E and its PRG shall identify and interview a subset of prospective candidates that PG&E, the PRG and ED staff deem most suitable for the role.

4) PG&E shall coordinate materials and submit its recommendations to the PRG regarding each prospective candidate (including the general consensus and any opposition to the consensus). PG&E shall submit a written list of qualified IEs to ED to add to the contracting pool. The list will contain the recommendations of the PRG that were submitted to the PRG. ED will evaluate the proposed IE's competencies based on the guidelines in D.04-12-048 as well as evaluating the IE's independence, including any conflicts of interest. ED shall give final approval for inclusion of an IE in the IE pool by letter to PG&E. ED will also have the right to final approval of the use of a particular IE for each RFO.

5) Beyond the development of the initial IE pool, additional IEs may be added to the pool by following the same procedures listed above.

6) An IE may remain in the IE pool for three (3) consecutive years, within which they must go through a re-evaluation process based upon the inclusion criteria to assure continued compliance. The re-evaluation process will involve additional reviews of the IE candidate by PG&E, the PRG, and ED staff, including additional interviews, or the use of other evaluation tools, if necessary. The re-evaluation of an IE is based on both the organization and the individuals who have participated as an IE within that organization. The conclusions may include the inclusion of an organization and specific IEs in that organization. The resulting conclusions may also identify the specific IEs that will not continue in the pool for the next successive three years.

7) PG&E has developed a pro forma master contract to be used each time it contracts with an IE. If deviations from the pro forma contract are necessary, then the modifications must be approved by the ED.[4]

PG&E will provide to the PRG the name of the IE to be used in a specific procurement solicitation, along with the estimated and actual IE costs before and after the solicitation takes place.[5]

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[4] *Id.*, pp. 137-138 and Appendix E, pp. 2-3, as affirmed and modified in D.14-02-040, p. 68.

[5] *Id.*, Appendix E, p. 3.

2. Independent Evaluator Requirements

Line No.	Topic	Description	CPUC Decision and/or BPP Requirement
1	RFOs	An IE will be retained for all competitive solicitations that involve: (1) a utility affiliate or utility-owned generation bids; and (2) RFOs seeking supply-side resources issued to satisfy the service area need, seeking products greater than two years in duration.	D.04-12-048, pp. 135-136; D.07-12-052, p. 140 and Appendix E, p. 3 D.08-11-008, OP 2.
2	LTRFOs	An IE will be retained to review the design, drafting of documents, administration, evaluation aspects, and offer selection or rejection of LTRFOs for long-term procurement (*i.e.*, transactions five years or greater in duration).	D.04-12-048, p. 136; D.07-12-052, pp. 149-150 and OP 15.
3	CHP RFOs	PG&E utilizes IEs for CHP RFOs to review the evaluation process.	Qualifying Facility and CHP Settlement Term Sheet, Section 4.2.5.8, approved in D.10-12-035.
4	RPS RFOs	An IE will be retained for all RFOs for RPS-eligible resources, and report on the solicitation, evaluation and selection processes.	D.06-05-039, pp. 46-47, FOF 20 and OP 8; D.09-06-050, p. 24.
5	RPS Transactions arising from bilateral negotiations	IEs provide reports on RPS-eligible contracts arising from bilateral negotiations with advice letters seeking approval.	D.09-06-050, p. 29 and OP 7.
6	Short-Term RPS Transactions	IEs review short-term RPS transactions, if applicable.	D.09-06-050, p. 24 and OP 1.
7	RPS Contract Amendments	Review of RPS contract amendments affecting contract price, including developer cash flow models.	Resolution E-4199, pp. 27-28.
8	CAM Resources	Any RFO or bilateral contract that produces a CAM-eligible resource must be overseen by an IE.	D.06-07-029, OP 1.
9	Affiliate Transactions, Not Associated with an RFO	IEs to be retained for all negotiated utility affiliate or utility-owned generation non-RFO related bids, greater than two years in duration.	D.04-12-048, pp. 135-136; D.07-12-052, p. 140 and Appendix E, p. 3 D.08-11-008, OP 2.
10	Energy Storage RFOs	An IE will be retained for all Energy Storage RFOs, and report on the solicitation, evaluation and selection processes.	D.13-10-040, pp. 10-11, 26-27, OP 8.

3. Independent Evaluator Reports

Any required IE Report shall be included with the Quarterly Compliance Report ("QCR"), Advice Letter or Application seeking approval for the specific transaction.

IEs shall use the template(s) approved by the ED. The template(s) may be modified by ED or the Commission as appropriate. Public versions of IE reports shall be identical to the corresponding confidential versions, except for the redaction of confidential material.

4. Independent Evaluator Disclosure Requirements

PG&E has developed a comprehensive conflict-of-interest disclosure requirement for IEs. An IE may be disqualified from participating in an RFO process if there are particular egregious conflicts-of-interest that arise during the RFO review process or during the contract negotiation process. An IE may also be disqualified from the IE pool if there are particular egregious conflicts-of-interests not disclosed during the evaluation process. In addition, PG&E requires that all IEs sign an NDA, which addresses potential conflicts of interest, including, but not limited to, establishing business relationships between the IE and the parties to the transaction (of which they are evaluating).

APPENDIX N

RISK MANAGEMENT POLICY

AND TEVAR METHODOLOGY

A. Risk Management Policy and Strategy

1. Portfolio Risk Assessment and Customer Risk Tolerance

Pacific Gas and Electric Company ("PG&E") manages the net open positions of the bundled electric portfolio in accordance with the California Public Utilities Commission ("CPUC" or "Commission") guidelines. The portfolio, and PG&E's ability to manage the portfolio, is affected by numerous risks, including: price, market liquidity, model, counterparty credit exposure, and credit liquidity.

First, with regard to price risk, increases in electricity, gas and greenhouse gas ("GHG") compliance instrument prices increase the costs of the portfolio and increase the risk of even higher costs of the portfolio. Increases in price volatility also increase the risk of higher costs of the portfolio. The portfolio's exposure to price risk is included in the To-expiration Value-at-Risk ("TeVaR") measure. Among the challenges in managing the portfolio's exposure to price risk are balancing how much to hedge, when to hedge, and what products to use to hedge.

Second, the portfolio and PG&E face market liquidity risk. Depending on the size of the portfolio's net open positions, prices may move adversely when transactions are executed to reduce those net open positions. Depending on market conditions, this adverse price movement could be significant. In formulating a plan to execute transactions, and in actual transaction execution, PG&E considers the potential effects of market liquidity risk.

Third, the portfolio and PG&E can be affected by model risk. Model risk relates to the risks involved in using models to estimate portfolio risk and manage the portfolio's net open positions. Often, PG&E's portfolio positions are not directly traded in any marketplace. In this situation, models are used to estimate net open position exposure, measure portfolio risk, and guide in managing the portfolio. Model risk includes the risk of estimating, extrapolating, or forecasting inputs needed for portfolio evaluation, such as energy demand, hydro supply, forward prices, volatilities, and correlations. PG&E's risk management policies and procedures include provisions and activities to assess and manage model risk.

Fourth, the portfolio and PG&E can be affected by counterparty credit risk. The portfolio and PG&E hold contracts with counterparties, and there is a risk that counterparties may not pay or perform on their contractual obligations. PG&E's credit department manages this risk. Since returning to procurement in 2003, PG&E's credit department has employed a credit policy whereby all transactions with counterparties are subject to term and dollar limits. Generally, these limits are based on collateral thresholds, credit ratings, and contractual conditions that both PG&E and counterparties have agreed to for managing collateral obligation of each party to more effectively manage counterparty credit risk.

Additionally, the portfolio and PG&E face credit liquidity risk. PG&E is obligated to post collateral with counterparties as well as exchanges. The collateral posting by PG&E results from the combination of accruals for delivered physical energy and mark to market of obligations above and beyond the negotiated credit threshold with counterparties. In addition, most of the portfolio's contractual agreements require PG&E to post collateral if PG&E's credit rating by external rating agencies were to fall below investment grade. For exchanges and cleared transactions, PG&E is required to post initial margin as well as mark to market and the portfolio does not benefit from any unsecured credit limits.

PG&E reports its electric portfolio TeVaR to the Commission's Energy Division ("ED") on a monthly basis.[1] Consistent with Decision ("D.") 07-12-052, PG&E measures TeVaR as the potential change in portfolio costs under a low probability (5 percent) outcome or a 95 percent confidence level. The TeVaR measure assumes that no further forward hedging is performed, and that all existing positions are taken to delivery. In D.12-01-033, the Customer Risk Tolerance ("CRT") level was set by the Commission at 10 percent of PG&E's system average rate. The calculation of the CRT value is derived by multiplying 10 percent of the adopted bundled system average rate by the bundled forecasted sales for the rolling 12-month period. Based on PG&E's effective January 2014 bundled system average rate of 16.3 cents per kilowatt-hour ("kWh"),[2] a 10 percent risk tolerance factor yields a CRT of 1.63 cents/kWh. Pursuant to D.12-01-033, this CRT calculation will be updated every two years in each Long-Term Procurement Plan ("LTPP") filing. If the LTPP filing is delayed or not made, the CRT will be updated two years from the filing of the previous LTPP via a Tier 1 advice letter. A description of PG&E's TeVaR methodology is included in Section B below.

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[1] *See also* Appendix M (regarding TeVaR notification to the Procurement Review Group as required by D.07-12-052 and D.12-01-033).

[2] PG&E Advice Letter ("AL") 4278-E-B "Supplemental Filing – Annual Electric True-Up – Consolidated Changes to PG&E Electric Rates on January 1, 2014" http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4278-E-B.pdf.

2. Current Risk Management Practices

PG&E hedges the price risk of its portfolio in accordance with its Commission-approved Electric Portfolio Hedging Plan (Hedging Plan or Plan).[3] Under the Hedging Plan, PG&E is authorized to utilize financial instruments in addition to physical contracts to hedge its price risk. The Hedging Plan provides PG&E with an approved guideline for volume, term and tenor, and permitted product type. The Hedging Plan also establishes the credit liquidity amount that can be allocated to the hedging of PG&E's electric portfolio as outlined in the Liquidity Management Strategy section.

PG&E hedges using Swaps and Options, as well as fixed-price contracts. These hedges complement other portfolio positions. A significant fraction of portfolio price risk is currently "hedged" through PG&E's ownership of physical assets or the rights to output from physical assets (power plants, long-term power contracts, gas pipelines, and gas in storage). Along with existing physical positions, PG&E uses financial Swaps and Options to further hedge commodity price risk.

PG&E's selection of financial hedge instruments is guided by its Hedging Plan. An Option requires a known up-front payment, and could result in a later cash inflow that is unknown until expiration and settlement. On the other hand, a financial Swap has no up-front payment and results in a later cash inflow or outflow that is unknown until expiration and settlement. Swaps are also subject to collateral posting requirements and do not allow the buyer to take advantage of lower prices if commodity prices drop in the future.

[3] The Electric Portfolio Hedging Plan is in Appendix E.

Typically, PG&E is the buyer of the hedge instruments. On rare occasions, PG&E anticipates, in advance, having more commodity than needed to serve customer demand. On such occasions, the sale of hedge instruments would serve as a hedge reducing the portfolio's exposure to commodity price risk.

Finally, it is important to note that while hedging reduces the risk of adverse price movements and leads to more stable portfolio costs, hedging does not reduce the expected (that is, average or mean) portfolio cost.

3. Credit and Collateral Requirements

The Commission has not established specific rules for counterparty or customer risk that apply to credit exposure. PG&E's credit and collateral requirements evolved from accepted energy industry practices, including concepts that can be found in Edison Electric Institute ("EEI"), North American Energy Standards Board ("NAESB"), and International Swaps and Derivatives Association, Inc. ("ISDA") master agreements. The primary elements of PG&E's credit and collateral requirements include: collateral thresholds (unsecured credit lines), collateral posting for purchases and sales of physical or financial gas and power, and mark to market posting to cover the change in value of a contract relative to the market. The general goal is to protect customers against the risk of default by parties with whom PG&E enters into wholesale commodity transactions or hedging transactions. PG&E's credit risk management process includes: creditworthiness evaluations, collateral requirements for various types of transactions, and the level of collateral authority. Each of these aspects of credit risk management is described below.

PG&E manages the credit risk regarding each counterparty by assigning unsecured credit limits or unsecured credit thresholds to each counterparty. In establishing unsecured credit lines for counterparties, PG&E performs evaluations of counterparty creditworthiness. PG&E assesses each counterparty's financial strength, transaction risk and duration, credit standing, and other credit criteria, as deemed appropriate. PG&E periodically reviews the unsecured credit lines assigned to a counterparty to ensure the unsecured credit lines are appropriate for the then-current credit quality of the counterparty.

Some counterparties may have their debt rated by Standard and Poor's ("S&P"), Moody's or Fitch. A credit rating of BBB- or higher by S&P or Baa3 by Moody's is considered investment grade. If a counterparty is investment grade rated by the agencies and it also meets PG&E's credit evaluation criteria, it may then qualify for some unsecured credit amount. If a counterparty is not rated by a rating agency, it may still qualify for some unsecured credit limit if it meets PG&E's credit evaluation criteria. Otherwise, for all other counterparties credit support may be required in the form of a cash deposit, guaranty from an investment grade entity, or a letter of credit from an acceptable credit support provider, in form and substance satisfactory to PG&E.

Counterparties which qualify for unsecured credit may still need to post additional collateral if the expected exposure is beyond the assigned credit limit.

Some of the specific collateral requirements that apply to various categories of transactions are described below.

- **Standard Physical Contracts** – Physical power contracts are generally executed under standard agreements such as the Western System Power Pool, or EEI form master agreements. These master agreements generally have a credit annex where parties can specify unsecured credit limits and conditions that apply for parties to honor the levels. For natural gas physical contracts, either NAESB or Gas Industries Standards Board are commonly used. Credit terms of the master agreements for natural gas have similar clause and treatment as power. For the most part power and gas contract exposure cannot be netted without a bridging agreement. Bridging agreements are difficult to establish as the executed contracts may be with various subsidiary or affiliate of a credit support provider.

- **Standard Financial Contracts** – Financial transactions are executed directly through the exchanges or executed directly with a counterparty in the Over-The-Counter ("O-T-C") market. When executed with exchanges, PG&E must post appropriate collateral based on the exchange's requirements for initial margin and ongoing margin maintenance associated with mark to market value of the transactions on a daily basis. O-T-C transactions can be submitted for clearing with a clearing entity such as the Intercontinental Exchange, or remain with the counterparty. Similar to exchanges, cleared contracts will require collateral posting based on the mark to market value of the contracts. O-T-C financial transactions are generally executed under the negotiated terms of the ISDA. Similar to standard physical agreement, an ISDA master agreement has a credit annex for specifying conditions and level of unsecured credit limit among the parties to the agreement. The Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted in July 2010. This act introduced new rules in order to mitigate financial risks related to O-T-C financial transactions. The act introduced rules related to reporting, record keeping, clearing requirements, entity declarations, and transactional disclosures. PG&E is in full compliance with the Dodd-Frank financial reform requirements.

- **Renewable Contracts** – Renewable counterparties may be required to post various deposits consisting of a bid deposit, which is later increased to a development and construction period deposit (amount of security designated in $/kW) and multiplied by the greater of: (1) the capacity factor; or (2) 0.5 for intermittent technologies; and a delivery term security of up to 12 months of the average revenue depending on contract term once commercial operations begin.

- **Greenhouse Gas Contracts** – PG&E utilizes both Allowances and Offset Credits ("Offsets"), as described in Appendices A and G, to meet its compliance obligations. For bilateral transactions, PG&E may require a security to cover the expected exposure and an additional security specifically for Offsets invalidation risk after delivery.

- **Resource Adequacy ("RA")** – RA counterparties (if not rated as investment grade) are generally required to post collateral depending on the terms of the agreement.

- **Tolling Contracts** – Intermediate-term tolling counterparties are subject to mark-to-market posting in accordance to the Market Intrinsic Value or equivalent methodology. Long-term tolling counterparties may be required to post a bid deposit plus an additional amount when an executed contract is submitted to the Commission; plus an additional developmental and construction period deposit is required at the time the Commission approves the contract (amount of security designated in $/kilowatt ("kW")); and once commercial operations begin the counterparty is subject to the Market Intrinsic Value or equivalent methodology.

- **Procurement Activities Through the California Independent System Operators ("CAISO")** – PG&E schedules all its energy procurement through the CAISO system. It also procures a portion of its physical needs daily and hourly through the CAISO or may resell any excess energy it may have. In addition, PG&E manages transmission congestion risks through procurement of financial contracts for Congestion Revenue Rights ("CRR") through the CAISO auction and term allocation process. PG&E is also responsible for various CAISO charges related to Transmission and Distribution, Losses, and administrative. The combined exposure to a market participant is referred to as Estimated Aggregate Liability ("EAL") by the CAISO and is used for monitoring and collecting appropriate level of security to mitigate counterparty risk. The CAISO allocates a maximum of $50 million of unsecured credit to the most creditworthy market participants. PG&E currently qualifies for this unsecured credit limit, but must post additional collateral above and beyond the $50 million limit within two business day of receiving the request from the CAISO. In addition, during the period of bidding for CRR or during convergence bidding, PG&E may need to maintain additional amount of collateral above and beyond the projected daily EAL to ensure its bids are not rejected because of lack of credit support.

- **Short-Term Transactions** – Short-term transactions include hour-ahead, day ahead, balance of the month, and multi-month deals. Exposures from purchases and sales of power and gas are tracked daily. Collateral requirements are governed by the master agreements under which these transactions are executed.

D.09-05-002 grants PG&E, among other things, authority to issue up to $4.0 billion of short-term debt, subject to the restriction that $500 million of that authority may only be used for the following purposes:

– Procuring natural gas for PG&E's customers during price spikes.[4]

– Procuring electricity for PG&E's customers during price spikes.

– Responding to major natural disasters, large scale terrorist attacks, or other cataclysms.

– Providing liquidity during a major disruption of PG&E's ability to bill, collect, and/or process utility customer bills.

Given these restrictions, PG&E effectively has $3.5 billion of general short-term debt authority, with the additional $500 million of authorization reserved for the foregoing specified contingencies. Short-term debt is used to meet the liquidity requirements of the electric portfolio and finance other operations at PG&E. The liquidity management structure specified in Appendix E deploys short-term debt to the electric portfolio.

B. TeVaR Methodology

Fluctuations in natural gas, electric power and GHG prices, hydroelectric generation, and electric load variations result in fluctuations in the overall cost of the PG&E electric portfolio. The TeVaR metric is a measure of unexpected changes in PG&E's variable electric portfolio procurement costs, net of electric portfolio revenues

[4] D.04-10-037 defines the commencement of a "price spike" as an increase in the price of gas or electricity of at least 50 percent over the average of the preceding 12 months.

from sales of cumulative long positions over some specified time period, typically 12 months. TeVaR measures how high the net portfolio cost for the projection period may become if certain market changes occur.

Revenues and costs which accrue to PG&E's electric portfolio, and thus to PG&E customers, depend on prices for natural gas and power at specific locations. Currently, PG&E's TeVaR model includes forward and spot natural gas daily prices, and forward and day-ahead electricity prices. Day-ahead electricity prices are based on time of use, such as super-peak hours (hour ending 13 through 20 Monday through Friday), on-peak but not super-peak hours (hour ending 7 through 22 Monday through Saturday except Super-peak hours), "Sunday and holiday" hours, off-peak hours (all other remaining hours).

The TeVaR metric is computed using a Monte Carlo simulation. In this simulation, for each Monte Carlo "trial," daily spot prices are randomly generated for each of the specified locations and for each day of the projection period, and hydro generation and electric load are simulated at hourly level for the projection period. Daily electricity spot prices are further shaped into time-of-use prices. Forward prices for natural gas and electricity are also simulated to compute pay-off from the financial hedge positions (swaps and options). The prices used in the simulation are consistent with current market forward prices, volatility term-structures implied by market data, and with historical correlations of market data. For each day of the projection period, the net cost at delivery is computed for every position in the portfolio. Net costs over the projection period then produce a single (aggregated) net cost for each such trial. The variation of net costs over trials produces a probability distribution of net costs. Costs are represented as negative numbers, so the 1st percentile in the distribution of net cost represents more cost to customers than the 10th percentile in the same distribution of net cost. The difference between the mean net cost and the 5th percentile of net cost is identified as TeVaR at the 95th percentile ("TeVaR95").

TeVaR95 represents the largest additional unexpected variable procurement cost for PG&E's electric portfolio, with probability 0.95. There is a 0.05 probability that unexpected costs can be even greater than TeVaR95. Using TeVaR95 to measure portfolio risk enables close monitoring of potential unexpected costs to PG&E's customers.

Long-term forecast TeVaR values are shown and discussed with other detailed scenario forecast values in Appendix D.

APPENDIX O

ACRONYM LIST AND GLOSSARY

ACRONYM LIST

Acronym	Full Name
A.	Application
AB	Assembly Bill
ACEEE	American Council for an Energy Efficient Economy
ADS	Automated Dispatch System
AL	Advice Letter
AMP	Aggregator Managed Portfolio Program
APCR	Allowance Price Containment Reserve
A/S	Ancillary Services
BIP	Base Interruptible Program
BNEF	Bloomberg New Energy Finance
BPP	Bundled Procurement Plan
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBP	Capacity Bidding Program
CC	Combined Cycle
CCA	Community Choice Aggregation
CDWR or DWR	California Department of Water Resources
CEC	California Energy Commission
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity

Acronym	Full Name
CPI	Consumer Price Index
CPUC or Commission	California Public Utilities Commission
CRR	Congestion Revenue Rights
CRT	Customer Risk Tolerance
CSI	California Solar Initiative
D.	Decision
DA	Direct Access
DAM	Day-Ahead Market
DBP	Demand Bidding Program
DCPP	Diablo Canyon Power Plant
DEC	decremental
DG	Distributed Generation
DR	Demand Response
DSM	Demand-Side Management
EAL	Estimated Aggregate Liability
EAP	Energy Action Plan
ED	Energy Division
EDU	Electric Distribution Utility
EE	Energy Efficiency
EEI	Edison Electric Institute

Acronym	Full Name
Energy Storage Plan	Energy Storage Procurement Plan
Enricher	Enrichment Services Supplier
EP	PG&E's Energy Procurement organization
ERRA	Energy Resource Recovery Account
ETS	Emissions Trading System
EUP	Enriched Uranium Product
FCM	Futures Commission Merchant
FERC	Federal Energy Regulatory Commission
FIT	Feed-in Tariff
FMM	Fifteen-Minute Market
FNM	Full Network Model
FTR	Firm Transmission Rights
GDP-IPD	Gross Domestic Product – Implicit Price Deflator
GHG	Greenhouse Gas
GHG Products	GHG-Related Products
GSP	Gas Supply Plan
GWh	gigawatt-hour
HASP	Hour Ahead Scheduling Process
HST	Hydrostatic Testing
ICE	Intercontinental Exchange
ID	Irrigation District

Acronym	Full Name
IE	Independent Evaluator
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
IS	Indicated Shippers
ISDA	International Swaps and Derivatives Association, Inc.
JPA	Joint Powers Authority
kgU	kilograms Uranium
kW	kilowatt
kWh	kilowatt-hour
lbs.	pounds
LCBF	Least-Cost, Best-Fit
LCD	Least-Cost Dispatch
LCR	Load Control Receivers
LMP	Locational Marginal Price
LMPM	Local Market Power Mitigation
LOT	Lower Operating Target
LSE	Load Serving Entity
LT	Long-Term
LT-CRR	Long-Term Congestion Revenue Rights
LTPP	Long-Term Procurement Plan

Acronym	Full Name
LTRFO	Long-Term Request for Offers
MCE	Marin Clean Energy
MCRM	Market and Credit Risk Management
MDS	Market Data System
MMBtu	Millions of British Thermal Units
MRR	Mandatory Reporting Rule
MRTU	Market Redesign and Technology Upgrade
MSG	Multi-Stage Generation
$mtCO_2e$	metric tons of carbon dioxide equivalent
MW	megawatts
MWe	megawatt electrical
MWh	megawatt-hour
NAESB	North American Energy Standards Board
NEM	Net Energy Metering
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange
NMV	Net Market Value
NDA	Non-Disclosure Agreement
Non FTR	Non-Firm Transmission Rights
NP 15	North of Path-15

Acronym	Full Name
NQC	Net Qualifying Capacity
NSC	Net Surplus Compensation
NYMEX	New York Mercantile Exchange
O&M	operations and maintenance
Offsets	Offset Credits
OP	Ordering Paragraph
ORA	Office of Ratepayer Advocates
OTC	Once Through Cooling
O-T-C	Over-The-Counter
PCC1	Portfolio Content Category one
PDP	Peak Day Pricing
PDR	Proxy Demand Response
PG&E	Pacific Gas and Electric Company
PGA	Participating Generator Agreement
PL	Participating Load
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PRG	Procurement Review Group
PSE	Puget Sound Energy
Pub. Util. Code	Public Utilities Code
PV	Photovoltaic

Acronym	Full Name
QCR	Quarterly Compliance Report
QF	Qualifying Facility
QF/CHP Settlement	Qualifying Facility and Combined Heat and Power Settlement
R.	Rulemaking
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
RDRR	Reliability Demand Response Resource
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RFO	Request for Offers
RFP	Request for Proposals
RPS	Renewables Portfolio Standard
RTEM	Real-Time Economic Market
RTD	Real-Time Dispatch
RTM	Real-Time Market
RTUC	Real-Time Unit Commitment
S&P	Standard and Poor’s
S&T	Supplier’s and Transporter’s
SB	Senate Bill
SC	Scheduling Coordinator

Acronym	Full Name
SCE	Southern California Edison Company
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SI	Strategic Inventory
SOC	Standard of Conduct
SRAC	Short-Run Avoided Cost
STES	Short-Term Electric Supply
STUC	Short-Term Unit Commitment
SWRCB	State Water Resources Control Board
SWU	Separative Work Unit
T&D	Transmission and Distribution
TeVaR	To-expiration Value-at-Risk
TeVaR95	TeVaR at the 95th percentile
TPO	third-party owned
TREC	Tradable Renewable Energy Credits
U3O8	Uranium Concentrates
UF6	Uranium Hexafluoride
UOG	Utility-Owned Generation
UOT	Upper Operating Target

Acronym	Full Name
U.S.	United States
WECC	Western Electric Coordinating Council
WMDVBE	Women, Minority, or Disabled Veteran-Owned Business Enterprises
WREGIS	Western Renewable Energy Generation Information System
ZNE	Zero Net Energy

GLOSSARY

A

AUTOMATED DISPATCH SYSTEM (ADS) – The CAISO systems application to communicate dispatch instructions to Scheduling Coordinators.

AFFILIATE – A company that is controlled by another or that has the same owner as another company.

AGGREGATION – The process of organizing small groups, businesses or residential customer into a larger, more effective bargaining unit that strengthens their purchasing power with utilities.

AGGREGATOR – An entity that puts together customers into a buying group for the purchase of a commodity service. The vertically integrated investor-owned utility, municipal utilities and rural electric cooperatives perform this function in today's power market. Other entities such as buyer cooperatives or brokers could perform this function in a restructured power market.

ANCILLARY SERVICES – Regulation, Spinning Reserve, Non-Spinning Reserve, Voltage Support and Black Start together with such other interconnected operation services as the CAISO may develop in cooperation with market participants to support the transmission of energy from generation resources to loads while maintaining reliable operation of the CAISO-controlled grid in accordance with WECC standards and Good Utility Practice.

AREA LOAD – The electrical load in given geographic area irrespective of what LSEs are providing generation services to end-users within the area.

AVERAGE COST – The revenue requirement of a utility divided by the utility's sales. Average cost typically includes the costs of existing power plants, transmission, and distribution lines, and other facilities used by a utility to serve its customers. It also included operating and maintenance, tax, and fuel expenses.

AVOIDED COST (Regulatory) – The amount of money that an electric utility would need to spend for the next increment of electric generation to produce or purchase elsewhere the power that it instead buys from a cogenerator or small-power producer.

B

BALANCING AUTHORITY AREA – The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

BASELINE METHOD – A prediction of future energy needs which does not take into account the likely effects of new conservation programs that have not yet been started.

BILATERAL CONTRACT – A two-party agreement for the purchase and the sale of products and/or services.

BIOGAS – Methane produced by the decomposition or processing of organic matter.

BIOMETHANE (Purchase or Sale) – Pipeline quality natural gas produced from renewable (non-fossil based) resources. May include renewable or environmental attributes.

BLACK START – The procedure by which a generating unit self-starts without an external source of electricity thereby restoring a source of power to the CAISO Balancing Authority Area following system or local area blackouts.

BRITISH THERMAL UNIT (Btu) – The quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, 778 foot-pounds, 1,055 joules or 0.293 watt hours.

BUNDLED CUSTOMERS – Bundled customers are those customers of the IOU for whom the IOU provides a suite of "bundled" services, including procuring and supplying electricity, as well as providing transmission, distribution and customer services.

BUYER – An entity that purchases electrical energy or services from an Exchange or through a bilateral contract on behalf of end-use customers.

C

CALIFORNIA ENERGY COMMISSION – The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act in 1974 (Public Resources Code, Sections 25000, *et seq.*) responsible for energy policy. The Energy Commission's five major areas of responsibilities are:

1. Forecasting future statewide energy needs;
2. Licensing power plants sufficient to meet those needs;
3. Promoting energy conservation and efficiency measures;

4. Developing renewable and alternative energy resources, including providing assistance to develop clean transportation fuels; and

5. Planning for and directing state response to energy emergencies.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) – an independent, non-profit independent system operator serving California that oversees the operation of California's bulk electric power system, transmission lines, and electricity market generated and transmitted by its member utilities. The CAISO was created by California Public Utilities Code § 345, *et. seq*.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) – A state agency created by constitutional amendment in 1911 to regulate the rates and services of more than 1,500 privately-owned utilities and 20,000 transportation companies. The CPUC is an administrative agency that exercises both legislative and judicial powers; its decisions and orders may be appealed only to the California Supreme Court.

CAPABILITY – Maximum load that a generating unit can carry without exceeding approved limits.

CAPACITY (Demand side) – The amount of power consumed by a customer, measured in MWs, that can be produced upon request.

CAPACITY (Purchase or Sale) – The amount of power capable of being generated, measured in MWs, that can be reduced upon request.

CAPACITY FACTOR – A percentage that tells how much of a power plant's capacity is used over time. For example, typical plant capacity factors range as high as 80 percent for geothermal and 70 percent for cogeneration.

CARBON DIOXIDE – A colorless, odorless, non-poisonous gas that is a normal part of the air. Carbon dioxide, also called CO_2, is exhaled by humans and animals and is absorbed by green growing things and by the sea.

COGENERATOR – Cogenerators use the waste heat created by one process, for example during manufacturing, to produce steam which is used, in turn, to spin a turbine and generate electricity.

COMBINED CYCLE PLANT – An electric generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.

COMBUSTION – Rapid oxidation, with the release of energy in the form of heat and light.

COMMERCIAL OPERATION – Occurs when control of the generator is turned over to the system dispatcher.

COMMUNITY CHOICE AGGREGATION CUSTOMERS – Customers who live in any city, county, or city and county, or group of cities, counties, or cities and counties, whose governing board or boards elect to combine the loads of their residents, businesses, and municipal facilities in a community wide electricity buyers' program. (See PU Code § 331.5.).

COMPETITIVE PROCESS – This is a procedure that utilities use to select suppliers of new electric capacity and energy. Under a competitive process, an electric utility solicits bids from prospective power generators to meet current or future power demands.

CONGESTION – A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously.

CONGESTION MANAGEMENT – Alleviation of congestion by the ISO.

CONTINGENT FORWARD (Purchase or Sale) – A contract entered into in advance of delivery time, the performance of which is contingent upon the subsequent occurrence of one or more events agreed upon by the counterparties.

COUNTERPARTY SLEEVES (For Electric Products) – An agreement by a counterparty to buy (sell) electricity from one counterparty and sell it to (buy it from) another counterparty.

COUNTERPARTY SLEEVES (For Natural Gas Physical Products) – Facilitating a transaction with an un-contracted or non-creditworthy through a contracted, creditworthy counterparty.

D

DAY-AHEAD MARKET (DAM) – A series of processes conducted in the Day-Ahead that includes the Market Power Mitigation-Reliability Requirement Determination, the Integrated Forward Market and the Residual Unit Commitment.

DAY-AHEAD SCHEDULE – A schedule issued by the CAISO one day prior to the target trading day indicating the levels of supply and demand for energy cleared through the IFM and scheduled for each settlement period, for each Pnode or Aggregated Pricing Node, including scheduling points of that trading day.

DELIVERY POINT – Point at which gas leaves a transporter's system completing a sale or transportation service transaction between the pipeline company and a sale or transportation service customer.

DEMAND (Utility) – The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts.

DEMAND RESPONSE PROGRAMS – "Demand response" refers to actions taken by end-users to reduce power demand during critical peak times or to shift demand to off-peak times. A demand response program provides customers with incentives for reducing load in response to an event signal. These incentives can take the form of a financial credit or their bill, a dynamic rate or exemption from rolling blackouts. Events can be called for economic or reliability reasons. Because demand response programs are designed to operate only a few hours per event, they typically reduce capacity (kW) but not energy (kWh).

DERIVATIVES – A specialized security or contract that has no intrinsic overall value, but whose value is based on an underlying security or factor as an index. A generic term that, in the energy field, may include options, futures, forwards, etc.

DIRECT ACCESS – The ability of end-use customers located in the service territory of an IOU to purchase electricity from retail sellers other than their local utility.

DISPATCH – The operating control of an integrated electric system to: Assign generation to specific generating plants and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls; Control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures; Operate the interconnection; and Schedule energy transactions with other interconnected electric utilities.

DISPATCHABLE – This is the ability of a generating unit to increase or decrease generation, or to be brought on line or shut down at the request of a utility's system operator.

DISTRIBUTION – The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

DISTRIBUTED GENERATION – A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

DWR CONTRACTS – Contracts for generating resource capacity and energy deliveries executed by the California Department of Water Resources during 2001 and allocated to the investor owned utilities for contract administration purposes only.

E

ECONOMIC DISPATCH – The distribution of total generation requirements among alternative sources for optimum system economy with consideration to both incremental generating costs and incremental transmission losses.

ELECTRIC DISTRIBUTION UTILITY (EDU) – The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The distribution utility can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers. The "wires" and "customer service" functions provided by a distribution utility could be split so that two totally separate entities are used to supply these two types of distribution services.

EEI CONTRACT – Edison Electric Institute contract is a standard master agreement that provides the base terms and conditions for transactions executed between two parties of the master agreement.

EFFICIENCY – The ratio of the useful energy delivered by a dynamic system (such as a machine, engine, or motor) to the energy supplied to it over the same period or cycle of operation. The ratio is usually determined under specific test conditions.

ELECTRIC SERVICE PROVIDER (ESP) – An entity that is licensed by the CPUC to provide electric power service to Direct Access Customers (see PU Code §§ 218.3 and 394). An end-use customer can act as its own ESP as long as it complies with all requirements of being an ESP. Also referred to as Energy Service Providers.

ELECTRIC SYSTEM – This term refers to all of the elements needed to distribute electrical power. It includes overhead and underground lines, poles, transformers, and other equipment.

ELECTRICITY – A property of the basic particles of matter. A form of energy having magnetic, radiant and chemical effects. Electric current is created by a flow of charged particles (electrons).

ELECTRICITY TRANSMISSION PRODUCTS – The amount of electricity transportation capability of a transmission line measured in MWs.

EMISSIONS CREDITS FUTURES OR FORWARDS – Credits or allowances for emissions that can be bought or sold in order to comply with emissions limits.

END-USER – The final consumer with the specific purpose for which electric is consumed (i.e., heating, cooling, cooking, etc.).

ENERGY – The amount of electricity produced, flowing or supplied by generation, transmission or distribution facilities or consumed over time. Usually it is measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1 kWh, 1,000 kWh = 1 MWh, etc.

ENERGY DELIVERIES – Energy generated by one system delivered to another system.

ENERGY EFFICIENCY – Programs and measures designed to reduce consumer energy consumption. Example of programs and measures include lighting retrofit, process redesign and appliance rebates which encourage consumers to purchase high-efficiency appliances.

ENERGY RESOURCES – Everything that could be used by society as a source of energy.

ENERGY USEAGE – Energy consumed during a specified time period for a specific purpose (usually expressed in kWh).

EXCHANGE (Electric utility) – Agreements between utilities providing for purchase, sale and trading of power. Usually relates to capacity (kilowatts) but sometimes energy (kilowatt-hours).

EXPORTS (Electric utility) – Power capacity or energy that a utility is required by contract to supply outside of its own service area and not covered by general rate schedules.

F

FACILITY – A location where electric energy is generated from energy sources.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) – An independent regulatory commission within the U.S. Department of Energy that has jurisdiction over energy producers that sell or transport fuels for resale in interstate commerce; the authority to set oil and gas pipeline transportation rates and to set the value of oil and gas pipelines for ratemaking purposes; and regulates wholesale electric rates and hydroelectric plant licenses.

FINANCIAL CALL (OR PUT) OPTION (For Electric Products) – The right, but not the obligation, to buy (call) a forward electric contract on a specific date (expiration) at a specific price (strike). The right to sell is a put option.

FINANCIAL OPTION (For Natural Gas Financial Products) – The right, but not the obligation, to buy (call) a forward gas contract on gas on a particular date (expiration) at a particular price (strike). The right to sell is a put option.

FINANCIAL SWAP – An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps and basis swaps. Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.

FIRM ENERGY – Power supplies that are guaranteed to be delivered under terms defined by contract.

FIRM SERVICE – Retail and wholesale service offered to customers under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in Off-Peak Service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency.

FIXED COSTS – The annual costs associated with the ownership of property such as depreciation, taxes, insurance, and the cost of capital.

FORCED OUTAGE – An outage that results from emergency conditions and requires a component to be taken out of service automatically or as soon as switching operations can be performed. The forced outage can be caused by improper operation of equipment or by human error.

FORECAST INSURANCE – A method for managing load forecast (volume and shape) risk.

FORWARD ENERGY (Demand side) – Electric energy planned to be consumed by a customer, measured in MWhs that is agreed to be reduced for a specific period for a specified time in the future.

FORWARD ENERGY (Purchase or Sale) – Electric energy purchased or sold by a counterparty, measured in MWhs that is agreed to be supplied or received for a specific period at a specific location for a specified time in the future.

FORWARD SPOT (DAY-AHEAD & HOUR-AHEAD) PURCHASE, SALE, OR EXCHANGE – Electric energy, capacity, ancillary services or transmission purchased or sold by a counterparty, or exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied, received or exchanged for a specific period at a specific location in the Day-Ahead or Hour-Ahead markets.

FREQUENCY – The number of cycles which an alternating current moves through in each second. Standard electric utility frequency in the United States is 60 cycles per second, or 60 Hertz.

FTR LOCATIONAL SWAPS – Over-the-counter basis swaps associated with Firm Transmission Rights. Swaps are financially settled directly with a counterparty or may be financially cleared through financial clearinghouse.

FUEL – A substance that can be used to produce heat.

FUEL CELL – A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

G

GAS – Gaseous fuel (usually natural gas) that is burned to produce heat energy.

GAS STORAGE (Purchase or Sale) – Includes firm and as-available storage inventory, injection and withdrawal. Also includes parking and borrowing services.

GAS TRANSPORTATION (Purchase or Sale) – Interstate, Intrastate, and distribution gas transportation services. Includes firm, as-available and interruptible services.

GENERATING STATION – A station that consists of electric generators and auxiliary equipment for converting mechanical, chemical, or nuclear energy into electric energy.

GENERATING UNIT – Any combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power.

GENERATION (Electricity) – Process of producing electric energy by transforming other forms of energy.

GENERATION COMPANY or GENERATOR – A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating units. The generation company may own the generation units or interact with the short-term market on behalf of plant owners.

GIGAWATT (GW) – One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity.

GIGAWATT-HOUR (GWH) – One million kilowatt-hours of electric power.

GREENFIELD SITE – Refers to a new electric power generating facility built from the ground up.

GRID – A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points.

H

HEAT RATE – A number that tells how efficient a fuel-burning power plant is. Measured by Btu/kWh. The heat rate equals the Btu content of the fuel input divided by the kWh or power output. The lower the heat rate of a generating unit is, the more efficient the unit is.

HEDGING – Any method of minimizing the risk of price change. Since the movement of cash prices is usually in the same direction and about in the same degree as the movement of the present prices of futures contracts, any loss (or gain) resulting from carrying the actual merchandise is approximately offset by a corresponding gain (or loss) when the contract is liquidated.

HENRY HUB – A pipeline interchange, located in Vermilion Parish, Louisiana, which serves as the delivery point of natural gas futures contracts.

HYDRO – Electricity produced by falling water that turns a turbine generator.

I

ICE – Intercontinental Exchange (ICE) is the world's leading electronic marketplace for energy trading and price discovery.

IMBALANCE ENERGY – The real-time change in generation output or demand requested by the ISO to maintain reliability of the ISO-controlled grid. Sources of imbalance energy include regulation, spinning and non-spinning reserves, replacement reserve, and energy from other generating units that are able to respond to the ISO's request for more or less energy.

IMPORTS (Electric utility) – Power capacity or energy obtained by one utility from others under purchase or exchange agreement.

INDEPENDENT SYSTEM OPERATOR (ISO) – The entity charged with reliable operation of the grid and provision of open transmission access to all market participants on a non-discriminatory basis. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

INDEX PRICE – Tying the commodity price in a contract to other published prices, such as spot prices for gas or alternate fuels, or general indexes like the Consumer Price Index or Producer Price Index.

INSTALLED CAPACITY – The total generating units' capacities in a power plant or on a total utility system. The capacity can be based on the nameplate rating or the net dependable capacity.

INSURANCE (COUNTERPARTY CREDIT INSURANCE, CROSS COMMODITY HEDGES) – A method for managing payment or performance risk for a fee.

INTERCONNECTION (Electric utility) – The linkage of transmission lines between two utilities, enabling power to be moved in either direction. Interconnections allow the utilities to help contain costs while enhancing system reliability.

INTERESTED PARTY – Any person whom the commission finds and acknowledges as having a real and direct interest in any proceeding or action carried on, under, or as a result of the operation of, this division.

INTERMITTENT RESOURCES – Resources whose output depends on some other factory that cannot be controlled by the utility, e.g., wind or sun. Thus, the capacity varies by day and by hour.

INTERRUPTIBLE SERVICE OR TARIFF (Electric utility) – Electricity supplied under agreements that allow the supplier to curtail or stop services at times. A service under which, upon notification from the Independent System Operator, the IOU requires the customer to reduce the demand imposed on the electrical system to firm service level (i.e., a level below which the customer's load will not be interruptible), and the customer must comply within 30 minutes.

INTERTIE – A transmission line that links two or more regional electric power systems.

INVESTOR-OWNED UTILITY (IOU) – A private company owned by stockholders that provides electric utility services to a specific service area. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives. A California investor-owned utility is regulated by the California Public Utilities Commission.

J

No entries for the letter J.

K

KILOWATT (kW) – One thousand (1,000) watts. A unit of measure of the amount of electricity needed to operate given equipment. On a hot summer afternoon a typical home, with central air conditioning and other equipment in use, might have a demand of four kW each hour.

KILOWATT-HOUR (kWh) – The most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt of electricity supplied for one hour.

L

LEVELIZED – A lump sum that has been divided into equal amounts over period of time.

LINE – A system of poles, conduits, wires, cables, transformers, fixtures, and accessory equipment used for the distribution of electricity to the public.

LOAD – Load is an end-use device of an end-use customer that consumes power. Load should not be confused with demand, which is the measure of power that a load receives or requires.

LOAD-SERVING ENTITY (LSE) – Any entity (or the duly designated agent of such an entity e.g., a Scheduling Coordinator), including a load aggregator or power marketer, that: (a)(i) serves end users within the CAISO Balancing Authority Area and (ii) has been granted authority or has an obligation pursuant to California state or local law, regulation, or franchise to sell electric energy to end users located within the CAISO Balancing Authority Area; (b) is a federal power marketing authority that serves end users; or (c) is the State Water Resources Development System commonly known as the State Water Project of the California Department of Water Resources.

LOCATIONAL MARGINAL PRICE (LMP) – The marginal cost ($/MWh) of serving the next increment of demand at that Pnode consistent with existing transmission facility constraints and the performance characteristics of resources.

LOSSES (Electric utility) – Electric energy or capacity that is wasted in the normal operation of a power system. Some kilowatt-hours are lost in the form of waste heat in electrical apparatus such as substation conductors. LINE LOSSES are kilowatts or kilowatt-hours lost in transmission and distribution lines under certain conditions.

M

MARGINAL COST – The sum that has to be paid the next increment of product of service. The marginal cost of electricity is the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity. In the utility context, the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.

MARKET-BASED PRICE – A price set by the mutual action of many buyers and sellers in a competitive market.

MARKET CLEARING PRICE – The price in a market at which supply equals demand. All demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.

MARKET PARTICIPANT – An entity, including a Scheduling Coordinator, who participates in the energy marketplace through the buying, selling, transmission, or distribution of energy or ancillary services into, out of, or through the ISO-controlled grid.

MASTER FILE – A file maintained by the CAISO for use in bidding and bid evaluation protocol that contains information regarding generating units, loads and other resources, or its successor.

MEGAWATT (MW) – One thousand kilowatts (1,000 kW) or one million (1,000,000) watts.

MEGAWATT HOUR (MWh) – One thousand kilowatt-hours.

METER – A device that measures the levels and volumes of a customer's gas and electricity use.

METHANE (CH4) – The first of the paraffin series of hydrocarbons. The chief constituent of natural gas. Pure methane has a heating value of 1,012 Btu per cubic foot.

MINIMUM LOAD – The lowest level of operation of oil-fired and gas-fired units at which they can be currently available to meet peak load needs.

MMBTU – A thermal unit of energy equal to 1,000,000 Btus, that is, the equivalent of 1,000 cubic feet of gas having a heating content of 1,000 Btus per cubic foot.

MUST TAKE GENERATION – Energy generation that utilities are mandated to take from specific resources or facility types identified by the CPUC. Regulatory must-take generation include QF generating units under federal law, nuclear units and pre-existing power-purchase contracts that have minimum-take provisions.

N

NATURAL GAS – Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NATURAL GAS PURCHASES (Physical Supply) – Purchases/sales/exchanges of physical natural gas for terms of one month or longer.

NETWORK – A system of transmission and distribution lines cross-connected and operated to permit multiple power supply to any principal point on it.

NON-FTR LOCATIONAL SWAPS – Over-the-counter basis swaps or futures. Swaps are financially settled directly with a counterparty or may be cleared through financial clearinghouse. Futures are traded on an Exchange or cleared through a financial clearinghouse.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL (NERC) – Council formed by electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply in utility systems of North America. NERC consists of eight regional reliability councils: Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); ReliabilityFirst Corporation (RFC); SERC Reliability Corporation (SERC); Southwest Power Pool, RE (SPP); Texas Reliability Entity (TRE); and Western Systems Coordinating Council (WECC).

NUCLEAR POWER – Energy obtained by splitting heavy atoms (fission) or joining light atoms (fusion). A nuclear energy plant uses a controlled atomic chain reaction to produce heat. The heat is used to make steam run conventional turbine generators.

NYMEX – New York Mercantile Exchange. The New York Mercantile Exchange, Inc., is the world's largest physical commodity futures exchange and the preeminent trading forum for energy and precious metals.

O

OFF-PEAK – Periods of low demands. All the time outside the on-peak period.

ON-PEAK – Periods of the highest demand.

ON-SITE ENERGY OR CAPACITY (SELF-GENERATION ON CUSTOMER SIDE OF THE METER) – The amount of power measured in MWs or MWhs generated by the customer used to offset the customer's load served by the electric service provider.

OPTIONS – An option is the right, but not the obligation, to buy or sell a fixed quantity of a security or commodity at a price and time specified in the contract.

OUTAGE (Electric utility) – An interruption of electric service that is temporary (minutes or hours) and affects a relatively small area (buildings or city blocks).

OVERGENERATION – A condition that occurs when total supply exceeds total demand in the CAISO Balancing Authority Area.

P

PARKING SERVICE – Short-term storage of a shipper's excess gas so that shipper doesn't have to sell it in the market.

PARTICIPATING GENERATOR AGREEMENT (PGA) – An agreement between the CAISO and a participating generator.

PEAK DEMAND OR PEAK LOAD – The electric load that corresponds to a maximum level of electric demand in a specified time period.

PEAK FOR OFF-PEAK EXCHANGE – Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied in an on-peak period in exchange for receiving an amount in an off-peak period.

PG&E (PACIFIC GAS AND ELECTRIC COMPANY) – An electric and natural gas utility serving the central and northern California region.

PHOTOVOLTAICS – A technology that directly converts light into electricity. The process uses modules, which are usually made up of many cells (thin layers of semiconductors).

PHYSICAL CALL (OR PUT) OPTION – The right, but not the obligation, to buy (call) physical electricity for delivery on a specific date at a fixed or indexed price (strike). The right to sell is a put option.

PHYSICAL OPTIONS ON NATURAL GAS SUPPLY (Purchase or Sale) – The right, but not the obligation, to buy (call) physical gas for delivery on a particular date at a fixed or index price (strike). The right to sell is a put option.

PIPELINE – A line of pipe with pumping machinery and apparatus (including valves, compressor units, metering stations, regulator stations, etc.) for conveying a liquid or gas.

PIPELINE CAPACITY – The maximum quantity of gas that can be moved through a pipeline system at any given time; based on existing service conditions such as available horsepower, pipeline diameter(s), maintenance schedules, regional demand for natural gas, etc.

PORTFOLIO CONTENT CATEGORY ONE (PCC1) – This category refers to facilities with first point of interconnection within a California Balancing Authority (CBA) or with generation scheduled into a CBA.

POWER – Electricity for use as energy.

POWER PLANT – A central station generating facility that produces energy.

POWER PURCHASE AGREEMENT – A contract that specifies the terms and conditions under which electric power will be generated and purchased. Power purchase agreements require the Seller to supply power under specific terms and conditions for the life of the agreement. While power purchase agreements vary, their common elements include: specification of the size, pricing structure, operating flexibility, delivery point, various service and performance obligations; dispatchability options; credit/collateral terms, and conditions of termination or default.

PRICE CURVES:

- **Forward Curve (or Futures Price)** – A term structure of forward prices observed in the market. Forward contracts, like futures, are agreements to buy or sell a commodity at a future time. Forward price is the price to be paid at delivery.
- **Price Forecast** – A projection of future price levels (these could be day-ahead prices, futures prices, monthly prices etc.) expressed either in nominal or a given year's dollars, not necessarily reflective of market prices.

PRODUCTION – The act or process of generating electric energy.

PUBLICLY-OWNED UTILITIES (POUs) – Municipal utilities (utilities owned by branches of local government) and/or cooperatives (utilities owned cooperatively by customers).

PUMPED STORAGE – Facility designed to generate electric power during peak-load periods with a hydroelectric plant using water pumped into a storage reservoir during off-peak periods.

Q

QUALIFYING FACILITY (QF) – A non-utility generator of energy that must meet certain operating, efficiency, and fuel-use standards set forth by the Federal Energy Regulatory Commission (FERC) pursuant to PURPA (The Public Utility Regulatory Policies Act of 1978). QFs include both cogenerator and small power producer facilities.

R

REAL TIME (Purchase or Sale) – The amount of energy, measured in MWhs supplied or received by the control area operator to balance a utility's load and supply.

REAL TIME MARKET (RTM) – The spot market conducted by the CAISO using SCUC and SCED in the real-time, after the HASP is completed, which includes the RTUC, STUC and the RTD for the purpose of unit commitment, ancillary service procurement, congestion management and energy procurement based on Supply Bids and CAISO forecast of CAISO demand.

REAL TIME PRICING – The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

REACTOR – A device in which a controlled nuclear chain reaction can be maintained, producing heat energy.

REGULATION – The service provided by generating units equipped and operating with automatic generation controls that enables the units to respond to the ISO's direct digital control signals to match real-time demand and resources, consistent with established operating criteria.

RELIABILITY – Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

RENEWABLE ENERGY – Resources that constantly renew themselves or that are regarded as practically inexhaustible. These include solar, wind, geothermal, hydro and wood. Although particular geothermal formations can be depleted, the natural heat in the earth is a virtually inexhaustible reserve of potential energy. Renewable resources also include some experimental or less-developed sources such as tidal power, sea currents and ocean thermal gradients.

RENEWABLE ENERGY CREDIT (REC) – A Renewable Energy Credit represents the environmental and renewable attributes of renewable electricity. A REC can be sold either "bundled" with the underlying energy or "unbundled", as a separate commodity from the energy itself, into a separate REC trading market.

RENEWABLE RESOURCES – Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

RESERVE – The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its users 1/4 needs.

RESERVE MARGIN – The differences between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

RESOURCE ADEQUACY (RA) – The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.

S

SCE (SOUTHERN CALIFORNIA EDISON COMPANY) – An electric utility serving the southern California region.

SDG&E (SAN DIEGO GAS & ELECTRIC) – An electric and natural gas utility serving the San Diego, California, region.

SCHEDULING COORDINATOR – Scheduling Coordinators (SCs) submit bids and schedules in CAISO markets and provide settlement-quality meter data to the CAISO. Scheduling Coordinators also:

- Assume financial responsibility for all schedules, ancillary service awards and dispatch instructions issued in the CAISO markets.
- Maintain a year-round, 24-hour scheduling center.
- Respond to dispatch instructions.

SEASONAL EXCHANGE – Electric energy, capacity, or ancillary services or transmission exchanged between counterparties measured in MWs or MWhs that is agreed to be supplied during one season or set of months in exchange for receiving an amount in another season or set of months. Dollars may or may not be exchanged in such a transaction.

SELF-GENERATION – A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

SERVICE AREA – The geographical territory served by a utility.

SETTLEMENT – The process of financial settlement for products and services purchased and sold. Each settlement involves a price and quantity. The ISO may perform settlement functions.

SITE – Any location on which a facility is constructed or is proposed to be constructed.

SMALL POWER PRODUCER – Refers to a producer that generates at least 75% of its energy from renewable sources.

SPINNING RESERVE – The portion of unloaded synchronized generating capacity, controlled by the ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

SPOT MARKET – A market in which transactions take place at most one day ahead of scheduled delivery.

SPOT NATURAL GAS (Physical Supply) – Purchases/sales/exchanges of physical natural gas for terms less than one month.

SPOT PRICE – The price for spot transactions.

STRANDED COSTS – Costs incurred by a utility which may not be recoverable under market-based retail competition. Costs incurred by a utility which may not be recoverable under market-based retail competition.

SUBSTATION – A facility that steps up or steps down the voltage in utility power lines. Voltage is stepped up where power is sent through long-distance transmission lines. It is stepped down where the power is to enter local distribution lines.

SUPPLIER – A person or corporation, generator, broker, marketer, aggregator or any other entity, that sells electricity to customers, using the transmission or distribution facilities of an electric distribution company.

SUPPLY BID – A bid indicating a price at which a seller is prepared to sell energy or ancillary services.

SUPPLY-SIDE – Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load though energy efficiency measures or on-site generation on the customer side of the meter.

SYSTEM – A combination of equipment and/or controls, accessories, interconnecting means and terminal elements by which energy is transformed to perform a specific function, such as climate control, service water heating, or lighting.

T

TEMPERATURE – Degree of hotness or coldness measured on one of several arbitrary scales based on some observable phenomenon (such as the expansion).

TOLLING AGREEMENT – An agreement to provide (receive) gas in exchange for receiving (providing) electricity.

TRANSITION COSTS – Stranded costs which are charged to utility customers through some type of fee or surcharge after the assets are sold or separated from the vertically-integrated utility.

TRANSMISSION – Transporting bulk power over long distances.

TRANSMISSION AND DISTRIBUTION (T&D) LOSSES – Electric energy or capacity that is wasted in the normal operation of a power system. Some kilowatt-hours are lost in the form of waste heat in electrical apparatus such as substation transformers. Line losses are kilowatts or kilowatt-hours lost in transmission and distribution of electricity.

TRANSMISSION AND DISTRIBUTION (T&D) SYSTEM – An interconnected group of electric transmission lines and associated equipment for the movement or transfer or electric energy in bulk between points of supply and points at which it is transformed for delivery to the ultimate customers.

TRANSMISSION LINES – Heavy wires that carry large amounts of electricity over long distances from a generating station to places where electricity is needed. Transmission lines are held high above the ground on tall towers called transmission towers.

U

U.S. DEPARTMENT OF ENERGY (DOE) – The DOE manages programs of research, development and commercialization for various energy technologies, and associated environmental, regulatory and defense programs. DOE announces energy policies and acts as a principal advisor to the President on energy matters.

UNCERTAINTIES – Uncertainties are factors over which the utility has little or no foreknowledge, and include load growth, fuel prices, or regulatory changes. Uncertainties are modeled in a probabilistic manner. However, in the Detailed Workbook, you may find it is more convenient to treat uncertainties as “unknown but bounded” variables without assuming a probabilistic structure. A specified uncertainty is a specific value taken on by an uncertainty factor (e.g., 3 percent per year for load growth). A future uncertainty is a combination of specified uncertainties (e.g., 3 percent per year load growth, 1 percent per year real coal and oil price escalation, and 2.5 percent increase in housing starts).

UPGRADE – An increase in the rating or stated measure of generation or transfer capability.

UTILITY – A regulated entity which exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, “utility” refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.

UTILITY-OWNED GENERATION – Resources owned by an investor-owned utility. Does not include resources that may be under contract or otherwise available to utilities, such as DWR contracts.

V

VARIABLE COSTS – The cost associated with fuel cost and variable operations and maintenance costs.

W

WEATHER TRIGGERED OPTIONS – A method for managing temperature and other weather forecast risks.

WHOLESALE POWER MARKET – The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

X

No entries for the letter X.

Y

No entries for the letter Y.

Z

No entries for the letter Z.

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