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Admin. Law Judge	:	Kelly A. Hymes
ORA Project Mgr.	:	Candace Choe
ORA Witnesses	:	Various

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY ON PACIFIC GAS AND ELECTRIC COMPANY APPLICATION FOR COMPLIANCE REVIEW OF UTILITY OWNED GENERATION OPERATIONS, ELECTRIC ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES, CONTRACT ADMINISTRATION, ECONOMIC DISPATCH OF ELECTRIC RESOURCES, UTILITY RETAINED GENERATION FUEL PROCUREMENT, AND OTHER ACTIVITIES FOR THE PERIOD JANUARY 1 THROUGH DECEMBER 31, 2015 (U 39 E)

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CHAPTER 1 EXECUTIVE SUMMARY

(Witness: Candace Choe)

I. EXECUTIVE SUMMARY

This testimony presents the Office of Ratepayer Advocates' (ORA) review of Pacific Gas and Electric Company's (PG&E) Energy Resource Recovery Account (ERRA) Compliance Application for the period from January 1, 2015 through December 31, 2015 (Record Period). PG&E filed its annual ERRA compliance application pursuant to Decision (D.) 02-10-062. In that Decision, the California Public Utilities Commission (Commission or CPUC) required certain utility procurement activities to be reviewed annually in the ERRA proceedings.

Pursuant to D.02-10-062, D.02-12-074 and California Public Utilities Code (PU Code) § 454.5(d)(3), the purpose of the ERRA is to record and recover power costs and ensure timely recovery of procurement costs incurred related to an investor-owned utilities' (IOUs) approved procurement plan.[1] PU Code § 454.5(d)(3) allows the Commission to establish balancing accounts to track the differences between recorded revenues and costs incurred related to the approved procurement plan.[2]

PG&E filed its ERRA compliance application on February 29, 2016 requesting Commission approval for costs associated with activities that occurred during the 2015 Record Period. The scope of ORA's review of PG&E's application includes a review of utility-owned generation (UOG) operations, fuel expenses and procurement, contract administration, least-cost dispatch (LCD), demand response, greenhouse gas compliance instrument procurement, and an audit of balancing account entries. In addition, ORA looked at other ERRA issues summarized below.

In this testimony ORA presents its analyses and recommendations associated with PG&E's requests. This testimony focuses exclusively on the 2015 Record Period and is based on ORA's analysis of information submitted by PG&E that includes, but is not limited to:

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[1] D.02-10-062, Finding of Fact (FOF) 23 and 26, pp. 71 – 72.

[2] PUC Code §454.5(d)(3) states: "The commission shall establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan. The commission shall review the power procurement balancing accounts, not less than semiannually, and shall adjust rates or order refunds, as necessary, to promptly amortize a balancing account, according to a schedule determined by the commission."

PG&E's testimony and workpapers submitted with its application, responses to data requests, meet-and-confer notes, and field-visit presentations.

The issues that ORA reviewed for the 2015 Record Period are listed in the table below and summarized in this chapter. For those issues or topic areas for which no testimony is filed, ORA does not have any recommendations or disallowances. The qualifications of ORA's witnesses and their testimony declarations are contained in Appendix A of this testimony.

List of ORA Witnesses and Respective Chapters

Chapter	Description	Witness
1	Executive Summary	Candace Choe
2	Least-Cost Dispatch And Economically-Triggered Demand Response	Mea Halperin
3	Utility-Owned Generation - Hydroelectric	Michael Yeo
4	Utility-Owned Generation – Fossil And Other Generation	Michael Yeo
5	Costs Incurred And Recorded In The Diablo Canyon Seismic Studies Balancing Account	Brian Lui
6	Generation Fuel Costs And Electric Portfolio Hedging	Monica Weaver
7	Greenhouse Gas Compliance: Procurement of Compliance Instruments and Greenhouse Gas Costs	Ayat Osman, Ph.D.
8	Contract Administration	Mea Halperin
9	Costs Incurred And Recorded In The Green Tariff Shared Renewables Memorandum Account	Brian Lui Monica Weaver
10	Energy Resource Recovery Account	Brian Lui Monica Weaver
11	Cost Recovery And Revenue Requirements	Brian Lui

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

The following summary provides an overview of each chapter presented and sponsored by the witnesses for the 2015 Record Period. This summary is provided strictly for the reader's convenience.

1. **Executive Summary -** (Candace Choe)

2. **Least-Cost Dispatch And Economically-Triggered Demand Response -** (Mea Halperin)

ORA has no recommendations for a disallowance in this area of the application. However, ORA recommends that the Commission should:

- Order PG&E to undergo an independent review, by an outside party, of its processes for forecasting day-ahead load and prices, including an evaluation of whether PG&E revises and updates its strategies based on above-normal deviations;
- Order PG&E to continue to monitor and assess its thermal resource workflow and business practices to prevent future errors that may have large cost impacts;
- Order PG&E's testimony to include further explanation, and quantitative calculations, of renewable resource opportunity costs, by type (e.g. wind, solar, etc.);
- Order PG&E's testimony to include explanations of energy curtailment, such as instances when it is necessary, how the economic decision is made to curtail a resource, the business process for curtailing a resource, and any quantitative metrics associated with this process; and
- Order PG&E to continue to evaluate its demand response opportunity cost metrics to ensure that it maximizes the value of these programs.

3. **Utility-Owned Generation – Hydroelectric** (Michael Yeo)

ORA recommends that the Commission:

- Disallow cost recovery of $19,268 in PG&E's ERRA Balancing Account for the 2015 Record Period because of the April 5, 2015 Helms Pumped Storage Facility Unit 2 outage; and
- Order PG&E to evaluate all hydroelectric facilities' Instrumentation and Controls (I&C) devices and list those that do not provide the correct indications of equipment operations, and to develop a plan of correcting those deficiencies, subject to cost-effectiveness analyses.

4. **Utility-Owned Generation – Fossil And Other Generation** (Michael Yeo)

ORA recommends that the Commission:

- Disallow cost recovery of $1,284,182 in PG&E's ERRA Balancing Account for the 2015 Record Period because PG&E was responsible for the unavailability of the Colusa Generating Station for various dates in October 2015 due to the failure of the attemperator piping;
- Order PG&E to report on the status of the corrective actions to be performed at the Colusa Generating Station as a result of the October 2015 power disruption events. The status report is to be filed in the 2017 ERRA application for the 2016 Record Period; and
- Order PG&E to evaluate Wärtsilä's quality control programs especially its corrective action plan commitments, as identified in Attachment 4.2, as result of the July 31, 2015 Humboldt Bay Generating Station outage.

5. Costs Incurred And Recorded in the Diablo Canyon Seismic Studies Balancing Account (Brian Lui)

ORA has no recommendation or disallowance in this area of the application.

6. Generation Fuel Costs And Electric Portfolio Hedging (Monica Weaver)

ORA has no recommendations for a disallowance in this area of the application. However, ORA recommends that the Commission order PG&E to submit the results of an external audit of STARS Alliance to ORA and the Commission once completed or for PG&E to include the audit review in the 2016 ERRA Record Period.

7. Greenhouse Gas Compliance: Procurement of Compliance Instruments and Greenhouse Gas Costs (Ayat Osman, Ph.D.)

ORA recommends that the Commission:

- Disallow a cost recovery of [redacted] in PG&E's ERRA Greenhouse Gas (GHG) subaccount (ERRA Tariff Line Item 5.ah) because PG&E did not provide the calculations of its Direct GHG emissions (emissions resulting from energy procured from PG&E's owned-facilities, tolling agreements, qualifying facility contracts, and imports). PG&E did not provide sufficient details on how it derived its average weighted costs used in the calculation of Direct GHG costs.
- Disallow a cost recovery of [redacted] in estimated Indirect GHG costs embedded in energy purchases from contracts ([redacted] of which are associated with contract purchases that might not include specific provision for settlement of GHG costs, and [redacted] of which are associated with contract purchases with financial settlement with specific GHG costs provisions). PG&E did not provide the calculations of the

estimated GHG emissions from energy procured from these contracts. PG&E did not provide sufficient explanation to substantiate the calculations of Indirect GHG costs related to these contracts, and how these costs correlate to the costs reported under PG&E's three ERRA accounts (Tariff Lines 5.ae, 5.n, and 5.o).

- PG&E should provide the Commission with verifiable information for the Commission and interested parties to ensure that it has complied with Commission and state policies and administered its program prudently in a cost-effective manner, specifically:
  - Calculations of Direct GHG emissions from its procured energy;
  - Calculations of Indirect GHG emissions from its procured energy from market and contract purchases;
  - Methodologies used to calculate Direct and Indirect GHG costs in sufficient details, including verifiable references; and
  - Supportive data to show how PG&E operated and managed its GHG program prudently in a cost-effective manner.

8. Contract Administration (Mea Halperin)

ORA has no objections to PG&E's request for approval of contract amendments resulting in an increase in the notional value of the underlying power purchase agreements. However, ORA recommends [redacted].

9. Costs Incurred And Recorded In The Green Tariff Shared Renewables Memorandum Account (Brian Lui and Monica Weaver)

ORA has no recommendation or disallowance in this area of the application.

10. Energy Resource Recovery Account (Brian Lui and Monica Weaver)

ORA has no recommendation or disallowance in this area of the application.

11. Cost Recovery and Revenue Requirements (Brian Lui)

ORA has no recommendation or disallowance in this area of the application.

CHAPTER 2 LEAST-COST DISPATCH AND ECONOMICALLY – TRIGGERED DEMAND RESPONSE

(Witness: Mea Halperin)

I. INTRODUCTION AND SUMMARY

This chapter of testimony reviews PG&E's dispatch and demand response (DR) activities for the Record Period from January 1, 2015 through December 31, 2015 and considers whether PG&E met the Commission's least-cost dispatch (LCD) standard. ORA examined Chapter 1 of PG&E's 2015 Energy Resource Recovery Account (ERRA) compliance testimony and submitted workpapers and analyzed data request responses, attended in-person and telephone meetings, and reviewed past ERRA testimony. Both PG&E's energy scheduling and demand response dispatch decisions were reviewed using the LCD standard of review, described below.

II. FINDINGS AND RECOMMENDATIONS

A. Assessment of Overall Forecasting Accuracy

- The Commission should order PG&E to undergo an independent review, by an outside party, of its processes for forecasting day-ahead load and prices, including an evaluation of whether PG&E revises and updates its strategies based on above-normal deviations.

B. Assessment of Management of Thermal Resources

- ORA finds PG&E's bid cost calculations, commitment decisions, and bidding practices for its thermal resources to be reasonable and an improvement over the last Record Period. PG&E must continue to monitor and assess its workflow and business practices to prevent future errors that may have large cost impacts.

C. Assessment of Management of Hydroelectric Resources

- ORA finds PG&E's management of its hydro resources, specifically, the calculation of opportunity costs and bidding in order for hydro resources to be dispatched during high energy value periods, to be reasonable. ORA cannot determine the accuracy or reasonableness of PG&E's hydro models until PG&E undergoes the independent review by an outside party, as approved in the previous Record Period's settlement agreement.

D. Assessment of Management of Renewable Resources

- PG&E's testimony should include further explanation, and quantitative calculations, of renewable resource opportunity costs, by type (e.g. wind, solar, etc.).
- PG&E's testimony should also include explanations of energy curtailment, such as instances when it is necessary, how the economic decision is made to curtail a resource, PG&E's business process for curtailing a resource, and any quantitative metrics associated with this process.

E. Essessment of Demand Response Programs

- ORA finds PG&E's overall management of its demand response programs to be an improvement over the previous Record Period. However, PG&E missed some opportunities for dispatching DR resources toward the end of the season and PG&E should continue to evaluate its opportunity cost metrics to ensure that it maximizes the value of these programs.

III. BACKGROUND

A. Standard of Conduct for Least-Cost Dispatch and Demand Response

The Commission's decision (D.) 02-10-062 instituted rules for the utilities' procurement responsibilities, established ERRA as the cost recovery mechanism for short-term procurement costs, and set minimum standards of behavior.[3] Standard of Conduct #4 (SOC4) states, "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[4]

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[3] D.02-10-062, p. 2.

[4] *Id.*, p. 52.

The subsequent decision (D.) 02-12-074 described the utilities' "up-front standard"[5] of least-cost dispatch as a guide for their short-term procurement plans as well as for the Commission to determine compliance. The decision elaborated upon SOC4:

> "Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services…[P]ure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations. The utility bears the burden of proving compliance with the standard set forth in its plan."[6]

In the settlement agreement resulting from PG&E's 2014 Record Period ERRA compliance proceeding, ORA and PG&E agreed that the Commission would review economically-dispatched demand response programs and hold PG&E to the least-cost dispatch standard of review described above.[7]

B. Clarification of LCD Expectations Following PG&E's 2010 Record Year and SCE's 2012 Record Year ERRA Compliance Proceedings

ORA's analysis of each investor-owned utility's (IOU) ERRA Record Year 2010 LCD testimony concluded that the utilities did not achieve least-cost dispatch and recommended disallowances for each utility. The Commission reviewed PG&E's LCD showing in Application (A.) 11-02-011 and issued D.13-10-041, stating that while the Commission would not approve the disallowance recommendation, the showing was below expectations.[8] The decision served to "ameliorate these shortcomings and provide specific direction to PG&E to improve its showings in the future."[9]

In order to improve LCD showings, the decision stated that in its 2014 ERRA compliance proceeding (and going forward), PG&E must include "precise numerical calculations that either demonstrate that PG&E achieved LCD during the Record Period, or

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[5] D.02-12-074, p. 54.

[6] *Id.*

[7] A.15-02-023 PG&E Settlement Proposal.

[8] D.13-10-041, p. 14-15.

[9] *Id.*, p. 15.

quantify the amount of overspending by PG&E."[10] Additionally, the decision directed the Commission's Energy Division to facilitate a workshop with all IOUs, wherein a set of proposed criteria would be developed for determining what constitutes least-cost dispatch compliance and the methodology required to demonstrate this compliance.[11]

Finally, in response to Southern California Edison Company's (SCE) Record Year 2012 ERRA reporting, ORA asserted that the utility did not provide adequate proof that it achieved LCD.[12] The Commission further clarified LCD responsibilities by issuing D.14-05-023 in which it established that, following the Market Redesign Technology Update (MRTU) in 2009, the California Independent System Operator (CAISO) is responsible for dispatching energy generation.[13] In other words, the regulated utilities are responsible for scheduling and bidding, but actual dispatch is performed by the CAISO.

C. Joint Proposal, Interim Ruling, and Final Decision for A.11-02-011

After the workshops, the utilities and subject matter experts proposed LCD criteria and methodologies and submitted them to the Commission in 2014 as the "Joint Proposal for the Demonstration of Least-cost Dispatch" (Joint Proposal).[14] ORA reviewed the proposal and provided recommendations, but the utilities and ORA disagreed on the format for reporting their Demand Response (DR) programs in ERRA compliance applications.[15]

The Commission issued the "Interim Ruling Providing Guidance for 2014 ERRA Compliance Proceedings," directing the utilities to comply with the uncontested portions of the Joint Proposal, which are as follows:

i.) The LCD Proposal shall be modified to include a background summary table in testimony.

ii.) The utilities shall use the 500 instead of 100 highest hourly Locational Marginal Prices in metric 4 of the Joint Proposal.

[10] *Id.*, p. 43.

[11] *Id.*, p. 25.

[12] D.14-05-023, p. 9.

[13] *Id.*, p. 19.

[14] D.15-05-006, p. 7.

[15] *Id.*, p. 7-11.

iii.) The summary reporting of daily self-commitment decisions shall be modified to show both "profit positions" and "loss provisions."

iv.) The utilities shall include a comparison of the accuracy of the utilities' forecast of prices in the day-ahead market compared to actual California Independent System Operator results.[16]

Finally, the Commission's Interim Ruling addressed the dispute between ORA and the utilities by ordering that the utilities show the "metrics for Demand Response" in the format proposed by ORA in ORA's response to the Joint Proposal.[17] The Commission issued a Proposed Decision on April 1, 2015, affirming the guidance and direction stated in the Interim Ruling.[18] This Decision was approved and finalized on May 7, 2015 and the standards were expanded to apply to all three utilities on December 3, 2015.[19]

IV. DISCUSSION AND ANALYSIS

ORA's analysis is organized to assess the following elements of PG&E's LCD and DR testimony: the accuracy of PG&E's overall forecasting accuracy and load bid calculations, dispatch of thermal resources, dispatch of hydro resources, and dispatch of DR programs.

A. Overall Forecasting Accuracy

i) Overview

In order to support its day-ahead market bidding, as well as to procure fuel to supply its thermal resources, PG&E conducts load and price forecasts. The load forecast is performed seven days in advance and is based on temperatures and actual hourly-updated load data. The price forecast is intended to reflect energy demand given market dynamics of supply, congestion, solar concentration, and transmission-constrained local area differences. This forecast also enables PG&E to evaluate the opportunity costs of use-limited dispatchable resources, such as hydroelectric powerhouses. Finally, during the optimization process, PG&E combines the load (supply) with the price (demand) forecasts

[16] *Id.*, p. 12.

[17] *Id.*

[18] *Id.*, p. 13-14.

[19] D.15-12-015.

to determine market clearing prices and the marginal cost of providing energy, which will inform the price at which a resource is bid into the CAISO's day-ahead market.[20]

PG&E's day-ahead forecast accuracy can be determined by comparing the load and price forecasts with the actual CAISO load and clearing price to get the average mean absolute percentage error (MAPE),[21] which is a measure of the forecast price deviation from the actual clearing price.[22] This information is provided in PG&E's testimony in its comparison of forecast and actual price and load for the 100 highest energy value days (ranked based on the total cost of the load cleared in the day-ahead market[23]) as well as for every day of the record year.[24] In addition to verifying forecast accuracy, this analysis provides insight into how well PG&E values its dispatchable resources to ensure that they are bid economically consistent with least-cost dispatch principles.

ii) Analysis

Among the 100 highest energy value days, the median MAPE was [redacted] and the mean value was [redacted].[25] According to PG&E's analysts, [redacted].[26] In order to verify this, ORA compared the MAPEs of the highest energy value days with all 365 days of 2015. For all days, the median MAPE was [redacted] and mean was [redacted]. Among the highest energy value days, [redacted] of MAPEs were [redacted], whereas for all days, [redacted] of MAPEs were [redacted] [redacted].[27] This is an improvement over the forecast accuracy in 2014, when mean deviation was [redacted] and the median value was [redacted].[28] Further, in the 2014 Record Period, the forecast deviated by [redacted] of the highest energy value

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[20] Trading floor tour during ORA site visit to PG&E office on March 16, 2016.

[21] Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.

[22] ORA Testimony for A.15-02-023, Chapter 2, p. 2-7.

[23] A.16-02-019, Chapter 1 Workpapers, LCD_6_Highest_Energy_Value_Days_and_Price_Forecast_ Summary.

[24] *Id.*, LCD_Workpaper_6_HighestEnergyValueDays.

[25] *Id.*

[26] Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.

[27] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_6_HighestEnergyValueDays.

[28] ORA Testimony for A.15-02-023, Chapter 2, p. 2-7.

days,[29] while in the 2015 Record Period, the highest MAPE value was [redacted] on the highest energy value days and [redacted] among all days of the year.[30]

ORA also notes that their recommendation for the previous ERRA Record Year included a request to provide a similar measure of price forecast variability for occasions when resources are self-committed.[31] PG&E did not provide this metric in its 2015 filing because it did not intentionally self-commit any resources for discretionary purposes such as air permitting limitations. The only occasions when a resource was self-committed were due to user error[32] so ORA cannot make any forecast comparisons.

iii) Summary and Recommendations

As noted, PG&E's forecast accuracy has improved from the previous year. Following the recommendations presented in 2014 record year's settlement, PG&E has provided the MAPE analysis for additional days of the year.[33] However, given the data that PG&E provided in this year's testimony, ORA is not able to verify the statement that a MAPE of [redacted] is normal and reasonable, or to assess how the forecast process changes or improves following a large deviation. ORA reiterates last year's recommendation:

- The Commission should order PG&E to undergo an independent review, by an outside party, of its processes for forecasting day-ahead load and prices,[34] including an evaluation of whether PG&E revises and updates its strategies based on above-normal deviations.

B. Load Bid Calculations

PG&E bids almost its entire load in the day-ahead market[35] and CAISO dispatches what does not clear in the real-time market. PG&E's load summary shows the total number of megawatt-hours (MWh) cleared each month in the day-ahead market and actual settled

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[29] *Id.*

[30] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_6_HighestEnergyValueDays.

[31] ORA Testimony for A.15-02-023, Chapter 2, p. 2-8.

[32] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_3_SelfCommitment.

[33] A.15-02-023, PG&E Settlement Proposal.

[34] ORA Testimony for A.15-02-023, Chapter 2, p. 2-8.

[35] A.16-02-019, Testimony, Chapter 1, Part B, Section 3, p. 1-14.

load. The difference indicates the amount of load scheduled in real-time. Based on these data, [redacted] of its total load was cleared in the day-ahead market, and each month [redacted] cleared in the real-time market.[36] This information provides a large-scale context for the efficacy of PG&E's load bidding strategy. A high proportion of load cleared in the day-ahead market indicates that PG&E has forecast and procured sufficient energy resources relative to consumer demand, and then appropriately calculated the value of its resources and translated these values into bids that would allow the resources to be economically dispatched.

C. Management of Thermal Resources

PG&E is required to bid its utility-retained and contracted thermal resources at their incremental (marginal) costs, subject to safety, regulatory, legal, operational, and financial requirements. PG&E is prohibited from taking any actions that result in a preference for its utility-retained thermal generation resources relative to those under contract with outside counterparties.[37]

i) Commitment Cost Decisions

PG&E is required to submit to CAISO its expected costs for starting up resources and running them at their minimum load, also known as commitment costs.[38] CAISO logs this information into its Master File, which is the record of all dispatchable resources' operating parameters and costs, and is used to inform CAISO's dispatch decisions. Utilities can submit proxy bids, which are decided by CAISO and can vary daily based on the cost of natural gas.[39] Alternately, if the utilities believe that the proxy bids do not adequately reflect the true costs of running a resource, like a facility's non-fuel related costs, they can

[36] *Id.*, Chapter 1 Workpapers, LCD_Workpaper_7_Load_Bid.

[37] *Id.*, Testimony, Chapter 1, Part B, Section 3, p. 1-14.

[38] ORA Testimony for A.15-02-023, Chapter 2, p. 2-9.

[39] Commitment costs are different from incremental bid costs in that they reflect only the cost of starting up and running a resource at its minimum operational load and are for informational purposes. Incremental bids are submitted to the CAISO market for each resource, each hour of every day, and reflect the marginal cost of energy for that resource. [redacted]
(A.16-02-019, Chapter 1 Workpapers, LCD_1_Commitment Cost Summary)

use the registered cost option. This allows the utilities to bid up to 1.5 times the proxy cost, but cannot be updated for 30 days.[40]

It is important for PG&E to choose the correct cost option, allowing its dispatchable resources to be bid as accurately as possible, and to fully capture the resource cost in the bid price. This allows CAISO to optimize the dispatch of all available energy resources based on the lowest possible cost, subject to other constraints.

At the end of 2014, CAISO updated its startup cost calculations to include major maintenance adder costs, which were responsible for some of the variable non-fuel related costs that would be captured in a registered cost bid. In 2015, in implementing this change, CAISO required resources using the registered cost to submit their major maintenance cost data and switch to the proxy cost option.[41] During this review period, PG&E continued to submit registered costs for some resources,[42] or would submit proxy bids at up to 1.25 times the cost, as is permitted under CAISO's Commitment Cost Enhancement initiative.[43]

PG&E's commitment cost decisions are detailed in its testimony and workpapers. Following CAISO's startup cost calculation update, PG&E reduced the number of registered cost bids it submitted to CAISO by a significant amount. In 2014, of [redacted]. In 2015, of [redacted].[44] The implication of this change is evident in the corresponding reduction in incorrect submissions. In 2014 PG&E made [redacted] incorrect submissions with a cost impact of [redacted], while in 2015 there were only [redacted] incorrect submissions due to [redacted] and had [redacted].[45] Among the reasons that registered costs were submitted, [redacted].[46] Given the reduction in

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[40] A.15-02-023, Testimony, Chapter 1, Part C, Section 1, p. 1-7.

[41] A.16-02-019, Testimony, Chapter 1, Part B, Section 6, p. 1-28.

[42] *Id*.

[43] Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.

[44] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_1_CommitmentCostDecisions, Table 1.1.5.

[45] *Id*.

[46] *Id.*, Table 1.2.

errors from 2014 to 2015, and the fact that there was no cost impact, ORA finds PG&E's commitment cost decisions to be reasonable.

ii) Incremental Bid Cost Calculations

PG&E calculates the incremental costs of its resources based on the variable costs associated with increasing or decreasing units of energy.[47] The components that go into these incremental costs include fuel prices, variable operations and maintenance costs, greenhouse gas adders, and transportation costs.[48] PG&E submitted [redacted] hourly bids to CAISO for its thermal resources, and [redacted] of those submitted bids had a variance between the calculated and correct bids of greater than [redacted]. Of these bid variances, [redacted] were due to either internal or external system errors and [redacted] were a result of user error.[49] Furthermore, two of these user errors resulted in an overall cost impact of [redacted].[50] The explanation given for the errors having cost implications was that [redacted].[51]

Although these errors have a small financial impact and make up a relatively small percentage of PG&E's overall bid calculations, it is an increase from last year's error rate and financial impact.[52] PG&E adapted its bidding process to catch further errors,[53] but PG&E must continue to monitor for systemic errors that may lead to higher costs.

iii) Bidding Activity

PG&E bids all available resources into the market at their incremental cost and if the Locational Marginal Price (LMP) (the price of energy at the node where the resource is sited) is greater than or equal to the bid price, CAISO will dispatch the resource. PG&E's

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[47] A.16-02-019, Testimony, Chapter 1, Section B, Part 3, p. 1-8.

[48] *Id.*, Chapter 1 Workpapers 2015 Fuel Price, VOM, Transport, GHG Rates by Resource.

[49] *Id.*, Testimony, Chapter 1, Part B, Section 6, p. 1-24.

[50] *Id.*, Chapter 1 Workpapers, LCD_Workpaper_2_BidCostCalculation.

[51] Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.

[52] ORA Testimony for A.15-02-023, Chapter 2, p. 2-12.

[53] Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.

testimony workpapers detail instances when resources were not bid into CAISO markets or, if bid, were not awarded despite the bid price falling below the LMP.

[redacted] These actions demonstrate that PG&E only bids resources when they are available, subject not only to outages, but also to environmental, contractual, and regulatory constraints. Additionally, there were three days in May when CAISO did not input Master File data for five of PG&E's resources, so PG&E was not able to bid them into the market system on these days.[55]

Among the [redacted] hourly bids that PG&E submitted to CAISO for its thermal resources, [redacted] were "flagged," meaning that they were not dispatched although the incremental bid cost was lower than the LMP. For all but two instances, the non-award was justifiable because the resource was providing ancillary services, was ramping down, was a multi-stage generator and was in the process of transitioning from one configuration to another, or all or part of the resource had an outage card,[56] limiting its available capacity.[57] In the other two instances, PG&E was not able to identify the reason for the non-award and submitted a Customer Inquiry, Dispute & Information (CIDI) Ticket to CAISO in order to find out.[58]

iv) Self-Commitment

In past years, PG&E reported an analysis of its self-commitment decisions for dispatchable thermal resources. PG&E may self-commit resources for discretionary

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[54] A.16-02-019, Chapter 1 Workpapers, LCD_2_Bid_Cost_Calculation_Summary.

[55] *Id.*

[56] PG&E submits bids for resources even during outage periods in order to prevent traders from forgetting to bid the resource once it is operational again. The outage card communicates to CAISO that although a bid has been submitted, the resource is either fully or partially unavailable. (Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016, confirmed through PG&E response to Data Request 12, Question 3.)

[57] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_2_BidCostCalculation.

[58] *Id.*

purposes, mainly to comply with annual air permitting limitations.[59] However, in the 2015 Record Period, PG&E's only self-commitment events came as a result of user error.[60] Two of its resources were self-committed for a total of 30 hours, and had an overall cost impact of [redacted].[61] In response to this, and to prevent future errors, PG&E updated its day-ahead bidding process to incorporate additional checks for incorrect self-commitment bids.[62] The cost impact of the self-commitment errors is de minimis and ORA will determine whether PG&E's 2016 Record Period reporting, to be filed in 2017, reflects the changes in the day-ahead bidding process.

v) Panoche Energy Center

In order to determine whether PG&E achieved least-cost dispatch, ORA analyzes bid cost calculations, submitted bid variances, and contractual compliance for all of its dispatchable resources. As an example of this analysis, ORA is focusing this section on the bidding and scheduling of Panoche Energy Center as a case study, and because this entity is a party in PG&E's 2015 ERRA proceeding. To ensure that PG&E is applying the same LCD practices to all of its resources across the board, ORA compared PG&E's management of Panoche with a sample of its other contracted thermal resources.

Panoche Energy Center is a 400 MW multi-unit gas-fired thermal generator located near Fresno, CA. Panoche's contract with PG&E is a tolling agreement, meaning that PG&E pays to supply the facility with the fuel needed to operate. The bid cost calculation for tolling agreements therefore includes the cost of fuel based on the natural gas market, the physical location of the facility on the gas pipeline, and, if applicable, any greenhouse gas (GHG) cost adders. Following the start of the carbon credit auction managed by the California Air Resources Board, PG&E entered into negotiations with entities that have tolling agreements with PG&E to determine which entity bears the burden of GHG cost adders.[63] According to PG&E, [redacted]

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[59] A.15-02-023, Chapter 1 Workpapers, LCD_3_Self_Commitment_Summary.

[60] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_3_SelfCommitment.

[61] *Id*.

[62] *Id,* Testimony, Chapter 1, Part B, Section 4, p.1-25.

[63] PG&E Response to Data Request 08, Question 10.

[redacted],[64] but this record year's LCD analysis is based on the 2015 contract's terms.

Only two of PG&E's workpapers list data by individual resource. There were no commitment cost errors for any of the tolling agreements, but the bid cost calculations showed more detail. There were [redacted] resources whose calculated hourly bids varied from the correct, or "clean," bid as determined by CAISO by at least [redacted]. Of these [redacted] bids, the resource having the greatest number of variances was [redacted]. (The second highest number is [redacted].) [redacted]

With respect to contractual and operational limitations, [redacted]

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[64] A.16-02-019, Testimony, Chapter 8, Part G, Section 9, p. 8-34.

[65] ORA Testimony, Chapter 2 Workpapers, Panoche Energy Center Comparison_Bid Variances.

[66] A.16-02-019, Chapter 1 Workpapers, Bid Sheets, PNCHEG_2_PL1X4.

[67] PG&E Response to Data Request 08, Question 2, Part e.

[68] A.16-02-019, Chapter 1 Workpapers, LCD_2_Bid_Cost_Calculation_Summary.

[redacted][69] In order to compare Panoche's total dispatch amount in MWh and cost of providing this energy relative to other facilities, ORA selected 10 other thermal resources[70] under tolling agreements with characteristics similar to Panoche. These resources are either located in the Central Valley (Panoche is situated near Fresno, CA), or are CAISO system resource adequacy resources (as is Panoche), and produced over 20,000 MWh of energy in 2015.[71] This analysis showed [redacted]

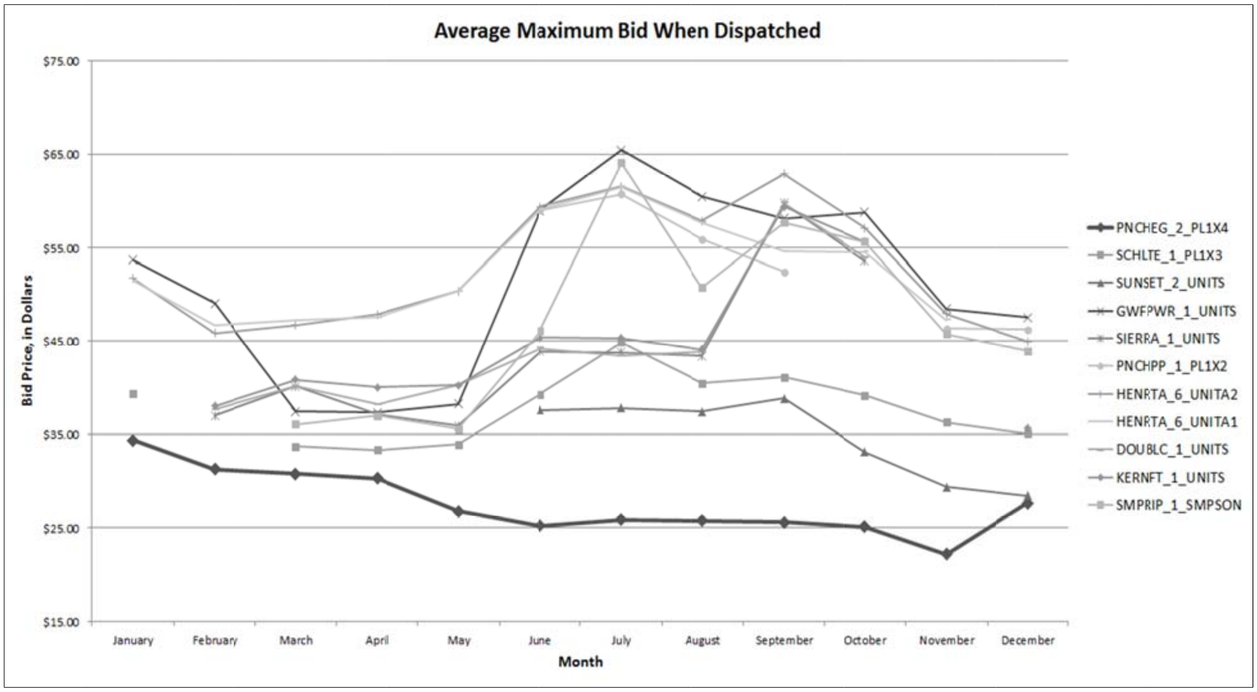
[69] ORA Testimony, Chapter 2 Workpapers, Panoche Energy Center Comparison, All Tolling.

[70] Resources selected for comparison were: [redacted]

[71] A.16-02-019, Chapter 1 Workpapers, Bid Sheets.

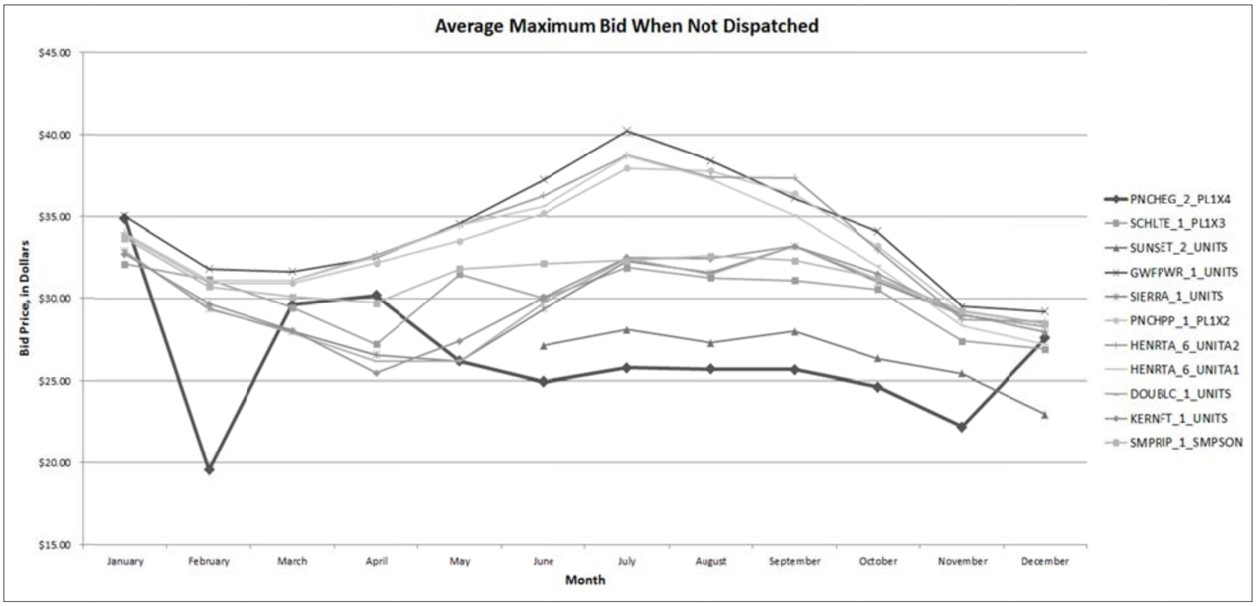
[72] ORA Testimony, Chapter 2 Workpapers, Panoche Energy Center Comparison, Dispatches.

[redacted]



Average Maximum Bid When Dispatched
$75.00
$65.00
$55.00
$45.00
$35.00
$25.00
$15.00
Bid Price, in Dollars
January
February
March
April
May
June
July
August
September
October
November
December
Month
PNCHEG_2_PL1X4
SCHLTE_1_PL1X3
SUNSET_2_UNITS
GWFPWR_1_UNITS
SIERRA_1_UNITS
PNCHPP_1_PL1X2
HENRTA_6_UNITA2
HENRTA_6_UNITA1
DOUBLC_1_UNITS
KERNFT_1_UNITS
SMPRIP_1_SMPSON

[redacted]



[redacted]

[redacted]

D. Management of Hydro Resources

i) Overview

Hydro generation is use-limited, meaning that because the amount of water is limited, hydroelectric generation may not be the most economic option at all times. In addition to the natural seasonal variability of water, 2015 was a drought year for California and therefore a low hydro year. While some hydro resources cannot be controlled at all, such as run-of-river resources, others can store water behind a dam and are bid into the CAISO markets at their incremental costs. Hydro resources do not have explicit fuel costs as thermal resources do, and so while the incremental cost of providing hydro power does not include fuel, utilities must consider the opportunity costs of utilizing the resource at a future time when it may be more valuable.

Least-cost dispatch of hydro resources must take into consideration the uncertainty of weather conditions such as the likelihood of precipitation and high temperatures, the future availability of water, and any potential operating constraints. Hydro resources have the highest value to customers when they are dispatched during high energy value periods and can offset or suppress high costs.[74] PG&E utilizes two hydro models (PLEXOS and TESS) for forecasting and optimizing hydropower generation.[75] In the previous Record Period's ERRA settlement, PG&E agreed to a one-time independent review of its hydro dispatch models and processes by an outside party.[76] Until this review takes place,[77] ORA cannot determine whether these models are reasonable or need any improvements.

ii) Analysis

PG&E's hydro resources were, on average, dispatched during [redacted] of the 500 highest energy value hours, determined by ranking the highest hourly LMP values.[78] This is an increase from the previous record year when hydro resources were dispatched during

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[74] A.16-02-019, Testimony, Chapter 1, Part B, Section 3, p. 1-18.

[75] *Id.,* Chapter 1 Workpapers, LCD_4_Hydro_Resources_Summary.

[76] A.15-02-023, PG&E Settlement Proposal.

[77] There is no set date for this review yet.

[78] A.16-02-019, Chapter 1 Workpapers, LCD_Workpaper_4_HydroSummary.

[redacted] of the 500 highest energy value hours.[79] This metric indicates that PG&E [redacted].

However, there are a few notable exceptions to this trend. For example, [redacted][80] [redacted]mped [redacted] [redacted][81] [redacted][82]

iii) Helms Pumped Storage Plant

PG&E's Helms Pumped Storage facility has a generation capacity of 1,212 megawatts (MW) and a pump capacity of 930 MW. Its three generators are located between two reservoirs, one of which is at a higher altitude than the other. Water from the lower-altitude afterbay can be pumped into the forebay for use at a time when hydro power is more economical to dispatch. However, due to the energy required to pump the water, it takes more than one megawatt-hour of energy to pump 1 MWh of energy for generation. Because of these inherent losses, PG&E must evaluate the opportunity costs not only of the hydro resource during generation time, but also, of the cost and time of pumping water.[83]

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[79] ORA Testimony for A.15-02-023, Chapter 2, p. 2-14.

[80] [redacted] (Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.)

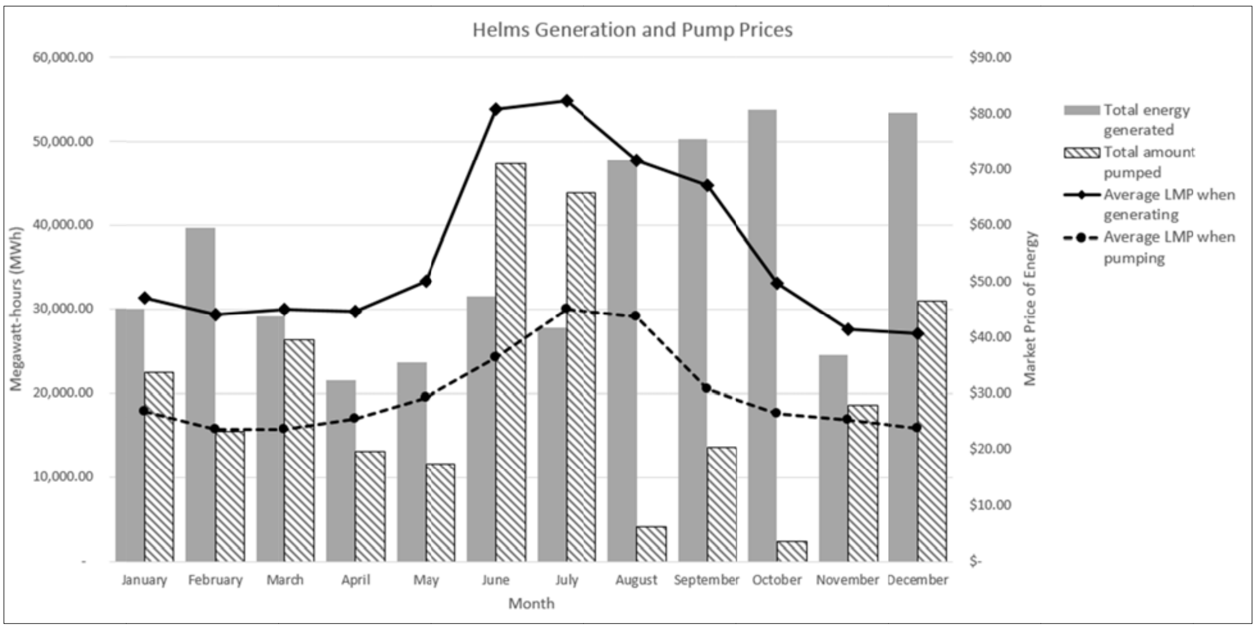
[81] [redacted]

[82] Presentation of LCD chapter and workpapers during ORA site visit to PG&E office on March 16, 2016.

[83] A.16-02-019, Testimony, Chapter 1, Part B, Section 3, p. 1-18.

Helms can provide the highest value while minimizing total cost to customers when energy is dispatched at times when market prices are high and water is pumped when market prices are low.[84] ORA's analysis of PG&E's bidding and scheduling of Helms energy and pumped storage determined that it did manage this resource according to least-cost principles. As Figure 3 below shows, [redacted].

[redacted][85]



iv) Summary and Recommendations

Overall, PG&E has demonstrated that it is bidding its hydro resources for dispatch according to LCD principles, during times when the price and value of energy is high. Additionally, PG&E demonstrated that according to LCD principles, it is bidding the Helms Pumped Storage facility for generation when the price and value of energy is high and pumping when prices are lower. ORA is awaiting the outcome of the independent review of the hydro models to determine whether they are reasonable or if PG&E could make any improvements.

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[84] *Id.*, p. 1-19.

[85] *Id.*, Chapter 1 Workpapers, Bid Sheets.

E. Management of Dispatchable Renewable Resources

PG&E states in its testimony that it both contracts with and owns renewable resources with economic bidding capabilities, and the opportunity costs of these resources are associated with contractual and operational constraints.[86] However, there is no further description or calculation of the opportunity costs associated with these renewable resources provided in any testimony or workpapers. As renewable resources become more sophisticated and "controllable," the Commission will need to review the utilities' bidding and scheduling practices for these resources as well. In addition to calculating the cost components making up the bid costs for the economic dispatch of renewable energy in the day-ahead market, PG&E evaluates market prices and opportunity costs associated with the curtailment of renewables. For example, sometimes the CAISO-reported net energy demand approaches the minimum must-offer threshold and increases the risk of overgeneration. Overgeneration can overburden distribution and transmission lines and lead to surges and outages. At these times, energy prices are often negative to provide a financial incentive for generators to "turn off" and reduce the amount of energy flowing into the grid. This scenario typically occurs midday when solar generation is at its peak.

By the time scheduling coordinators consider curtailing renewable resources, other thermal resources with flexible operating protocols have already been turned off, so renewables are the next type of energy resource that can be curtailed to prevent energy generation. However, to ensure compliance with California's Renewable Portfolio Standard, the utilities assess the opportunity cost of not generating the Renewable Energy Credits associated with renewable generation when determining their curtailment bids.

ORA submitted data requests and had conversations with PG&E's witnesses about individual resources and unique renewable issues such as curtailment and the future of energy storage,[87] but PG&E should provide more information regarding renewable resource opportunity cost and curtailment in future testimony. This information allows the

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[86] *Id.,* Testimony, Chapter 1, Part B, Section 3, p. 1-21.

[87] ORA recognizes that resources such as the Vaca Dixon Battery are in the testing phase and therefore are not being used in a significant enough capacity to draw any conclusions about how they may be used in the future. However, as battery storage technology develops, there will be economic considerations associated with bidding for generation and charging, much like with Helms hydro generation and pumping.

Commission to judge how PG&E achieves least-cost dispatch with respect to its entire dispatchable energy portfolio and how renewable contractual constraints, economic factors, and opportunity costs affect bid prices, and therefore electricity rates. In the 2015 Record Period there were no significant costs associated with renewable dispatch and no reported errors attributed to renewable resource bidding so ORA does not recommend any disallowances. ORA recommends that the Commission order:

- PG&E to include in its testimony further explanation, and quantitative calculations, of renewable resource opportunity costs, by type (e.g. wind, solar, etc.).
- PG&E to include in its testimony explanations of energy curtailment, such as instances when it is necessary, how the economic decision to curtail a resource is made, the business process for curtailing a resource, and any quantitative metrics associated with this process.

F. Management of Demand Response Programs

i) Overview

PG&E manages several types of DR programs, but the LCD chapter, and therefore ORA's analysis, focuses on DR resources with economic triggers. The most common economic trigger occurs when PG&E expects that the electricity required to meet energy demand will be supplied by generating facilities whose collective heat rates total at least 15,000 British thermal units per kilowatt-hour (Btu/kWh).[88] This is referred to as the Heat Rate trigger. PG&E tracks the daily natural gas market and CAISO's day-ahead market prices in order to forecast these economic triggers.[89]

Aggregator Managed Portfolio (AMP) resources can only be dispatched on a day-of basis, while the Capacity Bidding Program (CBP) can be dispatched on both a day-of and day-ahead basis. Each of these programs has a tariff with operational constraints. The AMP program is limited to [redacted] dispatch hours per DR season (May-October), while the CBP program is limited to 30 dispatch hours per month and 180 hours per season. Additionally, the AMP contract states that PG&E must call the program for a minimum of 4 consecutive

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[88] A.16-02-019, Testimony, Chapter 1, Part C, Section 3, p. 1-37.

[89] *Id.*

hours per dispatch, except during tests. Finally, PG&E must notify day-ahead CBP participants no later than 3:00 p.m. the day before it plans to dispatch the program. [90]

Furthermore, there are opportunity costs associated with DR dispatch. In addition to the opportunity cost of dispatching a resource at a future time, PG&E considers customer fatigue, or when a DR customer experiences frequent dispatch and, as a result, does not believe that the value of the dispatch outweighs the burden placed on their own operations and may be less likely to participate in the DR program in the future.[91] In order to avoid customer fatigue and subsequent customer attrition, per customer feedback, PG&E does not dispatch a DR resource more than three consecutive business days in a row.[92]

ii) Analysis

During the Record Period, PG&E [redacted] ious [redacted] Each of the 2015 events was triggered by the heat rate threshold.[94] During actual dispatch events, the average hourly price at the default load aggregation point (DLAP) – i.e. the cost of energy to consumers at the locations where DR resources were located – was [redacted], compared to the DLAP price of [redacted] at all of the times that the trigger conditions were forecast.[95] These values indicate that PG&E dispatched its DR resources during the hours with high energy value.

PG&E provided the data for all of the instances that the economic trigger was met but the DR resource was not dispatched. For the most part, the reason that resources were not dispatched was [redacted]

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[90] A.16-02-019, Testimony, Chapter 1, Part C, Section 3, p. 1-40-41.

[91] *Id.*, p. 1-42.

[92] *Id.*, p. 1-44.

[93] *Id.*, Table 1-7, p. 1-35.

[94] *Id.*, Attachment A.

[95] *Id.*, Errata.

[redacted][96] Overall, PG&E dispatched the CBP day-ahead and day-of programs for [redacted] of the annual maximum allowable 180 hours and the AMP program for [redacted] of the maximum allowable 80 hours.[97]

During the previous Record Period's ERRA review, PG&E and ORA agreed that PG&E would develop the quantitative metrics for calculating customer fatigue for use in future ERRA proceedings.[98] PG&E has not yet done so and therefore, for this Record Period, ORA cannot assess their reasonableness. Actual customer attrition data shows that [redacted] PG&E attributes these declines to the frequency of dispatch.[99]

There were 39 occasions between September 18 and October 15, 2015 (the end of the DR season) when the heat rate trigger was met but PG&E did not dispatch any DR resources. PG&E gave [redacted] ORA does not find this argument to be compelling. It is unlikely that this non-dispatch would prevent customer attrition. According to PG&E, "late season events are not a big driver of attrition. Customers usually either stop participating or opt out after the first few waves of back to back events which typically are early in the season."[101] Therefore, it appears that PG&E could have utilized its DR resources to further reduce load during late September and early October 2015 without violating any contracts or risking customer attrition.

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[96] *Id.*, Attachment A.

[97] PG&E Response to Data Request 08, Question 5.

[98] A.15-02-023, PG&E Settlement Proposal.

[99] PG&E Response to Data Request 16, Question 5.

[100] A.16-02-019, Testimony, Chapter 1, Attachment A.

[101] *Id.*, Question 6.

iii) Summary and Recommendations

As PG&E pointed out, and ORA confirmed, PG&E's DR dispatch during the 2015 record year was an improvement from the previous years. While it is not the objective of the DR program to use up all available hours, there were opportunities that PG&E could have taken at the end of the season to reduce customer load, conserve energy, and save ratepayers money. PG&E should continue to evaluate its opportunity cost metrics to ensure that it maximizes the value of the DR program.

V. CONCLUSION

Overall, ORA finds that PG&E managed its resources reasonably. Per the previous Record Period's settlement agreement, PG&E will order independent reviews of its forecasting methodology and hydro models to ensure that they are accurate and determine whether there is any need for refinement. PG&E is also developing quantitative opportunity cost metrics that will be useful for analyzing future demand response decisions. However, despite the fact that ORA previously requested that PG&E provide additional information about its economically dispatchable renewable resources, PG&E has yet to do so.[102] ORA is open to working with PG&E to determine the best format and content for this information.

[102] A.15-02-023, PG&E Settlement Proposal.

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_012-Q03		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_012-Q03		
Request Date:	April 6, 2016	Requester DR No.:	012
Date Sent:	April 20, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Alva Svoboda	Requester:	Mea Halperin

LEAST-COST DISPATCH (CHAPTER 1)

QUESTION 3

Does PG&E submit bids for resources even when the resources are experiencing outages?

ANSWER 3

For gas-fired thermal resources, PG&E as a practice creates bids regardless of availability. The CAISO outage management system ensures that no resource on an outage recognized by the CAISO will receive market awards even if bids are present. For other resources, bids are based on availability.

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_008-Q10		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_008-Q10		
Request Date:	March 24, 2016	Requester DR No.:	008
Date Sent:	April 7, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Maria Vanko Wilson	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 10

Please provide a list of PG&E's written contracts or tolling agreements where terms concerning compensation for GHG compliance costs were re-negotiated, and the outcomes of these resolutions and/or negotiations. Please provide executed contracts amendments and CPUC filings concerning contract amendments.

ANSWER 10

The attachments to this data response contains Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted]

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

	Count	Average Min	Average Max	Min val	Max val	User	ex. system	in. system	Percent
[redacted]									

Panoche Energy Center Comparison 3.2Bid variances

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_008-Q02		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_008-Q02-CONF		
Request Date:	March 24, 2016	Requester DR No.:	008
Date Sent:	April 7, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Mea Halperin

LEAST-COST DISPATCH (CHAPTER 1)

QUESTION 2

For Panoche Energy Center, please provide the following information:

a. Is this facility currently a System RA or Local Capacity Resource for the Fresno area?

b. If it is a System RA resource, is it being dispatched primarily to reach local Fresno area demand?

c. Does a facility's Local Capacity Resource or System RA designation determined how PG&E chooses to dispatch it when it is physically located in a geographically constrained area?

d. Has Panoche's RA designation changed at any time since the original PPA was signed? Please provide any historical documents that would indicate this change.

e. Did Panoche reach the exact, or approximate, maximum number of starts in 2015?

ANSWER 2

This data response contains Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

PG&E [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

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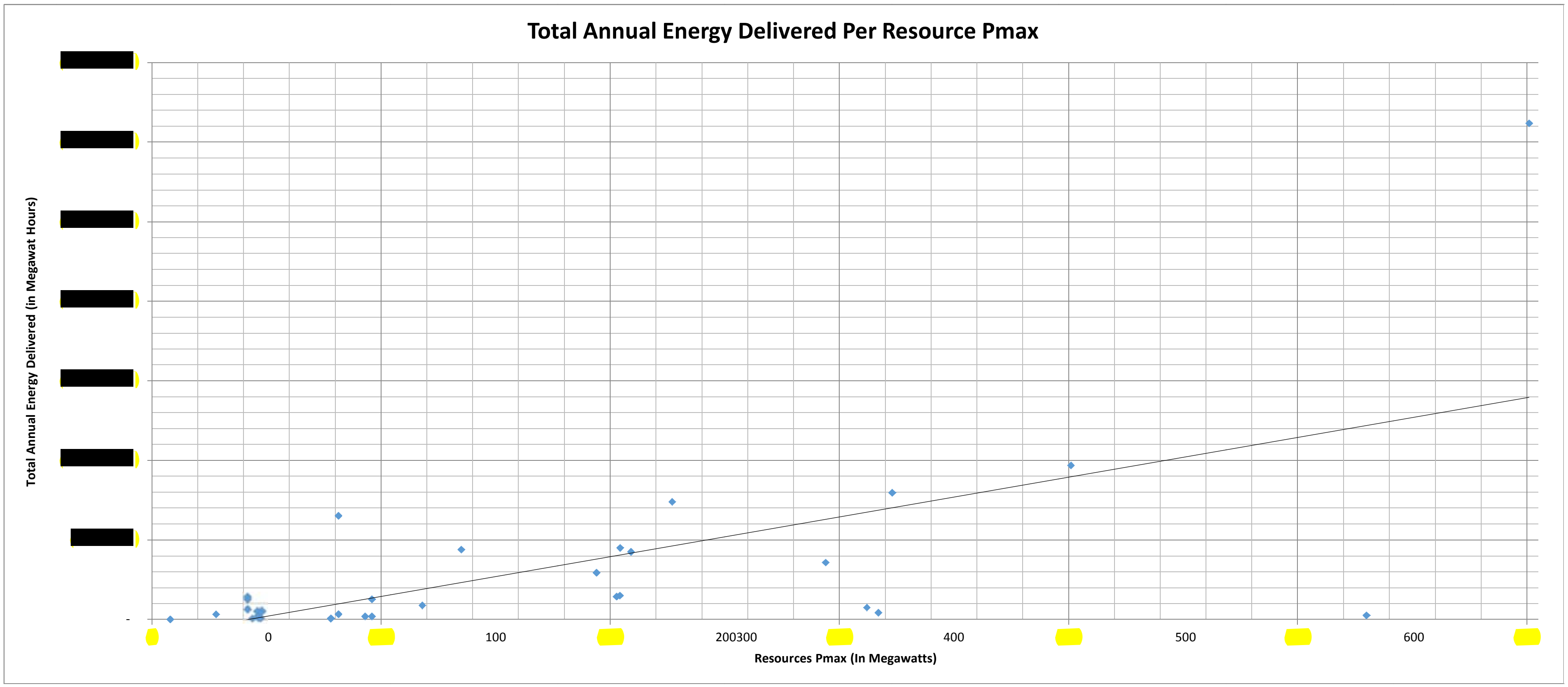


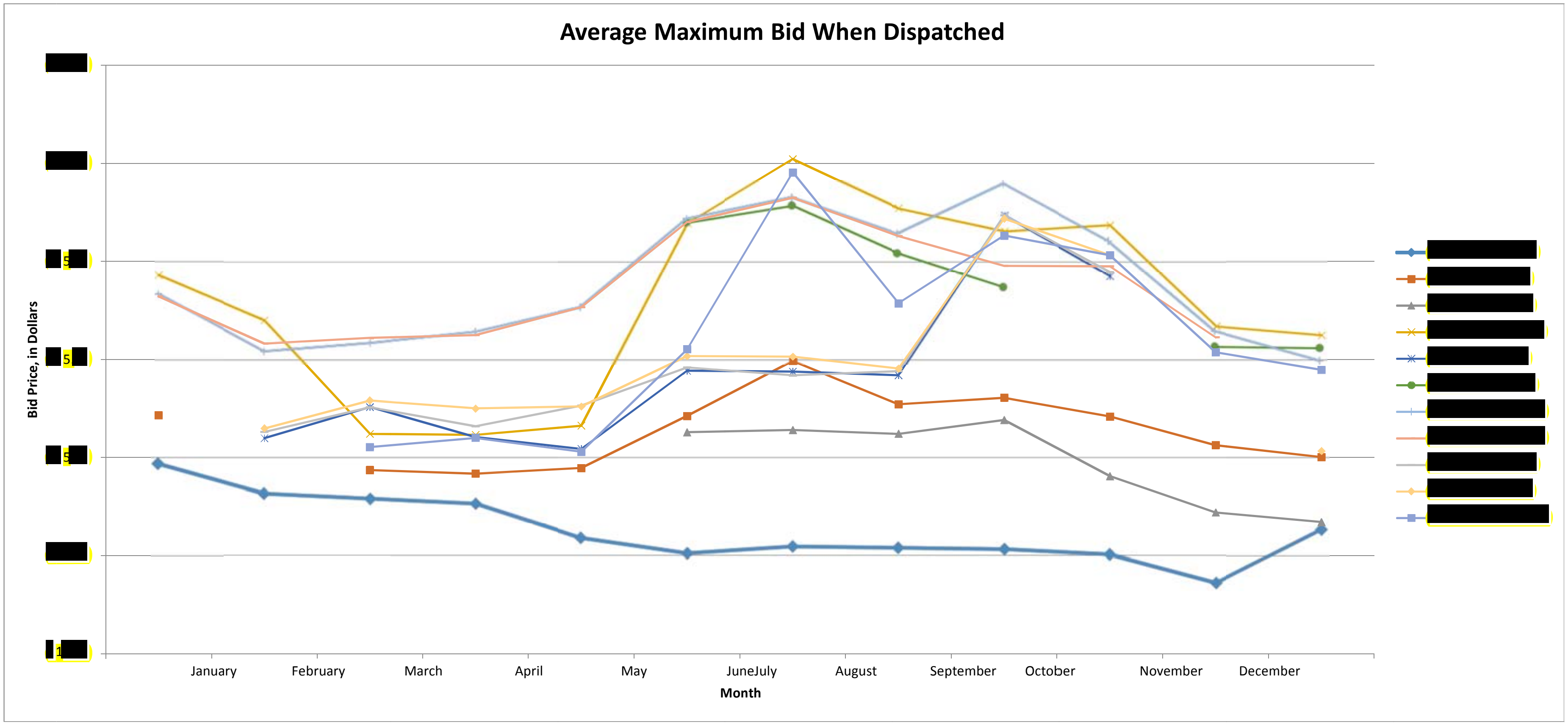
Panoche Energy Center Comparison 3.2All Tolling

[redacted]

Panoche Energy Center Comparison 3.2Dispatches

[redacted]

[redacted]


Average Maximum Bid When Dispatched
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Bid Price, in Dollars
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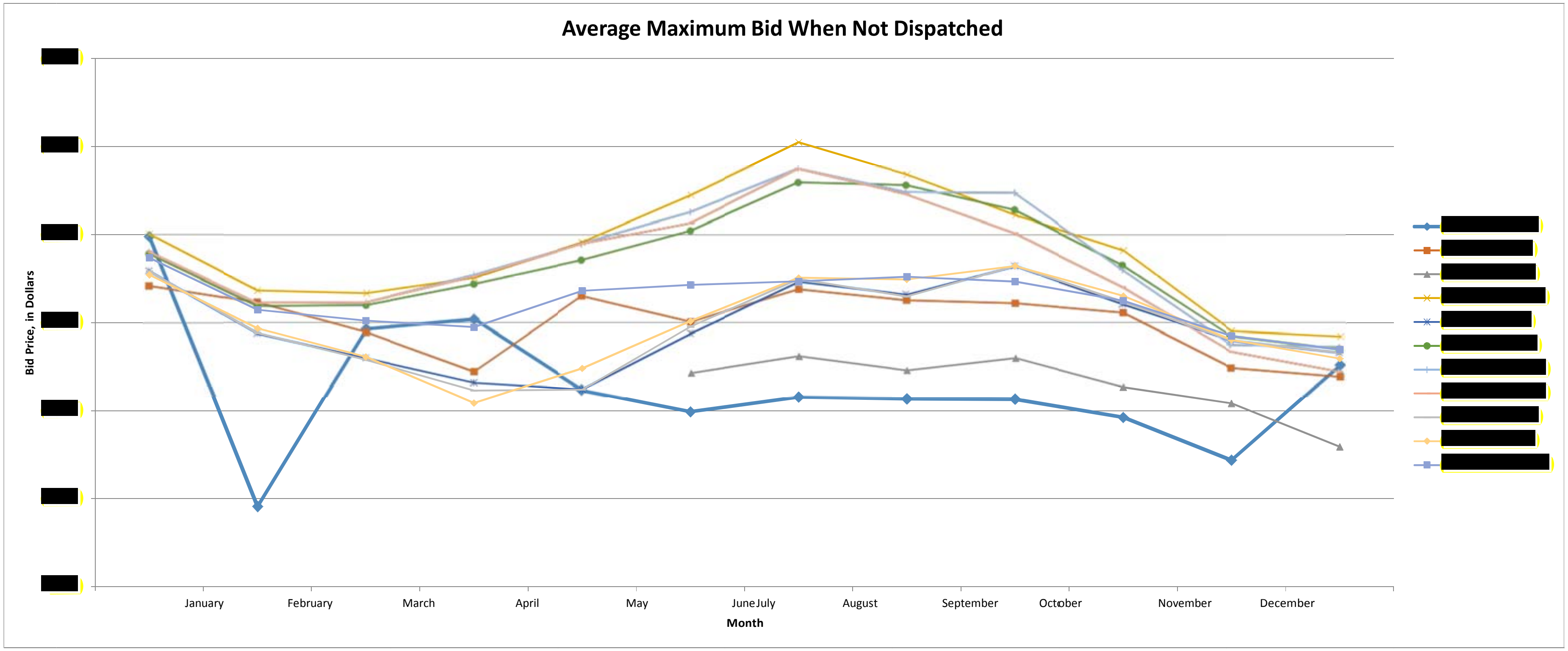

Average Maximum Bid When Not Dispatched
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Bid Price, in Dollars
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_016-Q05		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_016-Q05		
Request Date:	May 2, 2016	Requester DR No.:	016
Date Sent:	May 27, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Grant Brohard	Requester:	Mea Halperin

Economically-Triggered Demand Response (Chapter 1)

Question 5

How many demand response customers has PG&E **lost per record year** since the start of the AMP and CBP programs? Please provide the following information:

a. Attrition in terms of the number of

customers, b.Attrition in terms of megawatts,

c. Attrition in terms of dollars, and

d. Any other relevant evaluation criteria.

Answer 5

PG&E responds as follows:

[redacted]

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]			[redacted]			

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[redacted] [redacted]

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[redacted]

CHAPTER 3 - UTILITY-OWNED GENERATION – HYDROELECTRIC

(Witness: Michael Yeo)

I. INTRODUCTION AND RECOMMENDATIONS

This chapter addresses the operation and management of Pacific Gas and Electric Company's (PG&E) of its utility-owned hydroelectric (hydro) facilities, and outages that occurred at those facilities during the 2015 Record Period.

After reviewing PG&E's testimony and responses to ORA's data requests, ORA recommends that the Commission:

(a) disallow cost recovery of $19,268 in PG&E's ERRA Balancing Account for the 2015 Record Period because PG&E was responsible for the April 5, 2015 Helms Pumped Storage Facility Unit 2 outage; and

(b) order PG&E to list all hydro facilities' instrumentation and controls devices that do not indicate the correct operating conditions of equipment, and to develop a plan of correcting those deficiencies, subject to cost-effectiveness analyses. This recommendation is based on the fact that, in the April 5, 2015 Unit 2 outage, the control room indication showed that the bypass valve of the turbine shutoff valve was fully closed when it was not.

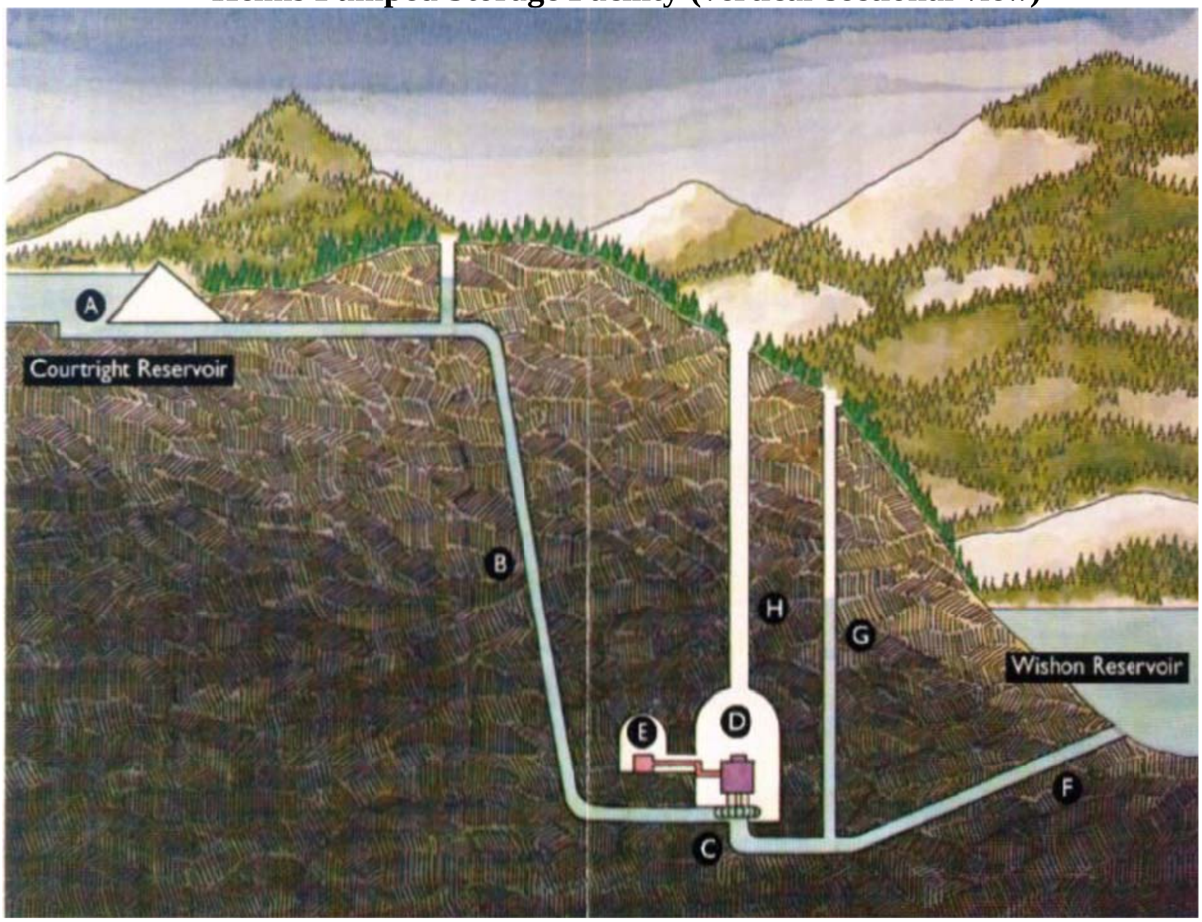
II. GENERATION FACILITIES

PG&E, in its testimony, states that its utility-owned hydroelectric portfolio consists of 67 hydro powerhouses, which are located on 16 rivers and four tributaries of the Sierra Nevada, Cascade and Coastal mountain ranges. For the 2015 Record Period, ORA reviewed the Helms Pumped Storage Facility (Helms).

HELMS PUMPED STORAGE FACILITY (Helms)

Helms, located in Fresno County's Sierra Nevada Mountains about 50 miles east of Fresno, is PG&E's only pumped storage powerhouse. Helms is a reservoir storage powerhouse, with three generators of 404 MW each, for a total installed capacity of 1,212 MW situated between an upper reservoir, Courtwright Lake, and lower reservoir, Lake Wishon.

Figure 3-1[103]
Helms Pumped Storage Facility (vertical-sectional view)



A-Courtright Reservoir, B-Supply Tunnel, C-Turbine, D-Generator, E-Transformer, F-Wishon Reservoir, G-Surge Chamber, H-Elevator

The three generators can be reversed to act as pumps with an approximate pumping capability of 318 MW for each pump. When water is released from the upper reservoir through the powerhouse turbines, each of the three units generates 404 MW, and discharges 3,300 cubic feet of water per second (CFS). In pumping mode at the full capacity of 318 MW, the three generators discharge 1,850 CFS. This difference in water usage between generating and pumping is a result of the differences in design efficiencies between the generate mode and the pump mode.[104]

[103] PG&E's Presentation Slides at Helms on April 28, 2016 by Steve Royall and Keith Heimbach.

[104] PG&E response to ORA DR #5.4.

PG&E filed Application (A,) 54450 on November 15, 1973 requesting a Certificate of Public Convenience and Necessity (CPCN) for the construction of Helms. The CPCN was granted in Decision (D.) 85910 on June 2, 1976. Helms was commissioned for service on June 30, 1984.[105]

In its testimony,[106] PG&E states that, during off-peak hours, when energy prices are lower, the pumping mode is utilized to pump water back up to Courtwright Lake to be reused during the next cycle. The ability to pump the water back up to the storage reservoir allows the water resource to be reused for generation during peak demand hours.

III. HELMS FORCED OUTAGE – April 5, 2015

PG&E, in its response to ORA Data Request (DR) # 5.5 and #5.8, explains that, when Helms is operating either in pumping or generating mode, the water pressure on the upstream and the downstream side of the 94½” [107] turbine shutoff valve (TSV) needs to be equalized prior to its opening. This difference in water pressure across the TSV is due to the difference in height of the water level between the Courtright Reservoir (upper reservoir), and the Wishon Reservoir (lower reservoir).

With this large differential pressure (several hundred pounds per square inch, depending on usage)[108] across the TSV, the force to open this large 94½” TSV is significant. Therefore, a bypass piping system known as the TSV bypass piping is utilized. Within the TSV bypass piping is a 10” valve (TSV bypass valve), which, when opened, allows water to flow into the bypass valve – and this flow equalizes the pressure across both the bypass valve and the TSV.[109] The TSV is then able to be opened with

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[105] PG&E’s Presentation Slide at Helms on April 28, 2016 by Steve Royall and Keith Heimbach.

[106] PG&E Prepared Testimony A.16-02-019, p. 2-4.

[107] PG&E’s Presentation Slide at Helms on April 28, 2016 by Keith Heimbach, Senior Manager, Power Generation.

[108] Information from PG&E plant staff at Helms on April 28, 2016.

[109] PG&E’s Presentation Slide at Helms on April 28, 2016 by Keith Heimbach, Senior Manager, Power Generation.

considerable less effort; once the TSV has been fully opened, the TSV bypass valve is subsequently closed.[110]

When the pumping or the generating mode is completed, the TSV is again closed.[111] With the TSV closed, the TSV once again experiences the pressure differential due to the difference in height of the water level between the upper and the lower reservoir.

Both the TSV and the TSV bypass valve are operated hydraulically.

The Unit 2 outage started on April 5, 2015 at 5:00 p.m. when it was forced out of service because the TSV bypass valve of Unit 2 failed to close fully.

In its response to ORA DR # 5.9, PG&E describes that, during the pump initiation, the operators noticed that the turbine spiral case pressurization took approximately ten minutes compared to a normal pressurization period of less than ten seconds. The unit then pumped as expected until dispatched to stop pumping. Following completion of the requested pumping operation, the operator noted that water could be heard passing through the TSV bypass valve despite indications that the valve was fully closed. An operator attempted to stroke the valve to help diagnose the problem when a loud bang was heard. The unit was then forced out of service to investigate the problem further by disassembling the TSV bypass valve.

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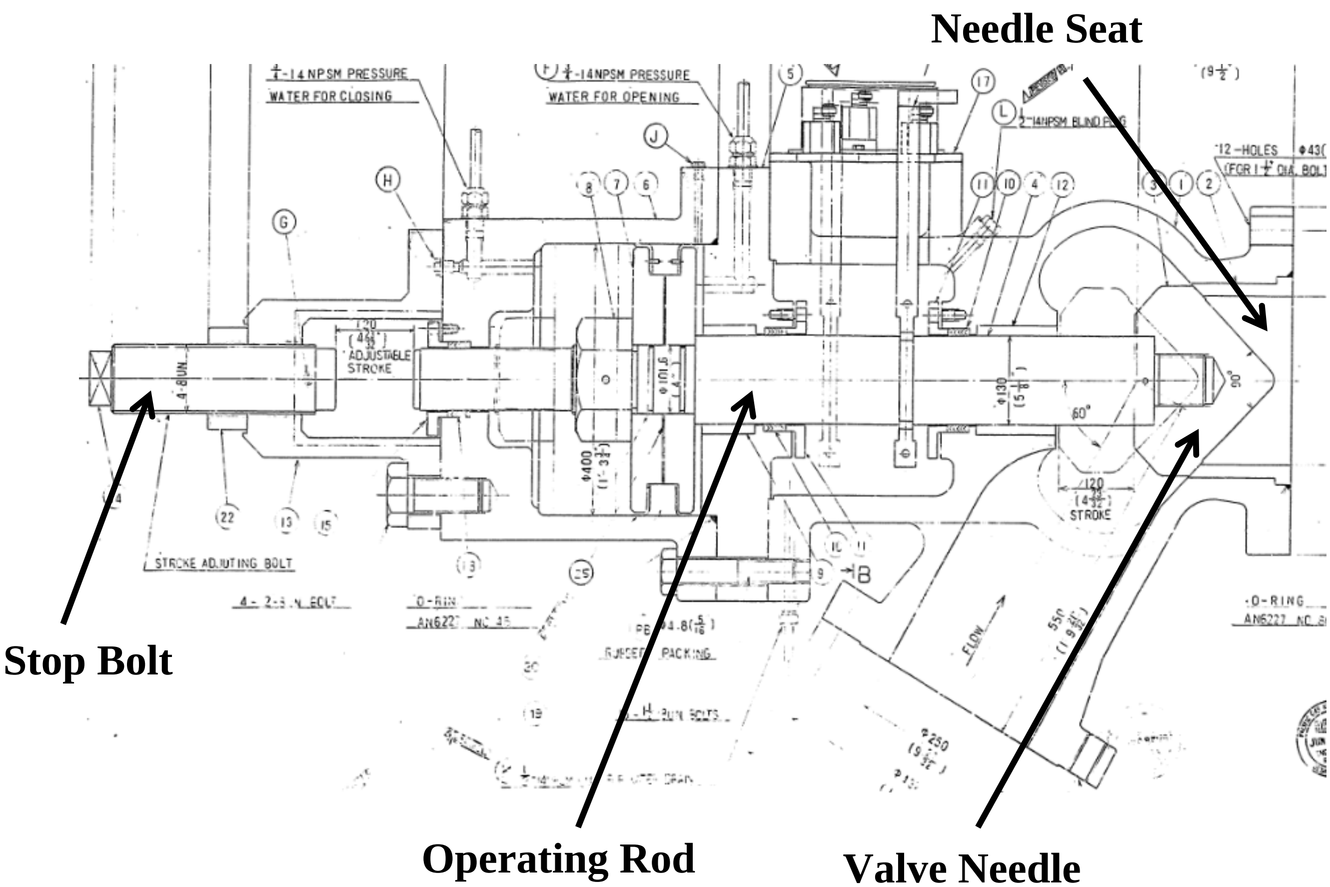
[110] Information from PG&E plant staff at Helms on April 28, 2016.

[111] *Id.*

Figure 3-2[112]
TSV Bypass Valve (cross-sectional view)



The purpose of each of the TSV bypass valve components is as follows:

a. valve needle – Connected to the operating rod, the valve needle controls water flow by moving closer to or further from the needle seat;

b. needle seat – Functions as a sealing surface with the valve needle;

c. operating rod – Connected to the valve needle, the operating rod moves the valve needle closer to or further from the needle seat; and

d. stop bolt. – Adjusts needle stroke by limiting the operating rod's movement in the open position.

[112] PG&E response to ORA DR #5.6.

PG&E, in its Direct Testimony,[113] stated that, upon removal of the Unit 2 TSV bypass valve for inspection, PG&E determined that the valve needle, needle seat, and operating rod were damaged due to separation of the needle from the operating rod. Upon further inspection, PG&E found the stop bolt for the operating rod to be out of parameter preventing it from stopping the operating rod as intended.

PG&E initiated two parallel responses to fix the problem:

i. As an interim solution to allow the unit to return to service promptly, PG&E, in its testimony, states that it fabricated a steel stop plate to provide the necessary stopping mechanism for the operating rod (see Figure 3-5). After installing the plate, PG&E tested the operation of the operating rod to ensure the needle was not making contact and putting pressure on the internal plate when the valve was at full open position. [114]

ii. Another solution[115] was to use the TSV bypass valve from another unit. As it happened, Unit 3 was on scheduled extended outage for the generator rotor replacement. PG&E then decided to install Unit 3's TSV bypass valve on unit 2. With this option, Unit 2 was returned to service a lot sooner. The reworked TSV bypass valve from Unit 2 was then installed in Unit 3. [116]

Unit 2 was returned to service on April 9, at 9:02 a.m.

PG&E, in its response to ORA DR #5.10, explains that the cause of the separation of the needle from the operating rod was attributable to an incorrectly adjusted stop bolt. Due to this incorrect adjustment, the opening force, created by the high pressure water, was causing the back of the valve needle to make contact with the valve body, ultimately shearing the operating rod at the base of the needle/operating rod interface. PG&E believes that the incorrect adjustment to the stop bolt dates back to 1984 when the plant was commissioned.

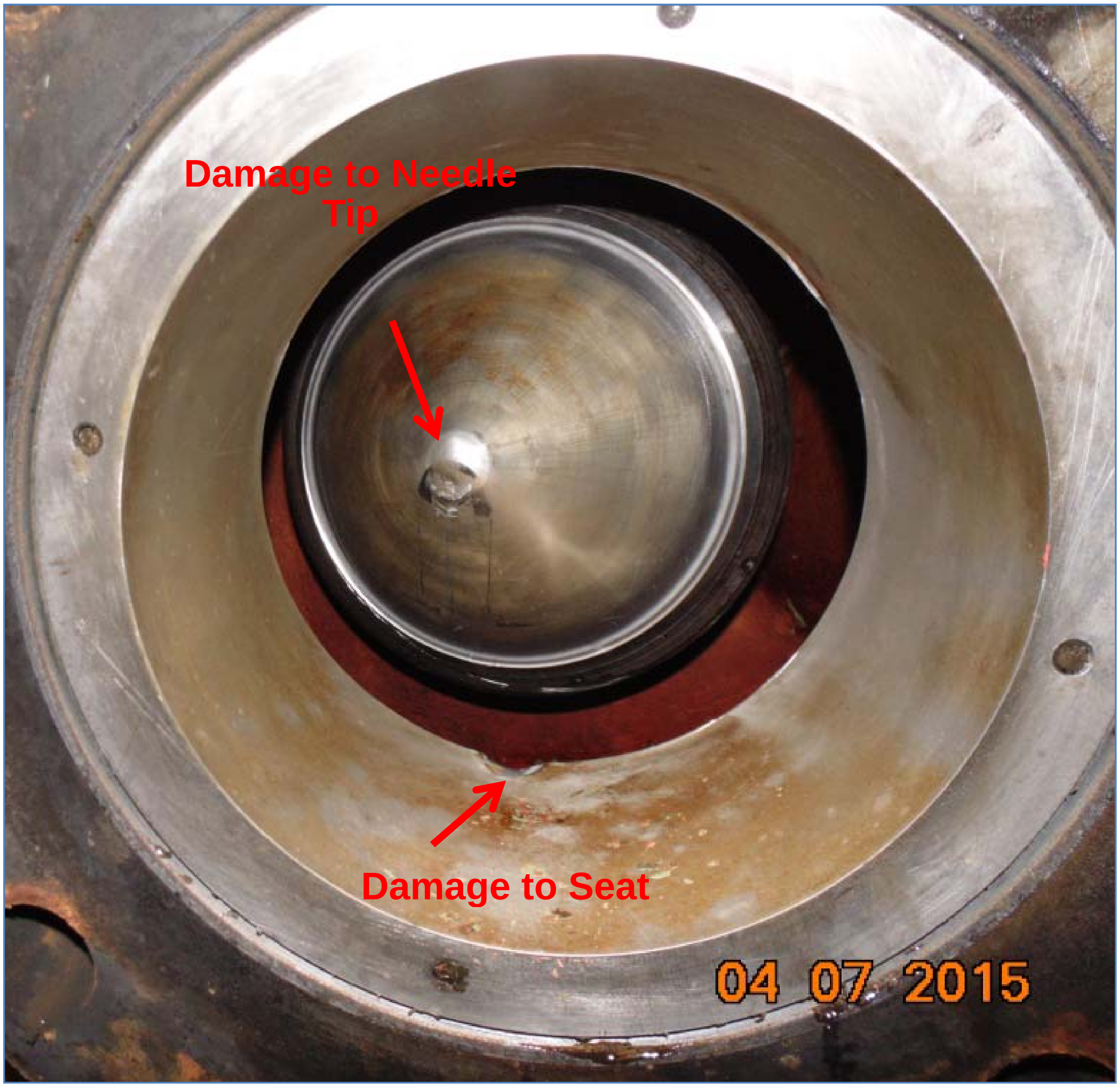
[113] PG&E Prepared Testimony A. 16-02-019, p. 2-23.

[114] *Id.*

[115] PG&E's Presentation Slide at Helms on April 28, 2016 by Keith Heimbach, Senior Manager, Power Generation.

[116] Information from PG&E plant staff at Helms on April 28, 2016.

Figure 3-3[117]
Damage to the TSV Bypass Valve needle and needle seat



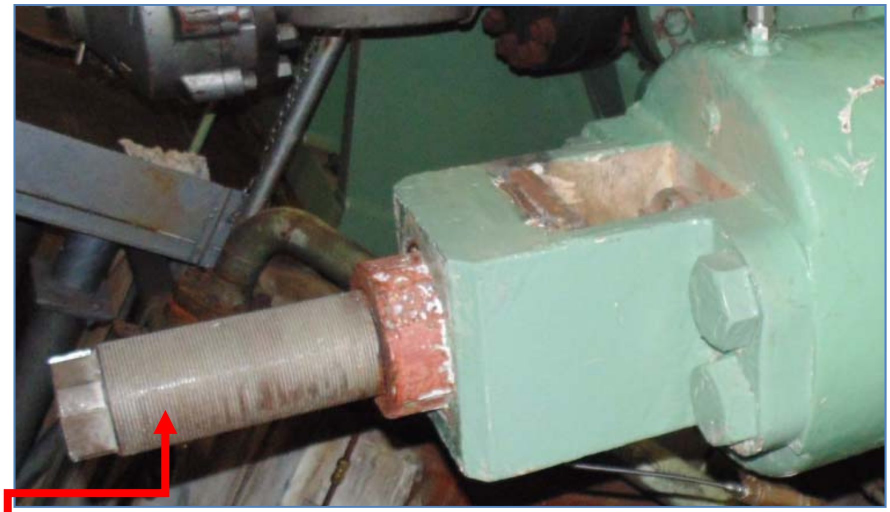
[117] PG&E response to ORA DR #5.11.

Figure 3-4[118]
Damage to the TSV Bypass Valve operating rod

Operating Rod/ Needle Interface Broke Cleanly Off.

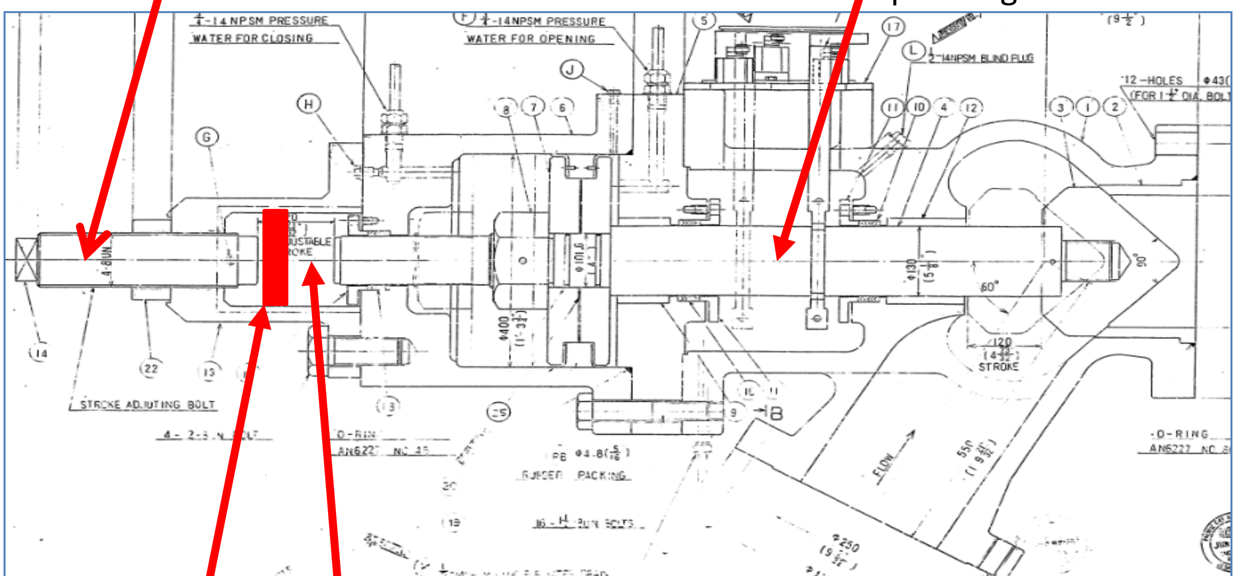
[118] PG&E response to ORA DR #5.11.

Figure 3-5[119]
TSV Bypass Valve Stop Bolt



The TSV Bypass Valve stop bolt was found to be in the retracted position and was frozen in place

Operating Rod



Steel Stop Plate -Interim Repair

When TSV bypass valve was fully open, the stop bolt was not contacting the operating rod.

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[119] PG&E response to ORA DR #5.11, #5.12 and #5.25.

In addition to PG&E's testimony and its responses to data request questions, ORA reviewed PG&E's *Event Report Details* document on the April 5, 2015 outage. PG&E, in its response to ORA DR # 5.10, explained that the two-page *Event Report Details* document was prepared instead of a Root Cause Analyses report because "*Root Cause Analyses are typically performed when the cause of the forced outage is not clearly understood. A Root Cause Analyses requires a significant investment of time and resources. In this case, the cause of the forced outage was very clear so PG&E did not consider doing a formal root cause analysis.*" PG&E stated in its response to ORA DR # 5.10 that the root cause of the problem was attributed to an incorrectly adjusted stop bolt, and "[*it*] *is believed that the incorrect adjustment to the stop bolt dated back to 1984 when the plant was commissioned.*"

ORA also visited the Helms Pumped Storage Facility on April 28, 2016, to observe the facility and the TSV Bypass Valve to understand the April 5, 2015 outage.

<u>Corrective Actions</u>

As stated previously, PG&E was able to correct the TSV bypass valve problem by using Unit 3's TSV bypass valve, and Unit 2 was promptly returned to service in less than four days. The defective Unit 2 TSV bypass valve and the stop bolt were refurbished, and the steel stop plate was removed; the refurbished work took 2½ weeks.[120] The reworked TSV bypass valve from Unit 2 was then installed in Unit 3.[121]

In its response to ORA DR # 5.33, PG&E states that it had also looked at the other TSV bypass valves in Unit 1 and 3, and found them to be in a similar condition as with the Unit 2 valve, and subsequently corrected the problem as well.

From the materials reviewed, there is no documented evidence that PG&E is planning to change how it intends to monitor, from the control room, the actual condition on the closure of the TSV bypass valve, such as modifying its existing instrumentation and controls (I&C) devices. As stated previously, the operator noted that his/her

[120] PG&E's Presentation Slide at Helms on April 28, 2016 by Keith Heimbach, Senior Manager, Power Generation.

[121] Information from PG&E plant staff at Helms on April 28, 2016.

indication showed that the TSV bypass valve was fully closed, and yet it was not. ORA contends that operators generally should know promptly the actual operating conditions of equipment so that they can take expeditious corrective actions, if needed, to avoid costly and avoidable outages.

Cost of Outage

In PG&E's response to ORA DR #5.18, it stated that the April 5, 2015 outage resulted in a cost to ratepayers of $19,268 in replacement power; this amount is the net between the actual replacement energy cost and the various CAISO charges, such as various imbalance energy costs, settlement costs and other costs. In addition, the direct PG&E cost of refurbishing each TSV bypass valve was $99,000.[122] The cost breakdown of this $99,000 is as follows:

Table 3-1

Direct PG&E Cost*

Line No.	Description	Amount
1	Labor	$4,100
2	Material	57,100
3	Contract	33,800
4	Other	4,000
5	Total	$99,000

* The above cost does not include the cost incurred while installing the temporary repair because PG&E did not separately track that cost.[123]

Therefore, the total cost of this outage from both replacement power and PG&E's direct cost is $118,268. PG&E adds that the above direct PG&E's direct cost of $99,000 is addressed through PG&E's General Rate Case (see Attachment 3.1).

IV. CONCLUSIONS AND RECOMMENDATIONS

Based on ORA's review of the other afore-mentioned documents and report, ORA determines that PG&E was responsible for the April 5, 2015 Unit 2 outage because

[122] PG&E's response to ORA DR #5.23.

[123] Ibid.

PG&E admitted that the cause of the outage was due to the incorrect adjustment of the stop bolt[124]. PG&E believes that the incorrect adjustment to the stop bolt dated back to 1984 when the plant was commissioned under the ownership of PG&E. The incorrect adjustment was also found, upon subsequent inspection by PG&E, in Unit 1 and Unit 3. It appears that PG&E, at the time of commissioning, did not perform a thorough review and inspection to detect and correct the mistakes.

In conclusion, ORA recommends that the Commission

(a) disallow a cost recovery of $19,268 in PG&E's ERRA Balancing Account for the 2015 Record Period because of the April 5, 2015 Helms Pumped Storage Facility Unit 2 outage; and

(b) order PG&E to evaluate all hydroelectric facilities' I&C devices and list those that do not provide the correct indications of equipment operations, and to develop a plan of correcting those deficiencies, subject to cost-effectiveness analyses. This recommendation is based on the fact that, in the April 5, 2015 Unit 2 outage, the control room indication showed that the bypass valve of the turbine shutoff valve was fully closed when it was not.

[124] PG&E's response to ORA DR #5.10.

Attachment 3.1

PG&E's Response to ORA Data Request #5.23 – Cost Recovery

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_005-Q23		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_005-Q23		
Request Date:	March 11, 2016	Requester DR No.:	005
Date Sent:	March 29, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Steve Royall	Requester:	Yakov Lasko

HELMS PUMPED STORAGE FACILITY (CHAPTER 2)

QUESTION 23

How much did it cost PG&E to replace the damaged parts? Please provide the cost breakdown (labor, materials, etc.) and workpapers. If there are numerous cost items less than $100,000, please group them in the appropriate categories.

ANSWER 23

PG&E objects to this request to the extent that it seeks information that is beyond the scope of issues in this proceeding. Operation and maintenance and capital costs are addressed through PG&E's General Rate Case.

Subject to this objection, PG&E responds as follows: PG&E did not separately track the cost of removing the Unit 2 TSV bypass valve; replacing it with the Unit 3 TSV bypass valve; and fabricating and installing a steel plate in the Unit 3 TSV bypass valve to provide the necessary stopping mechanism for the operating rod. However, PG&E separately tracked the cost to refurbish a TSV bypass valve. After the Unit 2 TSV bypass valve forced outage, PG&E refurbished each of the bypass valves on the three units at a cost of approximately $99,000 for each valve. The breakdown of the $99,000 is as follows:

TABLE 1
COST BREAKDOWN

Line No.	Description	Amount
1	PG&E Labor	$ 4,100
2	Contract	33,800
3	Materials	57,100
4	Other	4,000
5	Total	$ 99,000

Workpapers showing the detailed breakdown of the cost to refurbish the Helms Unit 1 TSV bypass valve are included in Attachment 1 to this data response (see Excel document, "ERRA-2015-PGE-Compliance_DR_ORA_005-Q23Atch01.xls)".

CHAPTER 4 UTILITY-OWNED GENERATION – FOSSIL AND OTHER GENERATION

(Witness: Michael Yeo)

I. INTRODUCTION AND RECOMMENDATIONS

This chapter addresses Pacific Gas and Electric Company's (PG&E) management and operation of its utility-owned fossil-fuel, fuel cell and photovoltaic facilities, and outages that occurred at these facilities during the 2015 Record Period.

After reviewing PG&E's testimony and responses to ORA's data requests, ORA recommends that the Commission:

(a) disallow a cost recovery of $1,284,182 in PG&E's ERRA Balancing Account for the 2015 Record Period because PG&E was responsible for the unavailability of Colusa Generating Station power for various dates in October 2015 due to the failure of the attemperator piping;

(b) order PG&E to report on the status of the corrective actions to be performed at the Colusa Generating Station as a result of the October 2015 series of power outage. The status report is to be filed in the 2017 ERRA application for the 2016 Record Period;

(c) order PG&E to evaluate Wärtsilä's quality control programs especially its corrective action plan commitments, as a result of the July 31, 2015 Humboldt Bay Generating Station outage.

II. GENERATION FACILITIES

PG&E owns, operates and maintains three fossil-fuel generating stations, two fuel cell facilities, and 10 ground-mounted photovoltaic (PV) solar stations. In addition, PG&E also owns three small PV San Francisco facilities which entered commercial operations in 2007. Because these facilities total less than 300 kW, PG&E did not address them in its direct testimony.

A. Fossil Facilities

i) Gateway Generating Station

The Gateway Generating Station (Gateway Station) is a 530 MW combined cycle power plant located in Antioch, CA. It consist of two natural gas-fired combustion turbine generators (CT) and a single steam turbine generator (ST).

Each of the two CTs has a capacity of 170MW while the ST has a capability of generating 190 MW. Additionally, Gateway Station is equipped with a capacity-enhancing technology to improve output during peak generation periods. Also, the Gateway Station uses duct burners to increase steam production in the heat recovery steam generators (HRSGs) resulting in increased ST output. The duct burners allow Gateway Station to increase its output by approximately 50 MW above the 530 MW nominal capacity.

Commission Decision (D.) 06-06-035 for PG&E's Application (A.) 05-06-029 as modified by Resolution E-4054 approved the acquisition, construction and operation of Gateway Station. It started commercial operation on January 4, 2009.

ii) Colusa Generating Station

The Colusa Generating Station (Colusa Station) is a 530 MW combined cycle power plant located near the town of Maxwell in Colusa County It consists of two natural gas-fired CT generators and a single ST generator.

Each of the two CTs has a capacity of 170MW while the ST has a capability of generating 190 MW. Additionally, Colusa Station is equipped with a capacity-enhancing technology to improve output during peak generation periods. Also, Colusa Station uses duct burners to increase steam production in the HRSGs resulting in increased ST output. The duct burners allow Colusa to increase its output by approximately 127 MW above the 530 MW nominal capacity.

The Commission, in D.06-11-048, approved PG&E's application A.06-04-012, Application of Pacific Gas and Electric Company for Approval of Long-term Request for Offer Results and for Adoption of Cost Recovery and Ratemaking Mechanisms, for the Colusa project under a purchase-and-sale agreement; the Colusa project was one of the projects in PG&E's 2004 long-term request for offers. However, even before the plant was constructed, the developer (E&L Westcoast Holdings, LLC and E&L Westcoast, LLC) exercised its rights to terminate the purchase and sale agreement. Whereupon, PG&E sought Commission approval for a Certificate of Public Convenience and Necessity (CPCN) to build the Colusa station in A.07-11-009, which the Commission approved in D.08-06-012.

Colusa Station began commercial operation on December 22, 2010.

iii) Humboldt Bay Generating Station

The Humboldt Bay Generating Station (Humboldt Station) is a 163 MW natural gas power plant located just south of Eureka, California. It consists of 10 Wärtsilä natural gas-fired reciprocating engines, each with a generating capacity of 16.3 MW.[125] Each engine has 18 cylinders, which are designated as A1 to A9 (located west of the engine) and B1 to B9 (located east of the engine). [126]

The engines are designed to run on natural gas with 1 percent of total fuel input provided by low sulfur distillate as a pilot fuel. Morever, if natural gas supply is unavailable, the plant can still operate on diesel since the engines are also designed to run on low sulfur distillate or biodiesel. Because of that contingency, Humboldt Station stores reserve diesel fuel capable of powering the facility for several days.

The current generating station replaces the former PG&E power plant system, which ran on fossil fuels and nuclear power. Before this current facility, the site, in the mid 1960's, housed the two-unit 105 MW plant and the two 15 MW Mobile Emergency Power Plants. From August 1963 to July 1976; there was also the nuclear facility, which was a 63 MW boiling-water reactor – it was shut down because the cost to comply with new safety standards was not cost effective. The nuclear plant is currently still being decommissioned.

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[125] PG&E response to ORA DR #10.5.

[126] PG&E response to ORA DR #10.10.

The Commission, in D.06-04-012 (A.06-04-012), granted PG&E's request for a CPCN for the Humboldt Bay Generating Station. It started commercial operation on September 29, 2010.

B. Fuel Cell Facilities

i) CSU East Bay Fuel Cell Facility

The California State University (CSU) East Bay Fuel Cell facility is a 1.4 MW, one fuel-cell facility located on the university campus in Hayward, California. This facility provides electricity to PG&E's electrical grid and waste heat for the university's use. The CSU facility started commercial operation on September 27, 2011.

ii) SF State Fuel Cell Facility

The San Francisco (SF) State Fuel Cell facility is a 1.6 MW facility located on the campus in San Francisco, California. There are two fuel cells at this facility:

(1) one is rated at 1.4 MW, and it provides both electricity to PG&E's electrical grid and also waste heat for the university's use;

(2) the second fuel cell is 200 kW, and provides electricity to PG&E's electrical grid. The SF State facility started commercial operation on September 27, 2011.

C. Solar Facilities

PG&E's ten PV facilities listed in chronological order of commercial operation dates shown in parenthesis are:

i. Vaca Dixon Solar Station (December 23, 2009)

Vaca Dixon, a 2 MW PV solar station located in Vacaville, California, consists of 9,672 solar modules. The station has five inverters that convert the DC energy to AC; one transformer that increases the voltage from 480 V t o 12.47 kV; and a switchgear.

ii. Westside Solar Station (September 13, 2011)

Westside, a 15 MW PV solar station located near Five Points, California, consists of over 66,000 solar modules. The station has 30 inverters; 15 transformers that increase the voltage from 440 V to 12.47 kV; and a switchgear.

iii. Stroud Solar Station (October 4, 2011)

Stroud, a 20 MW PV solar station located near Helm, California, consists of 88,000 solar modules. The station has 40 inverters; 20 transformers that increase the voltage from 440 V to 12.47 kV; and a switchgear.

iv. Five Points Solar Station (October 7, 2011)

Five Points, a 15 MW PV solar station located near Five Points, California, consists of over 75,000 solar modules. The station has 24 inverters; 12 transformers that increase the voltage from 320 V to 12.47 kV; and a switchgear.

v. Cantua Solar Station (July 25, 2012)

Cantua, a 20 MW PV solar station located near Cantua Creek, California, consists of approximately 110,000 solar modules. The station has 32 inverters; 16 transformers that increase the voltage from 320 V to 12.47 kV; and a switchgear.

vi. Giffen Solar Station (July 25, 2012)

Giffen, a 10 MW PV solar station located near Cantua Creek, California, consists of close to 55,000 solar modules. The station has 16 inverters; 8 transformers that increase the voltage from 320 V to 12.47 kV; and a switchgear.

vii. Huron Solar Station (August 30, 2012)

Huron, a 20 MW PV solar station located near Huron, California, consists of over 90,000 solar modules. The station has 40 inverters; 10 transformers that increase the voltage from 420 V to 12.47 kV; and a switchgear.

viii. Gates Solar Station (June 24, 2013)

Gates, a 20 MW PV solar station located adjacent to the Huron Solar Station near Huron, California, consists of 91,490 solar modules. The station has 28 inverters; 31 transformers that increase the voltage from 420 V to 12.47 kV; and a switchgear.

ix. West Gates Solar Station (June 24, 2013)

West Gates, a 10 MW PV solar station located near Huron, California, consists of over 45,752 solar modules. The station has 14 inverters; 14 transformers that increase the voltage from 420 V to 12.47 kV; and a switchgear.

x. **Guernsey Solar Station** (September 18, 2013)

Guernsey, a 20 MW PV solar station located near Hanford, California, consists of 89,400 solar modules. The station has 20 inverters; 27 transformers that increase the voltage from 420 V to 12.47 kV; and a switchgear.

III. Outages

Fuel Cell Facilities

In its testimony, PG&E did not report any forced outage.

Solar Facilities

In its testimony, PG&E did not report any forced outage.

Fossil Facilities

For this year's review, ORA conducted an in depth review and analyses of one outage at Colusa Generating Station (Colusa) and one outage at Humboldt Bay Generating Station (Humboldt).

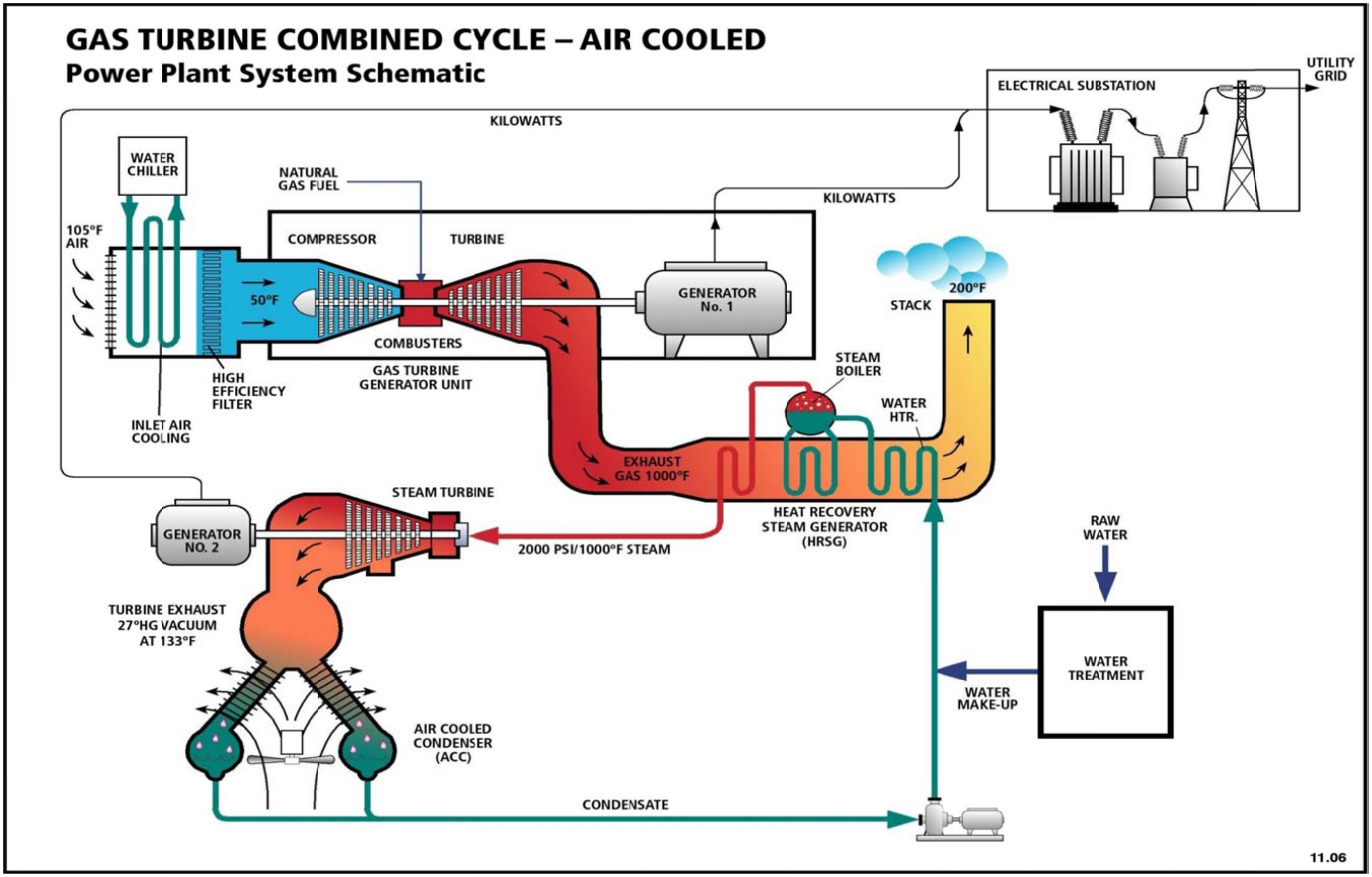
i) Colusa Generating Station Outage – October 8, 2015

(PG&E's Direct Testimony – from line 24 of page 3-19 to line 7 of page 2-21)

Figure 4-1[127] is a depiction of a gas turbine combined cycle power plant similar to the Colusa Station. Although the diagram only shows one CT and one HRSG, Colusa Station has two CTs (CT-1 and CT-2) and two HRSGs (HRSG-1 and HRSG-2); the steam from the two HRSGs is fed to the single ST. "GENERATOR No. 1", as shown in Figure 4-1, refers to the CT generator, and "GENERATOR No. 2" refers to the ST generator.

[127] PG&E response to ORA DR #6.3.

Figure 4-1 Diagram of a Gas Turbine Combined Cycle Generator



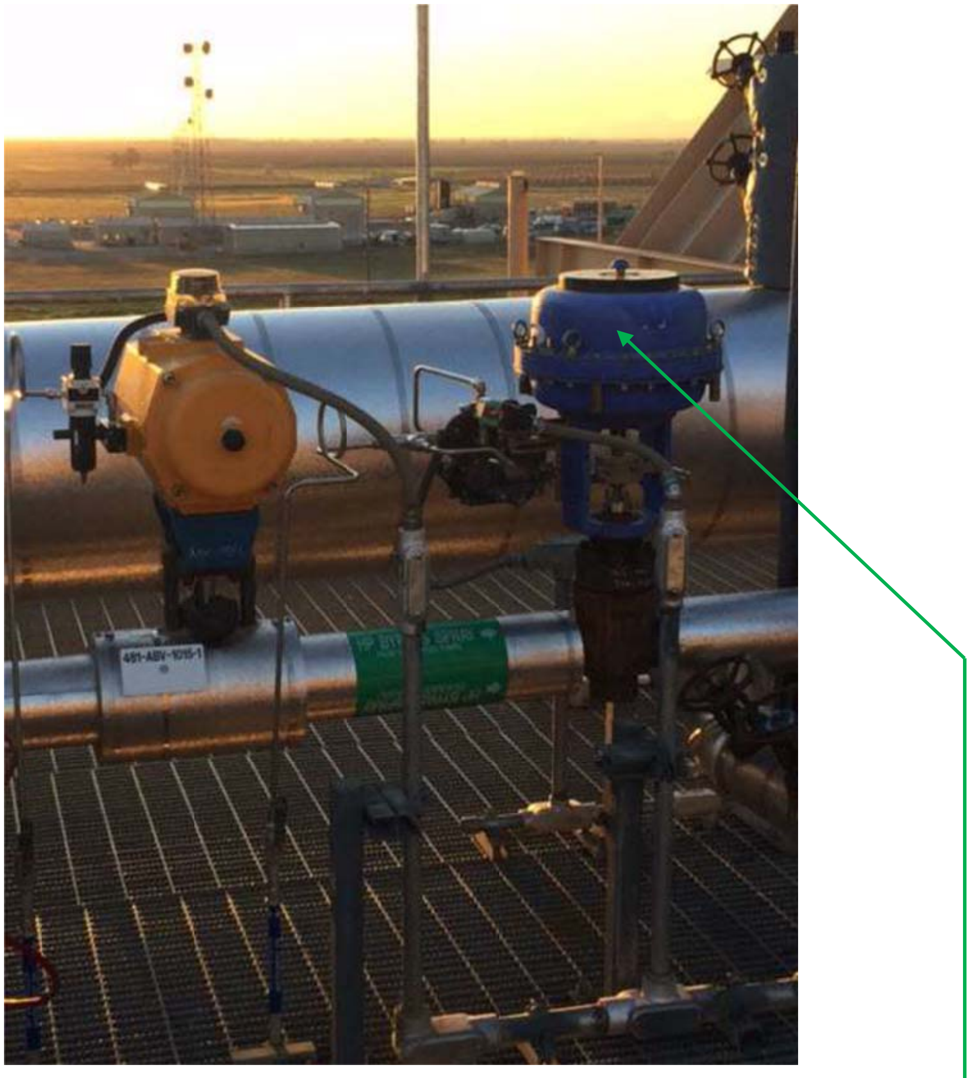
Not shown in Figure 4-1 are the following equipment used in the operation of the facility:

A. Attemperator: a device that regulates the temperature of the high pressure (HP) steam line by passing cold (or hot) water through a coil of piping.

B. Attemperation valve: a valve that controls the amount of water used to regulate the temperature of the HP steam line. During attemperation, water is mixed with the high temperature steam in order to lower the steam temperature. In the context of this incident, the attemperation valve – also known as Temperature Control Valve (TCV) 1015-1 – is used to control the amount of high pressure feedwater that is used to reduce the temperature of the high pressure steam that is being provided to the cold reheat section of HRSG 1 during start-ups.[128] The temperature set-point of an attemperation valve is the desired steam temperature downstream of the attemperator. This downstream temperature is controlled by adjusting the high pressure feedwater flow by opening and closing the attemperation valve.

[128] The reheat section of the HRSG takes the high pressure section of the steam turbine exhaust steam (referred to as cold reheat) and reheats it for admission to the intermediate pressure section of the steam turbine (referred to as hot reheat). During start-up, there is no steam flow through the steam turbine so high pressure steam is provided to the reheat section of the HRSG to keep the hot CT gases from overheating it.

Figure 4-2
Colusa Attemperation Valve- TCV 1015[129]



Attemperation valve

C. Control Logic: a feature in PG&E’s control system that allows the attemperation valve to control the steam temperature downstream of the attemperator. The control system uses two temperature sensing elements (referred to as TE1004-1 and TE 1004-2) to indicate the actual temperature of the steam in the control system. The control logic compares the actual temperature of the steam in the control system to the

[129] PG&E response to ORA DR #6.8.

desired steam temperature set-point and throttles open or close the attemperation valve to bring the actual temperature closer to the set-point.[130]

D. Ammonia Flow Transducer: a device to measure the flow of ammonia to the ammonia injection grid in the HRSG so that the control logic can control the HRSG emissions appropriately.[131]

E. Circuit Breaker: In the context of this incident, the circuit breaker for the ammonia flow transducer provides 120 volt power to the ammonia flow transmitter.[132]

According to PG&E's direct testimony, the forced outage began October 8, 2015 at 5:36 p.m. when PG&E removed Colusa from service due to the failure of a weld joint on the HRSG 1piping. The pipe connection that failed delivers attemperation water to the HP steam line that feeds the cold reheat line.[133] The forced outage ended on October 11, 2015 at 2:19 P.M.

In its response to ORA DR # 6-15, PG&E stated why it was necessary to shut down the entire Colusa Station, including the CTs, even though the failure was on the HRSG:

> *"A weld failure at the location in question would not normally cause a forced outage of the entire plant. It would normally cause a forced curtailment (ST outage). The event eventually led to a forced outage as a result of high silica levels in the boiler water system. As a result of the high silica content in the boiler water, PG&E proactively forced Colusa out of service in order to protect the HRSGs and steam turbine from damage.*
>
> *"The high silica in the boiler water was caused by the additional flow of attemperation water into the cold reheat piping as described in the RCA* [root cause analysis]. *The additional water in the cold reheat piping drained to the external drains tank and caused water to discharge from the external drains tank on to the tank vent silencer sound*

[130] PG&E response to ORA DR #6.9.

[131] PG&E response to ORA DR #6.11.

[132] PG&E response to ORA DR #6.12.

[133] PG&E response to ORA DR #6.7.

> *insulating material. That material degraded as a result of exposure to increased moisture and broke down resulting in silica being accumulated in the external drains tank, and ultimately in the boiler water system."*

PG&E's testimony enumerated several root causes to the failure of the weld joint as follows:

i. During the Root Cause Analysis (RCA), PG&E found that there was a design error in the control logic which allowed the temperature set point of the attemperation valve to operate in a way that caused the design limits of the piping system to be exceeded;

ii. The temperature set point of the attemperation valve was not adjusted to the proper level after a power plant technician (PPT) completed testing during a planned outage. PG&E's failure to correctly adjust the temperature set point allowed the attemperation valve to open wide and resulted in too much water downstream; and

iii. The circuit breaker for the ammonia flow transducer was inadvertently opened. PG&E attributed this error to the diversion of operations personnel by simultaneous occurrences of problems.

In addition to PG&E's testimony and its responses to data request questions, ORA reviewed several post-mortem documents as provided by PG&E:

(a) PG&E Root Cause Analysis Report dated October 4th 2015 (PG&E RCA Report) – PG&E has classified this [redacted]-page RCA Report as confidential.

The RCA Report describes [redacted] In its testimony, PG&E grouped [redacted]

(b) ATS Report #413.63-15.82 dated 12/8/15 entitled *Weld Repair for Colusa Unit 1 Drag Valve Ring Header Repair*– this is a 60-page report (ATS Weld Report) prepared by Applied Technology Services of San Ramon, CA for PG&E on the weld repair work;

(c) High Pressure Steam HRSG1 Bypass Outlet Pub PAUT Inspection Report dated October 9, 2015 – this is a 7-page report prepared by Team Industrial Services of Rancho Dominguez, CA, for PG&E on the inspection of 5 welds and 2 liner areas to ensure of their integrity.

(d) Three separate event reports, each of which is two pages in length – however, it is not clear from the copies provided to ORA whether the reports were prepared by PG&E because the documents do not bear any such identification:

i. a *View Event Details* document dated October 4, 2015 at 22:47:00 (Event ID #851) – it reports the failure of the HP Bypass attemperation piping and the subsequent loss of Unit A of 182 MW and curtailment of Unit C of 95 MW for 2 Days 4 hours and 13 minutes;

ii. a *View Event Details* document dated October 7, 2015 (Event #956) at 13:01:00 – it reports the deration of Unit C due to unavailability of Unit A from HP bypass attemperation piping failure; and

iii. an *Event Report Details* document dated October 8, 2015 at 16:45:00 (Event #866) – it reports that Unit A, Unit B, and Unit C were forced out due to high silica in boiler water.

From the above three event reports, there appears to be a discrepancy between the information presented in PG&E testimony and the above documents as to when the incident first started. PG&E's direct testimony states that the incident started on October 8, 2015 at 5:36 p.m. while the first document listed above (item (d).i.) states it started on October 4, 2015 at 10:47 P.M.

ORA sought for explanations on the above observations in DR #17.

<u>PG&E's responses to ORA DR #17</u>

The following text and information was provided by PG&E in its responses to ORA DR #17 to explain the observations raised in the preceding paragraphs:

a. Nomenclature:

Unit A refers to combustion turbine 1 or CT1

Unit B refers to combustion turbine 2 or CT2

Unit C refers to steam turbine generator or ST

U1, U2, U3[134] are the NERC-GADS[135] event type codes identifying a forced outage.

b. Chronology of events:

Table 4.1
Colusa Generating Station OutageS & curtailments
Chronology of Events

Line No.	NERC Event Type	Start	End	MW Loss	Description
1	D1[136]	10/04/2015 22:47	10/07/2015 02:00	265	HP bypass attemperation piping failed (CT1 & ½ ST)
2	RS	10/04/2015 22:47	10/04/2015 23:31		Reserve Shutdown for CT2 & ½ ST
3	RS	10/06/2015 00:53	10/06/2015 04:26		Reserve Shutdown for CT2 & ½ ST
4	RS	10/07/2015 00:04	10/07/2015 02:00		Reserve Shutdown for CT2 & ½ ST
5	U1	10/07/2015 02:00	10/07/2015 13:01	530	HP bypass attemperation piping failed and replace aux safety (block forced outage)
6	D1	10/07/2015 13:01	10/08/2015 16:45	265	HP bypass attemperation piping failed (CT1 & ½ ST)
7	RS	10/07/2015 13:01	10/07/2015 13:32		Reserve Shutdown for CT2 & ½ ST
8	D1	10/08/2015 16:45	10/08/2015 17:36	360	HP bypass attemperation piping failed and high silica in the boiler water (CT1 & ST)
9	U1	10/8/2015 17:36	10/11/2015 14:19	530	HP bypass attemperation piping failed (block forced outage)

The above table includes the chronology of events as to the different outages and curtailments (including the events described in the above three documents) starting from October 4, 2015 at 22:47:00 and leading to October 11, 2015 at 2:19 p.m. Event type D1 represents a forced curtailment; U1 represents a forced outage; and RS represents a reserve shutdown. Note that a combined cycle block forced outage requires CT1, CT2, and STG to be forced out of service.

i. For the *View Event Details* document dated October 4, 2015 at 22:47:00 (Event ID #851):

The HP Bypass attemperator piping failed. CT1 was shut down due to the HP bypass attemperator piping failure. When one CT is in a forced outage this automatically places a derating on the STG

[134] U1 is an Unplanned (Forced) Outage — immediate; U2 is an Unplanned (Forced) Outage — Delayed; U3 is an Unplanned (Forced) Outage — Postponed) http://www.nerc.com/files/Section_3_Event_Reporting.pdf.

[135] North American Electric Reliability Corporation Generating Availability Data System

[136] A D1 event is an unplanned (forced) derating. http://www.nerc.com/files/Section_3_Event_Reporting.pdf

and reduces the combined cycle block from 2x1 configuration to 1x1 configuration. This is equivalent to a 50 percent block curtailment (265 MW).

ii. For the *View Event Details* document dated October 7, 2015) at 13:01:00 (Event #956):

There was a short block forced outage of approximately 11 hours to replace an auxiliary safety value ending at 10/07/2015 at 13:01:00. At the conclusion of this work CT2 was made available and placed on reserve shutdown. CT1 was already unavailable due to the HP bypass attemperator piping failure and the combined cycle block was available for 1x1 configuration (curtailment of 265 MW).

iii. For the *Event Report Details* document dated October 8, 2015 at 16:45:00 (Event #866):

The steam turbine generator (STG) was forced out due to high silica in the boiler water. CT1 was already unavailable due to the HP bypass attemperator piping failure. This rendered CT1 and STG unavailable during this time. CT2 was available for operation. This resulted in a forced curtailment of 360 MW.

iv. For those events that happened prior to outage October 8, 2015 at 5:36 p.m.:

PG&E typically, in its testimony regarding outages in ERRA compliance proceedings, only provides specific information regarding each forced outage (such as an event coded as U1, U2, or U3) that was longer than 24 hours in duration, and for facilities that are 25 MW or greater in size. As such, based on the information of the various incidents shown in Table 4.1, the Colusa forced outage that began October 8, 2015 at 5:36 p.m. and ended October 11, 2015 at 2:19 p.m. is the only outage that meets the above criteria for inclusion in PG&E's direct testimony.

Corrective Actions

In addition to the weld repair, PG&E also identified the following corrective actions:

a. reprogram system logic to include limits for minimum and maximum attemperation set points for all attemperation and similar valves. The valve's set points establish the appropriate upper and lower bounds to the normal steam temperature set point.

b. determine if the same condition exists with other systems at Colusa or other generation facilities.

[redacted] develop a human performance tool for documenting temporary changes to settings for testing on all plant equipment to ensure all changes are reverted to original setpoints. (The RCA Report discloses [redacted]

d. evaluate the labeling for the circuit breaker panel for the ammonia flow transducer and similar panels.

e. evaluate locking devices for 120 volt AC breakers.

PG&E's testimony on the above corrective actions [redacted] in the RCA Report. It is not clear from the documents reviewed whether all the corrective actions have been completed, or when they are scheduled for completion.

Cost of Outage

In its response to ORA DR #6.28, PG&E stated that the outage (from October 8, 2015 at 5:36 p.m. and ended on October 11, 2015 at 2:19 p.m.) cost ratepayers $476,581 in replacement power; this amount is the difference between the actual replacement energy cost and the various CAISO charges (such as, congestion cost, real-time Uninstructed Imbalance Energy cost and other CAISO costs). However, ORA maintains that because the attemperator piping failure incident started on October 4, 2015, the entire episode, including those various power unavailability events listed in Table 4.1, had a total power replacement cost of $1,284,182.[137]

In addition, the direct PG&E cost of repairing the damage was $144,106.[138] The cost breakdown of this amount is as follows:

[137] PG&E's response to ORA DR #17.6

[138] PG&E's response to ORA DR #6.33

Table 4-2
Direct PG&E Cost of Colusa Outage

Line No.	Description	Amount
1	PG&E Labor	$69,335
2	Contract	65,995
3	Materials	8,582
4	Other	195
5	Total	$144,106

Therefore, the total cost of this outage including replacement power and PG&E's Direct cost is approximately $1,428,288. PG&E adds that the above Direct PG&E cost of $144,106 is addressed through PG&E's General Rate Case (see Attachment 4.1).

ii) Humboldt Bay Generating Station Outage – July 31, 2015

According to PG&E's testimony, Unit 8 of Humboldt Station underwent a forced outage, which began July 31, 2015 at 9:00 a.m. and ended on August 5, 2015 at 8:54 a.m. The outage was due to the failure of the A9 cylinder head exhaust valve seat/jacket, the purpose of which is to prevent water and oil from leaking into the cylinder and exhaust header. An oil-mist detector, a protective device that detects burnt oil mist, sent a signal to the Wärtsilä Engine Control System (WECS) Programmable Logic Controller (PLC) to shut down the engine in order to protect the engine from any further damage,.[139]. The oil-mist detector also set off an alarm to the operators to alert them of the problem.

PG&E's testimony explains that because Wärtsilä rebuilt the A9 cylinder during the April/May 18,000-hour major overhaul, PG&E filed a warranty claim with Wärtsilä for the cause of the valve/jacket failure. In its response to ORA DR # 10.28, PG&E adds, "*The failure was due to poor quality control at the Wärtsilä shop in Seattle. Wärtsilä failed to insert o-rings and a seal during the 18,000 hour major overhaul.*"

In addition to PG&E's testimony and its responses to data request questions, ORA reviewed the following documents:

[139] PG&E's response to ORA DR #10.19.

(a) *View Event Details* document dated July 31, 2015 at 09:00:00 (Event ID #817) – this one-page document reports that Unit 8 of the Humboldt Station was tripped by the oil mist detector and the subsequent reconditioning of the cylinder head at the shop of the engine manufacturer.

It is not clear from the copy provided to ORA whether the report was prepared by PG&E because the documents do not bear any such identification.

(b) Wärtsilä's Work Report entitled *Humboldt Bay Repowering Project 18V50 Leaking Cylinder Head* (Wärtsilä Report) – this 10-page document dated 9/13/2015 describes the Unit 8 A9 cylinder head repair which was completed on September 11, 2015.

(c) Email correspondence between PG&E's Charles Holm and Wärtsilä's Juan Ruiz, agreeing to cover all the repairs for the cylinder head.[140] The email correspondence covers the dates from August 10, 2015 11:20 at a.m. to August 14, 2015 at 7:51 a.m. The email also states that PG&E would ship the cylinder head to Wärtsilä shortly after August 10, 2015.

There appears to be a discrepancy between the information presented in PG&E testimony on the Humboldt outage and that shown in the above documents (b) and (c) with regards to the period of the incident. The testimony states that the unit was returned to reserve shutdown on August 5, 2015 at 8:54 a.m. while the above document (b) and (c) indicates that the repair was not even started till way past August 5, 2015. PG&E, in its response to ORA DR #19-01, provided the following clarification:

> '*The Unit 8 cylinder head that required repair was replaced with a spare cylinder head so the forced outage could end and the unit could be made available for dispatch on August 5, 2015. The cylinder head that was removed from the engine was repaired by Wärtsilä and returned after September 11, 2015 to PG&E to be used as a spare.*"

The below table and explanation show the chronology of events pertaining to the Humboldt outage (as provided by PG&E in its response to ORA DR #19-01d, #19-01e

[140] PG&E's response to ORA DR #10.31, Attachment 1.

and #19-2.):

Table 4-3
Humboldt Bay Generating Station Outage
Chronology Of Events

Line No.	NERC Event Type	Start	End	MW Loss	Description
1	U1	7/31/2015 09:00	8/05/2015 08:54	16.3	
2	N/A	8/05/2015 08:54	8/05/2015 09:16	0	Unit Placed into Operation for Test Run
3	RS	8/05/2015 09:16	8/9/2015 20:40	0	Reserve Shutdown (Available for Dispatch)

The unit was made available for service on August 5, 2015 at 8:54 A.M. However, the unit was not needed by the CAISO at the conclusion of the forced outage. Therefore, after a short test run, the unit was placed on reserve shutdown. A “reserve shutdown” means that a unit is available to generate power for load, but is not due to lack of demand.

As to why a Root Cause Analysis Report was not prepared PG&E, in its response to ORA DR # 10.23, explained, “*Root Cause Analyses are typically performed when the cause of the forced outage is not clearly understood. A Root Cause Analysis requires a significant investment of time and resources. In this case, the cause of the forced outage was very clear so PG&E did not consider doing a formal root cause analysis.*”

Corrective Actions

Repairs were made to the A9 cylinder head exhaust valve seat/jacket and the unit was returned to reserve shutdown[141] August 5, 2015 at 8:54 a.m.

In addition to the repairs done during the outages as stated above and in PG&E testimony, Wärtsilä also provided PG&E with actions they have taken to prevent a recurrence (see Attachment 4.2). These actions include:

a. Reevaluation of workers’ competencies;
b. Spot quality check;
c. Instituting an internal audit system; and
d. A parts-counting methodology to account for missing parts during equipment work.

[141] In PG&E’s response to ORA DR #10.22, PG&E explains that “reserve shutdown” means an event where a unit is available for load but is not synchronized due to lack of demand.

Cost of Outage

In PG&E's response to ORA DR #10.29, it stated that the replacement power cost for the July 31, 2015 outage was negative $29.52. PG&E explained this cost was negative (a credit) because this amount "*...broadly reflects Day-Ahead Market (DAM) settlement credits being somewhat larger than the sum of the Real-Time Market (RTM) imbalance energy and Replacement costs during the relevant determination periods.*"

In addition, the direct PG&E cost of restoring the ST generator stator end winding damage was $45,493[142]. The cost breakdown of this amount is as follows:

Table 4-4

Direct PG&E Cost of Humboldt Outage

Line No.	Description	Amount
1	PG&E Labor	$ 8,749
2	Contract	0
3	Materials	36,744
4	Other	0
5	Total	$ 45,493

The above costs are for disassembly, reassembly, and lubricating oil. PG&E adds that the above direct PG&E cost of $45,493 is addressed through PG&E's General Rate Case. Wärtsilä, however, did cover the cost of repairing the cylinder head.

While this Humboldt outage in July 31, 2015 did not affect ratepayers in replacement power cost, ORA is concerned about future outages that could impact ratepayers. Therefore, ORA recommends that PG&E evaluate Wärtsilä's quality control program, especially its corrective action plan commitments as identified in Attachment 4.2.

IV. CONCLUSIONS AND RECOMMENDATIONS

Based on ORA's review of the other afore-mentioned documents and reports, ORA determines that PG&E was responsible for the October 2015 Colusa outage events

[142] PG&E's response to ORA DR #10.34.

because PG&E admitted that the cause of the power generation disruptions was due to design error and mistakes made by plant personnel. In the case of Humboldt Bay Generating Station, ORA is concerned with Wärtsilä's work performance which caused the July 31, 2015 outage.

In conclusion, ORA recommends that the Commission:

(a) disallow cost recovery of $1,284,182 in PG&E's ERRA Balancing Account for the 2015 Record Period because PG&E was responsible for the unavailability of Colusa Generating Station power y for various dates in October 2015 due to the failure of the attemperator piping.

(b) order PG&E to report on the status of the corrective actions to be performed at the Colusa Generating Station as a result of the October 2015 power disruption events. The status report is to be filed in the 2017 ERRA application for the 2016 Record Period; and

(c) order PG&E to evaluate Wärtsilä's quality control programs especially its corrective action plan commitments, as identified in Attachment 4.2, as a result of the July 31, 2015 Humboldt Bay Generating Station outage.

LIST OF ATTACHMENTS FOR CHAPTER 4

ATTACHMENT 4.1
PG&E's Direct Cost – COLUSA Outage
PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_006-Q33		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_006-Q33		
Request Date:	March 17, 2016	Requester DR No.:	006
Date Sent:	March 31, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Alvin Thoma	Requester:	Michael Yeo

COLUSA GENERATING STATION (CHAPTER 3)

QUESTION 33

How much did it cost PG&E to replace the damaged parts? Please provide the cost breakdown (labor, materials, etc.) and workpapers. If there are numerous cost items less than $100,000, please group them in the appropriate categories.

ANSWER 33

PG&E objects to this request to the extent that it seeks information that is beyond the scope of issues in this proceeding. Operation and maintenance and capital costs are addressed through PG&E's General Rate Case.

Subject to this objection, PG&E states as follows: The cost to complete the inspection and repair of the HP bypass to CRH Valve & Piping was approximately $144,106. The breakdown of the $144,106 is as follows:

TABLE 1
COST BREAKDOWN

Line No.	Description	Amount
1	PG&E Labor	$ 69,335
2	Contract	65,995
3	Materials	8,582
4	Other	195
5	Total	$ 144,106

Supporting workpapers are included as Attachment 1 to this data response (see Excel document, "ERRA-2015-PGE-Compliance_DR_ORA_006-Q33Atch01.xlsx").

ATTACHMENT 4.2

Corrective Actions by Wärtsilä (Engine Manufacturer)

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_010-Q41Supp01		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_010-Q41Supp01		
Request Date:	March 30, 2016	Requester DR No.:	010
Date Sent:	May 13, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Alvin Thoma	Requester:	Michael Yeo

HUMBOLDT BAY GENERATING STATION (CHAPTER 3)

QUESTION 41

Please provide all corrective actions done or to be done to prevent the recurrence of similar incidents, including scheduled inspections and maintenance.

ANSWER 41 – SUPPLEMENTAL

PG&E recently received additional information from Wärtsilä regarding corrective actions they are taking to prevent a recurrence. Wärtsilä stated the following in a recent correspondence with PG&E:

- We have realigned our worker competencies within the organization to help ensure the best worker is assigned to each task. During this process we have also done revaluations of each workers' strengths and weaknesses, and have provided additional trainings where "refreshers" were needed.
- We have outlined in our workshop processes a new series of quality spot checks that are performed throughout the overhauling process. This includes inspection of tools, ensuring most up to date manuals and bulletins are used, double checking measurements taken, placement of o-rings, etc.
- Going off of the previous line mentioned, we have created an internal audit system to ensure the proper procedures are being followed according to Wärtsilä standards. One brief example of this in depth procedure, for cylinder heads in particular, is as follows:
    - Once the heads are marked complete for final inspection and assembly, at least one head is randomly checked, before it is assembled. It is sent to be pressure tested again by our designated quality person. All items are measured again, and measurements are checked with what was recorded previously to ensure no inconsistencies. Placement and presence of o-rings are inspected.
- More specifically focused on o-rings and seals, a parts counting method has been developed to ensure no parts are missing during reconditioning and overhaul. One example; If a specific number of heads are received, the o-rings and seals that are to be replaced are sorted out in advanced and counted by

ATTACHMENT 4.2 (continued)

Corrective Actions by Wärtsilä (Engine Manufacturer)

two or more persons. Completion of the overhaul with remaining parts will be an indicator to us that not all seals have been installed. Since implementation of this process, we have not had any occurrences of missing parts.

CHAPTER 5 COSTS INCURRED AND RECORDED IN THE DIABLO CANYON SEISMIC STUDIES BALANCING ACCOUNT

(Witness: Brian Lui)

I. INTRODUCTION AND RECOMMENDATION

This testimony addresses Chapter 5 of PG&E's 2015 ERRA compliance application, which covers the Diablo Canyon Seismic Studies Balancing Account (DCSSBA) for the Record Period of January 1, 2015 through December 31, 2015. ORA performed an audit of PG&E's DCSSBA to determine whether entries recorded in the account were appropriate, correctly stated, and in compliance with the applicable Commission decisions.

After reviewing PG&E's application, testimony and responses to ORA's data requests, ORA found that the entries in the Diablo Canyon Seismic Studies Balancing Account are appropriate, correctly stated, and in compliance with Commission decisions. ORA found no exceptions to the recovery requirements.

II. BACKGROUND

The purpose of the DCSSBA is to record and track actual costs associated with conducting additional seismic studies and other related activities to implement the California Energy Commission Assembly Bill (AB) 1632 Report recommendations. D.12-09-008 authorized PG&E to record and recover in rates costs associated with implementing the Diablo Canyon Power Plant (DCPP) seismic activities in its DCSSBA, up to an established cap of $64.25 million. In D.12-09-008, the Commission stated that PG&E could recover the costs incurred and recorded in the DCSSBA its annual ERRA proceeding so long as the costs were consistent with PG&E's Application (A.) 10-01-014 and related Tier 3 advice letters.

In D.14-08-032, the Commission directed PG&E to remove $4.84 million in Long Term Seismic Program (LTSP) costs from the 2014 revenue requirement for purposes of the 2014-2016 General Rate Case and to transfer the LTSP costs to the DCSSBA.

III. ORA REVIEW OBJECTIVES, SCOPE, AND PROCEDURES

ORA reviewed PG&E's DCSSBA for entries made in 2015 that totaled $6.70 million. The objective of ORA's review was to determine whether the entries recorded in the account were appropriate, correctly stated, and in compliance with applicable

Commission decisions. ORA's audit procedures included, but were not limited to the following:

- Review of PG&E's application, testimony, exhibits, workpapers and Master Data Request responses.
- Preparation and issuance of Data Requests and review of PG&E's responses.
- Review of applicable Advice Letters and Commission Decisions.
- Selection of a sample of DCSSBA monthly line items to determine whether adequate support exists.
- Examination of invoices, general ledger entries, and related accounting records for amounts recorded in the DCSSBA.
- Verification of mathematical accuracy of accounting worksheets and supporting documentation.
- Onsite audit to review and discuss each of the ORA selected DCSSBA monthly line items in detail with PG&E staff and to trace those line items to PG&E's general ledger.
- Review to determine whether PG&E's recorded costs were appropriate and correctly stated.
- Review to determine whether PG&E complied with applicable Decisions and Advice Letters.

On a sample test basis, ORA reviewed source documents that support costs recorded in the DCSSBA. A "judgment sample" is a type of nonrandom sample selected by the auditor based on the judgment (opinion) of the auditor. When an auditor selects a judgment sample, he/ she makes judgments about various elements including the internal control environment, exposure/materiality, and risk. ORA's "judgment sample," consisted of 22 recorded monthly line items.

Table 5-1 below presents costs recorded by PG&E in the DCSSBA for the 2015 record period, by category:

Table 5-1 Diablo Canyon Seismic Studies Balancing Account

Line No	Category	Recorded Costs incurred in 2015 ($ Million)
1	**AB 1632 Seismic Studies**	
2	Seismic Survey Design	$0.00
3	Offshore 2D/3D LESS[143]	$0.06
4	Offshore 3D HESS[144]	$0.05
5	Onshore 2D/3D	$0.65
6	Ocean Bottom Seismometer Installation	$0.39
7	Project Management	$0.71
8	Subtotal	**$1.86**
9	**Long-Term Seismic Studies**	
10	SSHAC[145]	$0.99
11	Seismic Source Studies	$0.40
12	Ground Motion Studies	$2.81
13	Project Management	$0.64
14	Subtotal	**$4.84**
15	Total	**$6.70**

IV. CONCLUSION

ORA found that the entries in the Diablo Canyon Seismic Studies Balancing Account are appropriate, correctly stated, and in compliance with Commission decisions. ORA found no exceptions to the recovery requirements.

[143] Low Energy Seismic Surveys.

[144] High-Energy Seismic Surveys.

[145] Senior Seismic Hazard Analysis Committee.

CHAPTER 6 GENERATION FUEL COSTS AND ELECTRIC PORTFOLIO HEDGING

(Witness: Monica Weaver)

I. INTRODUCTION AND SUMMARY

ORA reviewed PG&E's 2015 Energy Resource Recovery Account (ERRA) testimony regarding Generation Fuel Costs and Electric Portfolio Hedging for the Record Period January 1, 2015 through December 31, 2015[146] to evaluate whether PG&E prudently: procured fuel for its retained generation facilities and tolling agreements, managed fuel supply requirements for the California Department of Water Resources (CDWR) tolling agreements, acquired water for hydroelectric generation, and procured nuclear fuel for Diablo Canyon Power Plant (DCPP). In addition, ORA reviewed PG&E's electric portfolio hedging and evaluated PG&E's implementation of its 2010 and 2014 Bundled Procurement Plans.

II. RECOMMENDATION

ORA does not take exception to PG&E's implementation of the 2010 and 2014 hedging plans during the Record Period. Likewise, ORA does not take any exceptions to PG&E's procurement of fuel for its retained generation facilities and tolling agreements, management of fuel supply requirements for the CDWR tolling agreements, acquisition of water for hydroelectric generation, and procurement of nuclear fuel for DCPP.

ORA recommends that PG&E submit the independent auditor's review of STARS Alliance to ORA and the Commission, once completed or that PG&E should include the audit in the 2016 Record Period ERRA- Compliance Filing.

III. ORA REVIEW OBJECTIVES, SCOPE, AND PROCEDURES

ORA reviewed PG&E's application, testimony, workpapers, and PG&E's responses to ORA's data requests. ORA audited for fuel procurement costs documented in the ERRA balancing account.

ORA also audited transactions within the STARS Alliance and in the 2010 and 2014 Bundled Procurement Plans. In conducting this audit, ORA discovered several discrepancies in PG&E's direct testimony through discovery and data requests. After ORA

[146] A.15-02-019 PG&E's Testimony Chapter 6.

discovered discrepancies, PG&E prepared amended testimony, which was served on April 20, 2016. ORA reviewed both the original testimony and the amended testimony. Included in PG&E's errata was a new STARS Alliance annual report. PG&E's amended testimony and data request responses clarified and eliminated the discrepancies. Additionally, in its response to ORA's data request sent on March 18, 2016, PG&E stated that "an external independent audit firm will audit STARS 2015 financial statements in the later part of 2016."[147]

Following ORA's review of PG&E's Chapter 6, Table 6-1 below was created to present Generation Fuel Costs for Record Period 2015.

Table 6-1 Generation Fuel Cost Record Period 2015

PG&E Chapter 6- Generation Fuel Cost	RP 2015 $ Total
1. Gas Procurement Natural gas burned at PG&E-owned generation facilities	[redacted][148]
2. Gas Procurement Gas Expenses for bilateral tolling agreements and contracts	[redacted][149]
3. Distillate Expenses Distillate and heavy fuel oil burned at PG&E fossil plants	$596,654[150]
4. Water Purchased for Power Hydroelectric fuel expenses	$1,967,178[151]
5. Nuclear Fuel Expenses Fuel expenses for DCPP	[redacted][152]
6. Nuclear Fuel-Related Products or Services [redacted]	[redacted][153]
7. Nuclear Fuel Inventory Carrying Costs Carrying Cost	[redacted][154]
Total	[redacted]

[147] PG&E response to ORA's Data Request #007, Question #08. See Attachment.

[148] PG&E Testimony, Table 6B-1 workpapers, PG&E asserts that the figures in ORA Table 6-1 are confidential.

[149] PG&E Testimony, Table 6B-1 and 6B-1 workpapers

[150] PG&E Testimony, page 6-9, line 28, Table 12-2, tariff line 5k.

[151] PG&E Testimony, page 6-10, line 1.

[152] PG&E Testimony, Table 12-2, tariff line 5m.

[153] PG&E Testimony, Table 6B-6, line 13.

[154] PG&E Testimony, page 6-12 line 6, Table 12-2, tariff line 5y.

IV. CONCLUSION

ORA does not take exception to PG&E's: procurement of fuel for its retained generation facilities and tolling agreements, management of fuel supply requirements for the CDWR tolling agreements, acquisition of water for hydroelectric generation, or, procurement of nuclear fuel for DCPP. ORA concludes that PG&E's generation fuel costs comply with PG&E's approved Bundled Procurement Plans for the Record Period. ORA determined that the 2010 and 2014 Bundled Procurement Plans were reasonably administered and all transactions complied with the standards in the hedging plans. Based on PG&E's assertion that an independent firm will perform an external audit of STARS Alliance, ORA recommends that PG&E submit the external audit to ORA and the Commission once completed or PG&E should include the audit in the 2016 ERRA Record Period.

ATTACHMENT 6-1: PG&E's Response to ORA's Data Request 007, Question 08 (emphasis added).

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request No.:	ORA_007-Q08		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_007-Q08		
Request Date:	March 18, 2016	Requester DR No.:	007
Date Sent:	April 1, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Susan Hunter	Requester:	Monica Weaver

QUESTION 8

Regarding Data Request #2 question 8 d. Section G the amount of $502,746. Provide a further breakdown of Attachment C. Including items such as screen shots, general ledgers or subledgers. The subcategories for further breakdown include: Labor, Benefits & Bonus, Travel Expenses, Building Lease/ Utilities.

ANSWER 8

Subsequent to PG&E's filing of the 2015 ERRA Compliance Review Application, STARS Alliance, LLC completed an internal assessment of the accounting records and discovered several errors that needed to be corrected. In response to this data request, PG&E provides a summary of the issue and remediation efforts underway to prevent similar errors in the future. Also, attached is the revised Appendix C appearing in Chapter 6 of PG&E's Prepared Testimony and a schedule that provides further breakdown of the cost categories as requested. The revised amount to be reported in Section G is $529,682. PG&E intends to file amended Prepared Testimony in April 2016 to correct these inadvertent errors in Chapter 6, as well as any other necessary corrections.

In 2014 and 2015, STARS Alliance, LLC (STARS) experienced personnel turnover and lost some key institutional accounting knowledge. In addition, STARS had been using SAGE accounting software which was poorly configured and non-intuitive. In 2015, STARS hired a new Business Operations Manager who began to take remediation action to correct potential deficiencies in the accounting systems and processes. Two key aspects of the improvements were to hire a third party consultant with the proper accounting expertise to maintain the financial records and to adopt QuickBooks as the new accounting software. The external consultant completed the transition to QuickBooks in 2016 and during the process of converting data from SAGE to QuickBooks, discovered several errors in the accounting records (during the periods 2012 through 2015). The errors were all corrected in 2015 and the updated Appendix C shows the corrected amounts. **In addition, an external independent audit firm will audit STARS' 2015 financial statements in the later part of 2016.**

CHAPTER 7 GREENHOUSE GAS COMPLIANCE INSTRUMENT PROCUREMENT AND COSTS

(**Witness**: Ayat Osman, Ph.D.)

I. INTRODUCTION

On February 29, 2016, Pacific Gas and Electric Company (PG&E) filed an application requesting the Commission to approve its "Compliance Review of Utility Owned Generation Operations, Electric Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Owned Generation Fuel Procurement for the Period of January 1 through December 31, 2015" (Application).

On June 1, 2016 the Commission held a prehearing conference to discuss the scope of the proceeding, develop a procedural timetable for management of the proceeding, and establish the service list. On June 16, 2016, the Scoping Memo and Ruling of Assigned Commissioner on the Application (Scoping Memo) was filed and served.

The objective of the review presented in this testimony is to address PG&E's compliance with Commission and State rules and regulations regarding the procurement of greenhouse gas (GHG) compliance instruments and associated costs, the accuracy and reasonableness of these costs, and determine whether PG&E has operated and managed its GHG program in a least-cost manner. Specifically, this testimony addresses the following issues that are identified in the Scoping Memo of this proceeding, as they relate to PG&E's GHG compliance:[155]

- Whether PG&E's entries in the ERRA for 2015 are reasonable;
- Whether PG&E met its burden of proof regarding its claim for cost recovery;
- Whether PG&E's Greenhouse Gas Compliance Instrument procurement complies with the 2010 and 2014 bundled procurement plans (BPP);
- Whether PG&E met its burden of proof regarding greenhouse gas costs listed in chapter 12 of the PG&E testimony;

[155] Scoping Memo, p. 3.

- Whether PG&E is seeking recovery for Indirect greenhouse gas costs from third parties providing power; and
- Whether PG&E met its burden with regards to the Indirect costs.

To conduct its review on the issues stated above, ORA:

- Reviewed PG&E's application, including testimonies and workpapers, that are relevant to GHG compliance for the 2015 Record Period;
- Reviewed PG&E's GHG chapters in its 2010 and 2014 BPP, the relevant advice letters, resolutions and Commission Decisions;
- Issued data requests and held multiple Meet and Confer meetings to obtain supporting data for PG&E's claims with regards to the procurement of GHG instruments and their associated costs;
- Conducted analysis based on PG&E's responses to ORA's data requests to determine whether PG&E applied methodologies for calculating the GHG emissions and associated costs correctly, (consistent with Commission and state regulations and laws), and recorded its GHG emissions and costs accurately; and
- Reviewed supporting data to determine whether PG&E operated and managed its GHG program in a least-cost manner.

II. SUMMARY AND RECOMMENDATIONS

In the January 1, 2015 through December 31, 2015 Record Period, PG&E claimed that it incurred greenhouse gas (GHG) compliance instrument procurement costs (Direct GHG costs) of [redacted] to comply with the California Air Resources Board (CARB or ARB) Cap-and-Trade Regulation.[156] PG&E claimed that it was exposed to Indirect GHG costs embedded in the cost of procuring energy from market purchases and contracts that do not have a specific provision for settlement of GHG costs. PG&E estimated total Indirect GHG cost as [redacted].[157] PG&E did not record Indirect GHG costs in a

[156] PG&E response to ORA data request number 09, question 6 [Confidential]. ORA Data Request Issued March 28, 2016. PG&E Response received April 8, 2016.

[157] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

separate ERRA subaccount. In this application, PG&E must provide the necessary information and relevant calculations in detail sufficient for ORA and the Commission to determine whether the GHG emissions and costs identified are reasonable and consistent with Commission and state policies and law.

Based on ORA's review of PG&E's application, supporting workpapers, and responses to ORA data requests, PG&E did not substantiate its calculation of Direct GHG emissions from the energy it procured from PG&E's owned-facilities, tolling agreements, Qualifying Facility (QF) contracts, and imports. As such, ORA could not verify whether PG&E's calculation of Direct GHG emissions was accurate, and whether the resulting Direct GHG costs, listed in Chapter 12 of PG&E's Testimony, are reasonable. ORA recommends that the Commission disallow PG&E's claim for cost recovery of Direct GHG costs totaling [redacted] (reported under ERRA Tariff Line Item 5.ah in Table 12-1 of PG&E's Testimony).[158]

ORA issued multiple data requests to verify PG&E's estimates of Indirect GHG costs.[159] PG&E did not provide the calculations that ORA requested to show how the Indirect GHG emissions were estimated.[160] With the exception of Indirect GHG costs associated with energy procured from California Independent System Operator (CAISO) market purchases, ORA could not verify PG&E's calculation of Indirect GHG emissions resulting from energy procured through contract purchases and whether their associated Indirect GHG costs were reasonable.[161]

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[158] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[159] ORA data request number 09, issued on March 28, 2016; ORA data request number 15 issued April 21, 2016; and ORA data request number 20 issued May 10, 2016.

[160] PG&E response to ORA data request number 15, question 01, (b., c., d.) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

[161] ORA noticed discrepancies in PG&E's responses to data requests, which triggered ORA to further investigate PG&E's calculations to ensure that the costs are recorded accurately. For instance, PG&E provided conflicting cost entries in responses to two of ORA's data requests: in one response, PG&E 's estimate of Indirect GHG costs associated with CAISO purchases was [redacted], whereas in another response, PG&E's estimate of Indirect GHG costs associated with the same source was about [redacted], a difference of about [redacted]. In another instance, PG&E reported Indirect GHG costs (associated with a certain category of contract purchases) as [redacted], whereas in a response to another data request, PG&E reported the costs for the same sources were about [redacted], a difference of about [redacted].

ORA recommends that the Commission approve the Indirect GHG costs associated with CAISO market purchase in the amount of [redacted], which is embedded in the cost reported under ERRA Tariff Line Item 5.t in Table 12-1 of PG&E's Testimony.[162]

ORA recommends that the Commission disallow a total of [redacted] associated with energy procured from:

- Contract Purchases- PG&E's estimated Indirect GHG costs from contract purchases were [redacted].[163] PG&E provided emissions associated with [redacted] sources, but did not indicate which contracts (contracts with no specific provision for settlement of GHG costs) cover these sources.[164] PG&E did not provide the calculations used to estimate the Indirect GHG emissions associated with energy procured from these contracts. Per D.15-01-024, the GHG emission calculations should be based on the actual plant output purchased by a utility and contract-specific terms.[165] PG&E did not provide the actual plant output purchased per contract used for the calculation of the Indirect GHG emissions, nor did it provide contract-specific terms used for those calculations. PG&E indicated that the Indirect GHG costs associated with these contract purchases were recorded under three ERRA Tariff Line Items 5.ae, 5.n, and 5.o, but did not specify which contracts were recorded under which specific Tariff line item.[166]As such, ORA was not able to verify the reasonableness of the methodologies used to calculate these emissions to determine if they are consistent with Commission and state policies and law. Therefore, ORA was not able to determine if PG&E's estimated Indirect GHG costs are reasonable, and how they correlate to the procured energy and costs reported under tariff line items 5.ae, 5.n, and 5.o.; and

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[162] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[163] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E response received May 23, 2016. See Exhibit 1.

[164] ORA notes that multiple sources could be associated with a single contract. *Id*. Spreadsheet tab titled Line 11, and Spreadsheet tab titled Line 18 [Confidential].

[165] D.15-01-024, Attachment D, Template D-2, page 9.

[166] PG&E response to ORA data request number 20, question 12. [Confidential] ORA data request issued May 10, 2016. PG&E response received May 23, 2016. See Exhibit 3.

- Contract Purchases with Financial Settlement- PG&E's estimated GHG costs from these categories of contracts was [redacted].[167] PG&E provided emissions associated with [redacted] sources (related to contracts with specific financial settlement provisions for GHG costs), but did not identify the calculations used to generate the GHG emissions, nor the relevant contract terms that were used to calculate the associated costs.[168] PG&E indicated that GHG costs associated with these contract purchases were embedded in the costs that were recorded under three ERRA Tariff line Items 5.ae, 5.n, and 5.o, but did not specify which contracts were recorded under which specific Tariff line item.[169] As such, ORA was not able to verify the reasonableness of the methodologies used to calculate these emissions to determine if they are consistent with Commission and state policies and law. Therefore, ORA was not able to determine if PG&E's estimated Indirect GHG costs are reasonable, and how they correlate to the procured energy and costs reported under ERRA Tariff Line Items 5.ae, 5.n, and 5.o.[170]

PG&E recorded costs under ERRA Tariff Line Items 5.ae, 5.n, and 5.o in Table 12-1 of PG&E's Testimony totaled [redacted].[171] These costs include estimated Indirect GHG costs from contract purchases (that might not have specific provisions for settlement of GHG costs) with a sub-total of [redacted], as well as GHG costs from contracts with financial settlement with a sub-total of [redacted]. The total of GHG costs associated with these two types of contracts is [redacted].[172] PG&E did not report these GHG costs in a separate ERRA subaccount.[173]

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[167] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet): Tab titled Line 7, and Tab titled Line 17 [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E response received May 23, 2016. See Exhibit1.

[168] *Id.*

[169] PG&E response to ORA data request number 20, question 12. [Confidential] ORA data request issued May 10, 2016. PG&E response received May 23, 2016. See Exhibit 3.

[170] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[171] *Id.*

[172] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet): Tabs titled Line 7, Line 11, Line 17, and Line 18 [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E response received May 23, 2016. See Exhibit 1.

[173] There is no Commission Decision to date requiring utilities to record Indirect GHG costs in a separate ERRA sub-account.

ORA recommends the Commission disallow [redacted] of the costs recorded under ERRA line items 5.ae, 5.n, and 5.o in Table 12-1 of PG&E's Testimony, and approve [redacted] of the total [redacted] recorded under these three tariff line items.[174] Table 7-1 shows a summary of ORA recommendations.

While ORA recommends to the Commission the stated disallowances, ORA expects that PG&E incurred some of these Direct and Indirect GHG costs. However, without sufficient information to verify that PG&E has applied the required methodologies, ORA cannot attest to the reasonableness of the methodologies that PG&E applied to produce its recorded Direct GHG emissions and associated costs, as well as its estimates of some of its Indirect GHG emissions and associated costs. As such, ORA could not determine if PG&E's methodologies were reasonable and consistent with Commission and state polices and law, and to whether the incurred costs were recorded accurately and/or reasonable."

Table 7-1: ORA's Recommendations

Description	Final[175]	ERRA Tariff Line Item[176]	ORA Recommendation
(1) Direct GHG Costs	[redacted]	5.ah	Disallow [redacted]7
(2) Estimated Indirect GHG Cost from CAISO Market Purchases	[redacted]	5.t	Approve [redacted]
(3) Estimated Indirect GHG Costs from Contract Purchases	[redacted]	5.ae, 5.n, and 5.o	Disallow [redacted]
(4) GHG Costs from Contracts with Financial Settlement Costs	[redacted]	5.ae, 5.n, and 5.o	Disallow [redacted]*
* PG&E's recorded cost in ERRA Tariff Line Item 5.t is [redacted]1, which includes the Indirect GHG Cost associated with CAISO Market Purchases of [redacted].[177]			
** PG&E did not provide a breakdown of which contracts were associated with the three listed ERRA Tariff Line Items 5.ae, 5.n, and 5.o.[178]			

[174] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[175] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet): Tabs titled Line 7, Line 11, Line 17, and Line 18 [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E response received May 23, 2016. See Exhibit 1.

[176] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[177] *Id.*

[178] PG&E response to ORA data request number 20, question 12. [Confidential] ORA data request issued May 10, 2016. PG&E response received May 23, 2016. See Exhibit 3.

PG&E's total procured compliance instruments in the 2015 Record Period were about [redacted]) which were within its Direct Compliance Obligation Limit of [redacted].[179] PG&E procured a total of [redacted] in allowances and [redacted] in offsets.[180] Although PG&E's procurement of compliance instruments was within the limit, PG&E's did not provide evidence to support that it operated and managed its GHG program prudently in a least-cost manner (for further discussion, see Section IV. D. 1. of this Chapter).[181]

III. BACKGROUND

A. California ARB's Cap-and-Trade Program

The ARB's Cap-and-Trade program is a market based regulation that is designed to reduce GHG from multiple sources. The program is designed to meet the goal of reducing GHG emissions to 1990 levels by the year 2020. ARB has three main responsibilities under the Cap-and-Trade program: (1) cap GHG emissions by issuing a number of tradeable permits (allowances) equal to the emission cap; (2) reduce the cap over time to reduce emissions to 1990 levels by 2020; and (3) enforce the cap by requiring each entity that operates under the cap to turn in one allowance for every metric ton of carbon dioxide gas equivalent ($MTCO_2e$) that an entity emits.

The Cap and Trade program is structured into three compliance periods:

- First compliance period: 2013-2014
- Second Compliance period: 2015-2017
- Third Compliance period: 2018-2020

Compliance with Cap-and-Trade began in 2013 for electricity generators and large industrial facilities emitting 25,000 $MTCO_2e$ or more annually (covered entities).[182]

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[179] PG&E Advice Letter 4783-E Procurement Transaction Quarterly Compliance Report (Q4 2015). PG&E Workpapers submitted with this Application (A.16-02-019).

[180] *Id.*

[181] In a response to ORA data request, PG&E objected to providing relevant information on what its compliance obligation under the second compliance period of [redacted] PG&E response to ORA data request number 15, question 2. [Confidential] ORA data request issued April 21, 2016. PG&E response received May 05, 2016; and PG&E supplemental response to ORA data request number 15, question 2. [Confidential] ORA data request issued April 21, 2016. PG&E response received May 24, 2016. See Exhibit 2.

[182] Starting in 2015, ARB expanded the program to cover distributors of transportation, natural gas, and other fuels.

Covered entities must report their emissions to CARB annually, which is verified through an independent third-party verification process.

Under ARB regulations, a covered electric utility is subject to specific compliance requirements and obligations.[183] To meet its compliance obligation a utility can use California GHG emission allowances or offset credits (offsets are limited to 8% of an entity's compliance obligation per compliance period). To fulfill a compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year for which an annual compliance obligation is calculated or the last year of a compliance period for which a triennial compliance obligation is calculated.[184] Thus a utility may bank allowances from previous vintage years, but not borrow from future vintage years to meet a compliance obligation. Refer to Table 7-2 for a list of which vintage year allowances a utility may use to meet an annual or triennial compliance obligation.

In addition to the compliance obligation associated with a utility-owned facility (for a facility which emits at least 25,000 $MTCO_2e$ per year), an electric utility is also responsible for imported electricity (if the utility is the compliance entity).[185] Under the Cap and Trade Regulations a utility can apply a Renewable Portfolio Standard (RPS) Adjustment for electric imports from unspecified sources, if the electricity is not directly delivered to California.[186]

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[183] A compliance obligation is the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to ARB.

[184] CCR Section 95856.

[185] Also, an electric utility is responsible for GHG compliance costs for GHG emissions associated with contracts, where a utility has assumed the cost of compliance on behalf of a third-party by either agreeing to compensate a third-party for the cost of their compliance obligations, or procuring compliance instruments on the third-party's behalf.

[186] http://www.arb.ca.gov/cc/capandtrade/meetings/20151214/rpssb350.pdf

Table 7-2: Eligible Allowance Vintage for Cap and Trade Second Compliance Period

Second Compliance Period			
Covered Emissions Year	**Compliance Obligation Due Date**	**Percent of Compliance Obligation Due**	**Eligible Vintages of Allowances**
2015	November 1, 2016	30% of 2015 covered emissions	Vintages 2013-2015, any combination
2016	November 1, 2017	30% of 2016 covered emissions	Vintages 2013-2016, any combination
2017	November 1, 2018	70% of 2015 and 2016, and 100% of 2017 covered emissions	Vintages 2013-2017, any combination

Under ARB reporting requirements, for the 2015 emissions year, facilities and suppliers are required to submit their GHG emissions reports by April 11, 2016 and power entities[187] are required to submit their GHG emissions reports by June 1, 2016. Data verified by independent evaluators are due to ARB on September 1, 2016 and the Cap-and-Trade Compliance deadline is November 1, 2016. Power entities must surrender 30% of their compliance instruments to cover 30% of their qualifying emissions by November 1, 2016. For electric utility data reports, the deadline to make corrections to an RPS Adjustment is July 15, 2016.[188]

B. CPUC Decisions

i) Procurement of GHG Compliance Instruments

Decision (D.) 12-04-046 (Decision on System Track I and Rules Track III of the Long-Term Procurement Plan Proceeding and Approving Settlement) Ordering Paragraph 8 authorizes an electric utility to procure GHG allowances, allowance futures and forwards, and offsets and offset forwards within separately calculated Direct Compliance Obligation

[187] Electric power entities cover retail providers (electric cooperation, such as PG&E), electric service providers (such as, Noble Americas Energy Solutions), local public utilities (such as Sacramento Municipal Utility District), community choice aggregator (such as Marin Energy Authority), Western Area Power Administration (WAPA); electricity importers and exporters; California Department of Water (DWR); and the Bonneville Power Administration (BPA). Electric Power Entity is defined in section 95101(d) of Title 17 of the California Code of Regulations (CCR).

[188] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-dates.htm.

Purchase Limits and Financial Exposure Purchase Limits. This is also reiterated in Appendix 1 of the Decision.[189]

The Direct Compliance Obligation Purchase Limit sets the maximum amount of compliance instruments an Investor-Owned Utility (IOU) is allowed to purchase in a current year. ORA notes that under this framework, an IOU is not allowed to purchase allowances of a vintage older than three years from the current year. The annual Direct Compliance Obligation Purchase Limit is calculated using the following formula:

$$LCY = A + 100\% * FDCY + 60\% * (FDCY + 1) + 40\% * (FDCY + 2) + 20\% * (FDCY + 3)$$

Where:

"L" is the maximum number of GHG compliance instruments an IOU can purchase to meet its direct compliance obligation.

"A" is the utility's net remaining compliance obligation to date," calculated as the sum of the actual emissions for which the utility is responsible for retiring allowances (or purchasing on behalf of a third party) up to the Current Year, minus the total allowances or offsets the utility has purchased up to the Current Year that could be retired against those obligations.

"FD" is the utility's forecasted compliance obligation," the projected amount of emissions the utility is responsible for retiring allowances, or responsible for purchasing on behalf of a third party, calculated using an implied market heat rate (IMHR) that is two standard deviations above the expected IMHR.

"CY" is the current year, i.e., the year in which the utility is transacting in the market.

ii) GHG Emissions

D.14-10-033 as corrected by D. 15-01-024 requires an electric utility to calculate and report its GHG emissions and associated costs using specific conventions and methodologies.[190] A utility incurs GHG costs directly (referred to as "Direct GHG Cost")

[189] "Direct Compliance Obligation" is defined as the tons of emissions for which the utility has an obligation to retire allowances on its own behalf as a regulated entity under the Cap and Trade regime, and/or is otherwise obliged to procure instruments on behalf of a third party that is a regulated entity under the Cap and Trade regime (i.e. contractual arrangements where the IOU is contractually responsible for procuring allowances on a third party's behalf, or could elect to assume that responsibility). Appendix 1, D.12-04-046.

[190] D.15-01-024, Attachment D.

for purchasing compliance instruments for its own Direct GHG emissions under the Cap-and-Trade program and indirectly (referred to as "Indirect GHG Cost") through GHG Cap-and-Trade costs embedded in the price of electricity sold in the wholesale market.

A utility's **Direct GHG emissions**, expressed in metric tons of carbon dioxide equivalents ($MTCO_2e$), could consist of the following sources (refer to Figure 7-1 for a visual depiction of categories of GHG emissions and associated costs methodologies):

(A) **<u>Direct GHG Emissions with Physical Compliance Obligations:</u>**

(1)Utility Owned Generation (UOG): based on actual plant output, a facility-specific heat rate, and ARB-specific emissions fuel factors; and

(2)Energy Imports: Specified imports-based on actual plant output purchased by a utility and specific emissions factors; and Unspecified imports-based on the ARB emission factor for unspecified imports, the ARB transmission loss factor, and any applicable RPS Adjustment.

(B) **Direct GHG Emissions Based on Contractual Obligations:**

(3)Qualifying Facility (QF) Contracts: Physical settled emissions based on actual plant output purchased by a utility and the contract-specific settlement terms; and

(4)Tolling Agreements: based on actual plant output purchased by a utility, the contract-specific heat rate, and ARB-specific emissions factors of fuels.

<u>GHG Emissions Based on Financial Settlement Contracts:</u>

(5)Contracts with Financial Settlements: Emissions from utility contracts in which a utility is responsible for providing the financial settlement specifically for GHG costs (a utility is allowed to record financially settled emissions as Direct or Indirect emissions).

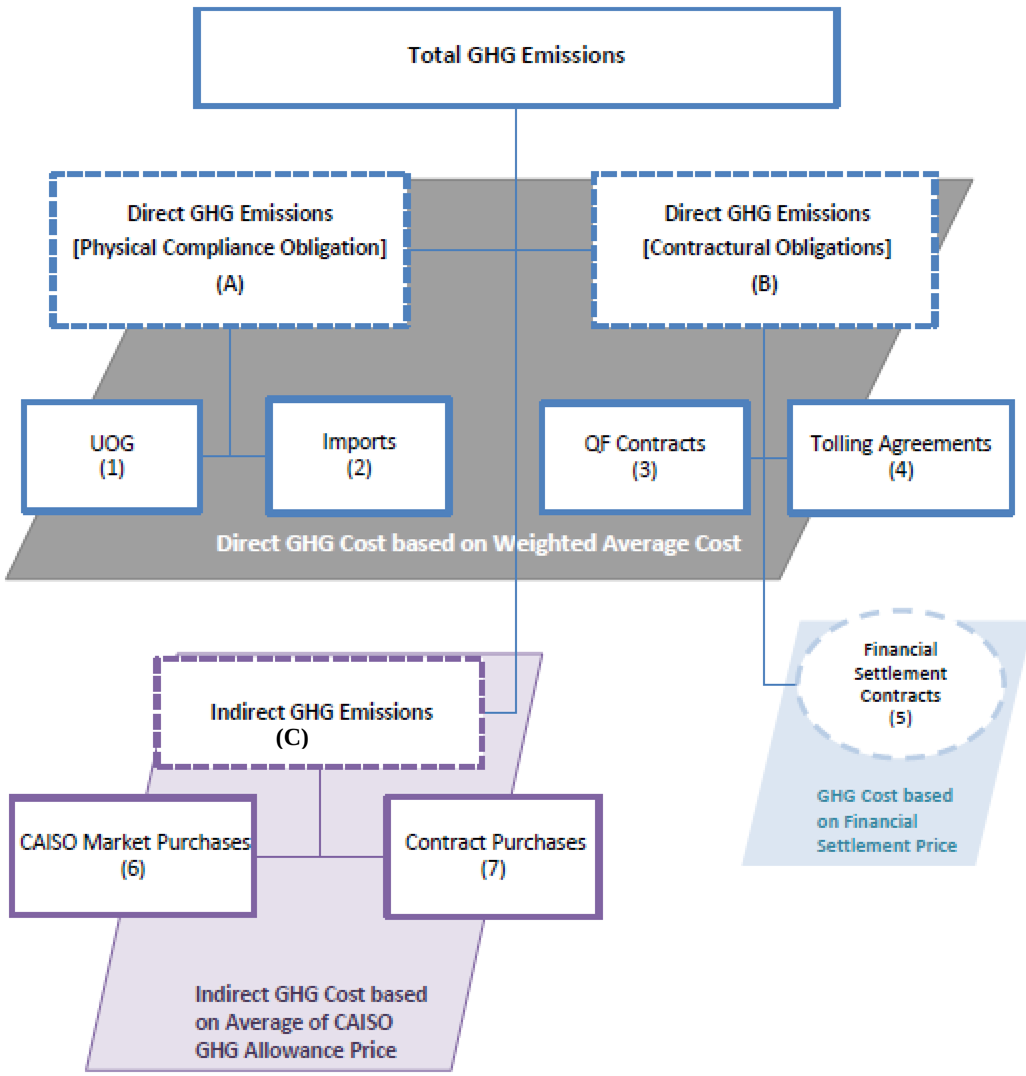
(C) **Indirect GHG Emissions:**

A utility's **Indirect GHG emissions**, expressed in $MTCO_2e$, could consist of the following sources (See Figure 7-1):

(6)CAISO Market Purchases: Emissions based on net market energy purchases and either ARB's emission factor for a generic system or market heat rate-implied emission factor; and

(7) Contract Purchases: Emissions based on actual plant output purchased by the utility and contract-specific settlement terms.

Figure 7-1: Schematic of Direct and Indirect GHG Emissions and Methodology to Calculate Associated Costs by Type of Source



iii) GHG Emissions Costs

D.14-10-033 as corrected by D.15-01-024 requires an electric utility to calculate the "recorded" costs associated with GHG emissions covered by compliance obligations under the Cap-and-Trade program using the following methodologies:

(A) Direct GHG Costs:

The recorded Direct GHG costs are the sum of each month's Weighted Average Costs (WAC) of compliance instruments inventory multiplied by that month's actual Direct emissions for which the utility has a physical compliance obligation.[191] Thus, the Direct GHG costs, in a given month's WAC, could be based on GHG emissions from a utility's UOG, imports, tolls, and contracts, where a utility has physical compliance obligations for such emissions under Cap-and-Trade program.

GHG costs associated with financially settled tolling agreements are based on actual contract settlement, not on WAC. Therefore, emissions and costs associated with financially settled tolling agreements are not included when calculating the WAC or the Direct GHG costs, which are based on monthly emissions.[192]

For the purpose of WAC calculations, a utility calculates the WAC based on its inventory of all allowances and offsets which are eligible to meet the compliance obligation for the current compliance period under the Cap-and-Trade program. For instance, when calculating the WAC for 2015, a utility shall calculate its WAC based on inventory of allowances with vintage years 2015, 2016, and 2017, plus any 2013 and 2014 allowances that were not used to meet its obligation in the first compliance period. ARB does not restrict which vintage year of offsets a utility can use to meet a compliance obligation.

(B) Indirect GHG Costs:

The recorded Indirect GHG costs equal the total of Indirect GHG emissions (CAISO market purchases and contract purchases that do not include explicit provisions for GHG costs) multiplied by the annual average of the CAISO's daily GHG Allowance Price Index. The CAISO GHG Allowance Price Index is computed by averaging the published daily price for the recorded year and dividing by the number of days in that year.

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[191] D. 15-01-024 Attachment C. pages 1-4.

[192] Direct Cost for Tolling Agreements with financial settlements = Settlement Price * Emissions Quantity; where settlement price is the unit price at which the utility will financially compensate its tolling counterparty for GHG emissions (usually the ARB auction clearing price); and Emissions Quantity is the emissions obligation for the entire month calculated in accordance with the tolling agreement. *Id*. page 5.

IV. DISCUSSION

ORA conducted thorough discovery and reviewed PG&E's Application and workpapers to verify if PG&E correctly applied the methodologies required by ARB regulations and the relevant Commission Decisions,[193] and to determine if PG&E recorded its GHG emissions and costs accurately. To conduct the review, ORA compared ERRA entries (procured energy (GWh) and associated costs), which are recorded in the various ERRA Tariff Line items in Table 12-1, Chapter 12 of PG&E's Testimony,[194] with PG&E's reported entries of Direct and Indirect GHG emissions and associated costs.

Through discovery request, ORA asked that PG&E produce the methodologies, assumptions, and calculations for its recorded GHG emissions (Direct and Indirect). ORA wanted to verify that PG&E applied the required methodologies correctly to calculate GHG emissions; to correlate the energy procured from various sources (as recorded in ERRA accounts in Table 12), with the energy that PG&E used to calculate the GHG emissions; and to ensure that PG&E's GHG costs are reasonable and recorded accurately under the relevant ERRA accounts.

PG&E's Direct GHG costs (GHG compliance costs associated with emissions from PG&E's facilities, tolling agreements, QFs, and imports) were reported under the ERRA GHG Subaccount (Line Reference "5-ah"). PG&E's workpapers associated with Chapter 12 included PG&E's direct GHG costs for the 2015 Record Year.[195] PG&E did not include a separate ERRA subaccount for Indirect GHG costs.

Although D.14-10-033 does not require a utility to record Indirect GHG costs in a separate ERRA subaccount, the decision requires a utility to track GHG costs separately for reference purpose using a specific template.[196] The decision also requires a utility to describe "the methodology used to make these calculations in detail sufficient for interested

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[193] For further discussion, refer to Section III. A. and III. B. of this Chapter.

[194] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[195] *Id.*

[196] D. 14-10-033 page 35. Note that the template (D-2) referenced in D.14-10-033 is corrected in D.15-01-033, which is used to include forecasted and recorded (actual), Direct- and Indirect-GHG emissions and associated costs. D.15-01-033, Attachment D, Template D-2 pages 7-11.

parties and the Commission to determine whether the methodology was reasonable and consistent with Commission and state policies and law."[197]

PG&E's workpapers for Chapter 12 indicate that the total GHG procurement costs for PG&E's GHG compliance instrument transactions under the California cap-and-trade program pursuant to AB 32 for the 2015 Record Year are [redacted].[198] As of December 2015, PG&E Weighted Average Cost was [redacted] and the Direct GHG emissions for the period were reported as [redacted] $MTCO_2e$.[199] However, PG&E's workpapers did not include details on how the GHG emissions (Direct and Indirect) were derived from the amount of energy PG&E procured. The workpapers also did not include how the GHG unit cost used to calculate the GHG costs was derived.

The workpapers recorded monthly Direct GHG emission entries (related to PG&E's facilities, tolling agreements, and imports), as well as the total Direct GHG costs (based on a Weighted Average Costs value).

ORA asked PG&E whether it is seeking cost recovery for GHG costs (Direct and Indirect) and requested that PG&E provide the workpapers associated with GHG costs included in this Application (A.16-02-019) for the purpose of cost recovery.[200] PG&E stated that "[redacted]."[201] PG&E also stated that,

> "[redacted]

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[197] D.14-10-033, page 26.

[198] PG&E Testimony, Chapter 12, Table 12-1, line 5.ah. (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[199] PG&E Testimony, Chapter 12, ERRA Activity Reports-December (Tab: AE1) Emissions] [Confidential] (Workpaper submitted with PG&E's Application 16-02-019). ORA notes that PG&E's emission and expenses data in this spreadsheet image (not a working spreadsheet with calculations).

[200] ORA Data Request No. 15, issued on April 21, 2016.

[201] PG&E response to ORA data request number 15, question 01 [Confidential]. ORA Data Request Issued April 21, 2016. PG&E response received May 23, 2016. See Exhibit 1.

[redacted].”[202]

PG&E responses did not include workpapers showing the calculations of Direct and Indirect GHG costs, as requested.[203] ORA provided PG&E with a spreadsheet template to produce the GHG emissions (Direct and Indirect) and associated costs. With this template, ORA specified that PG&E should also provide all calculations and any workpapers used to fill in the spreadsheet. PG&E provided the spreadsheet, recording GHG emissions and associated costs; however, PG&E did not include any information or calculations explaining how it derived its recorded GHG emissions.[204]

ORA reviewed PG&E's workpapers to compare PG&E's forecasted GHG emissions and associated costs for 2015 (A.14-05-025), approved in D.14-12-053, to PG&E's final (actual) GHG emissions and associated costs for the 2015 Record Period. Table 7-3 shows a comparison between PG&E's Forecasted and the Final Direct GHG emissions and associated GHG costs, and Indirect GHG emissions and associated GHG costs, for the 2015 Record Period.[205]

As shown in Table 7-3, PG&E's Final Direct GHG emissions were about [redacted] than the emissions forecasted in PG&E's 2015 ERRA Forecast Application. PG&E's Final Indirect emissions were about [redacted] than forecasted. The total Final GHG emissions (Direct and Indirect) were about [redacted] higher than forecasted.[206]

PG&E's estimated Final *Indirect* GHG costs (GHG costs embedded in the price of energy purchases) were [redacted] as much as the Final *Direct* GHG costs.

[202] *Id.* PG&E response to Question 1, b. [Confidential].

[203] *Id.* PG&E response to Question 1 a. through k [Confidential].

[204] Id. PG&E response to Question 1. L (spreadsheet) [Confidential].

[205] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

[206] *Id.*

As shown in Table 7-3, PG&E's Final Total Direct GHG cost ([redacted] was [redacted] or [redacted], than its forecasted GHG cost of [redacted].[207] In a response to ORA's data request, PG&E stated that,

> "[redacted]."[208]

The estimated Final Total Indirect GHG Cost ([redacted]) was about [redacted] or [redacted] than forecasted. The GHG costs associated with contracts with financial settlement were [redacted]. PG&E did not include forecast values for emissions/costs associated with these contracts, and did not provide a reason as to why it did not forecast emissions from these contracts with financial settlements.[209]

PG&E's total GHG costs (Direct and Indirect) were about [redacted], which was about [redacted] or [redacted] than forecasted.

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[207] *Id.*

[208] ORA requested that PG&E provide errata to its original workpaper to Table 12-1 submitted with its application because PG&E's initial explanation included irrelevant explanation regarding the variance stating that [redacted] PG&E response to ORA data request number 20, question 03, "ERRA-2015-PGE-Compliance_DR_ORA_020-Q03Atch01-CONF." ORA data request issued May 10, 2016. PG&E response received on May 23, 2016.

[209] BPG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

Table 7-3: PG&E's Claimed Forecasted and Final GHG Emissions and Associated Costs[210]

Description	Forecast	Final	Variance	Percent Variance
(1) Total Direct GHG Emissions	[redacted]	[redacted]	[redacted]	[redacted]
(2) Total Indirect Emissions	[redacted]	[redacted]	[redacted]	[redacted]
(3) Contracts with Financial Settlements	-	[redacted]	[redacted]	[redacted]
Total GHG Emissions (MTCO2 e)	[redacted]	[redacted]	[redacted]	[redacted]
Direct GHG Costs (1)	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total GHG Costs	[redacted]	[redacted]	[redacted]	[redacted]

A. PG&E Did Not Substantiate its Calculation of the Direct GHG Emissions

ORA issued multiple data requests to verify the accuracy of PG&E's Direct GHG emissions and associated costs and determine whether PG&E is in compliance with Commission's rules and ARB regulations.

In response to ORA's data request, PG&E provided a breakdown of the sources of Direct GHG emissions associated with its owned-facilities, tolling agreements, QF contracts, and imports, for the 2015 Record Period.[211] However, PG&E did not provide the calculations used to generate these Direct GHG emissions from the procured energy from these sources.

As explained in sections (III.A.) and (III.B.) of this Chapter, D. 15-01-024, requires a utility to calculate GHG emissions using specific methodologies and conventions. For instance, recorded (final) GHG emissions from a utility owned generation facility, is calculated from actual plant output, facility-specific heat rate assumptions, and ARB-

[210] *Id.*

[211] PG&E's Direct GHG emissions from its owned-facilities [redacted] *Id.*

specified emissions factors for fuels.[212] On the other hand, the Decision requires a utility to calculate emissions from tolling agreements using actual plant output purchased by the utility, the contract-specific heat rate assumption and ARB-specified emission factors for fuels.

Table 7-4 shows a summary of PG&E's Direct GHG emissions (Final and Forecasts values), as well as associated Direct GHG costs, from PG&E's utility-owned facilities, tolling agreements, imports and QF contracts.[213]

Table 7-4: PG&E's Direct GHG Emissions and Costs[214]

	Forecast	Final	Variance	Percent Variance
UOGs (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
Tolling Agreements (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
QF Contracts (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
Imports (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
Total Direct GHG Emissions (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
Direct GHG Costs	[redacted]	[redacted]	[redacted]	[redacted]

i) PG&E Did Not Substantiate its Calculation of the Direct GHG Emissions from PG&E-Owned Facilities

D.15-01-024 requires an electric utility to calculate Direct GHG emissions using specific methodologies (see Section III. B. 1. of this Chapter).

Additionally, ARB regulations require a "covered" power entity (facility emitting 25,000 $MTCO_2e$ or more annually) to calculate GHG emissions using specific methodologies.[215] For instance, a power entity must calculate its GHG emissions for electricity obtained from specified facilities or units, using the following equation:

[212] D. 15-01-024, Attachment D. page 8.

[213] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

[214] *Id.*

[215] CCR Section 95111 (b). http://www.oal.ca.gov/CCR.htm .

$$CO_2e = MWh \times TL \times EF_{sp}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EFsp = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website.[216]

TL = Transmission loss correction factor.[217]

ORA issued multiple data requests to PG&E requesting information on how PG&E calculated its Direct and Indirect GHG emissions and their associated costs.

In response to ORA's data requests, PG&E provided some information regarding how it estimated its Indirect GHG emissions and costs, specifically how it estimated the GHG emissions and associated costs from energy procured through market and contract purchases.[218] ORA noted that PG&E provided inconsistent estimates for Indirect GHG emissions and costs that PG&E provided in response to two data requests, and issued a data request inquiring about the inconsistency.[219] PG&E provided a response indicating that it inadvertently excluded certain contracts in one of the responses.[220]

However, PG&E failed to provide information on how Direct GHG emissions were derived from energy procured from its own facilities and tolling contracts.[221] Therefore, ORA was not able to verify if PG&E is in compliance with Commission's rules and ARB regulations, and determine if PG&E's claim for the associated Direct GHG costs are accurate or reasonable.

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[216] EFsp is zero for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation.

[217] TL = 1.02 to account for transmission losses associated with generation outside of a California balancing authority; or TL = 1.0 if the reporting entity provides documentation that demonstrates to the satisfaction of the verifier and ARB that transmission losses (1) have been accounted for, (2) are supported by a California balancing authority, or (3) are compensated by using electricity sourced from within California. I*bid*

[218] PG&E response to ORA data request number 08, question 4. Including spreadsheet attachment 01, [Confidential]. ORA Data Request Issued March 24, 2016. PG&E Response received April 15, 2016.

[219] ORA data request number 23, question 5. issued June 9, 2016.

[220] PG&E response to ORA data request number 23, question 5. Response received on June 23, 2016.

[221] PG&E response to ORA data request number 08, question 4, including spreadsheet attachment 01, [Confidential]. ORA Data Request Issued March 24, 2016. PG&E Response received April 15, 2016. Also, PG&E ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

ii) PG&E Did Not Substantiate the Calculation of the Direct GHG Emissions from its Tolling Agreements

D.15-01-024 requires an electric utility to calculate Direct GHG emissions associated with energy procured from tolling agreements using actual plant output purchased by a utility, the contract-specific heat rate, and ARB-specific emissions factors of fuels. For tolling agreements, a utility might transfer compliance instruments to its counterparties.

PG&E did not produce the calculations used to derive the GHG emissions associated with the energy procured from its tolling agreements. PG&E reported GHG emissions from [redacted]. ORA was not able to verify PG&E's calculations of these emissions, nor could it determine which tolling agreements were associated with these sources.[222] As such ORA was not able to verify if PG&E is in compliance with Commission's rules and ARB regulations, and determine if PG&E's claim for the associated Direct GHG costs are accurate or reasonable.

iii) PG&E Did Not Substantiate its Calculation of Direct GHG Emissions from its Qualifying Facility Contracts

D.15-01-024 requires an electric utility to calculate Direct GHG emissions associated with energy procured from QF Contracts using actual plant output purchased by a utility and the contract-specific settlement terms (physically settled emissions).

In its response to ORA's data request, PG&E reported GHG emissions from [redacted] However, PG&E did not produce the calculations used to derive the GHG emissions associated with the energy procured from this contract.[223] As such ORA was not able to verify if PG&E is in compliance with Commission's rules and ARB regulations, and determine if PG&E's claim for the associated Direct GHG costs are accurate or reasonable.

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[222] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1. PG&E did not provide any narrative and/or data dictionary to explain the entries in a spreadsheet that it provided in response to ORA data request. PG&E provided a list of acronyms for sources accompanied with log numbers. ORA noticed that there are multiple entries with the same log number, and assumed that these entries belong to the same tolling agreement. As such, ORA is not able to verify the number (or source contracts) of the tolling agreements associated with the entries in the spreadsheet.

[223] *Id.*

iv) The Commission Should Disallow PG&E's Claim for Cost Recovery in ERRA GHG Subaccount

Despite multiple data requests and Meet and Confer meetings, ORA was not able to verify the calculations of PG&E's reported emissions from its facilities and tolling agreements. PG&E maintains that the process to derive the emissions is too complicated to reproduce:

> "[redacted]."—

Given PG&E's failure to substantiate how it calculated the Direct GHG emissions from its procured energy during the 2015 Record Period, ORA cannot verify whether PG&E's Direct GHG emissions were accurate, nor is it able to determine whether PG&E applied the Commission and/or ARB required methodologies to calculate these emissions. As such, ORA cannot attest to whether PG&E's entries in ERRA GHG subaccount (Tariff Line Item 5.ah.) for 2015 are accurate, let alone reasonable. Therefore, the Commission should disallow PG&E's claim for cost recovery of Direct GHG costs, which totals to [redacted][225]

B. PG&E Did Not Substantiate Its Calculation Of The GHG Emissions From Contracts With Financial Settlement Provisions For GHG Costs

D.15-01-024 Decision requires a utility to calculate the GHG cost associated with financial settlement contracts (contracts that contain explicit provisions for GHG costs) as follows:[226]

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[224] To clarify ORA did not ask for a single spreadsheet but asked for PG&E's calculations of its Direct GHG emissions. Email communication received from PG&E in response to ORA inquiry regarding incomplete information provided by PG&E in response to ORA data requests (missing calculations of Direct GHG emissions) (email title: Follow-up call on supplemental to DR15, Q2). Email communication, sender: Leslie Almond, receiver: Ayat Osman, June 20, 2016.

[225] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[226] *Id.*

Direct Cost = Settlement Price × Emission Quantity

Where,

"Settlement Price," is the unit price at which the utility will financially compensate its tolling counterparty for GHG emissions (usually the ARB Auction Clearing Price); and

"Emission Quantity" is the emissions obligation for the entire month calculated in accordance with the tolling agreement.

The decision allows a utility to record financial settled emissions as Direct or Indirect emissions. The decision requires that the utility exclude the GHG costs associated with these contracts from the calculation of the WAC.[227] The WAC is used to calculate Direct GHG costs for which a utility has physical compliance obligations.

In response to ORA's data request, PG&E produced GHG emission values and monthly costs for [redacted] contracts with financial settlements. PG&E reported a total of [redacted] with an associated GHG cost of [redacted].[228] In a response to ORA's data request, PG&E indicated that the GHG costs for the contracts with financial settlements are recorded under three ERRA accounts (Tariff Line Items 5ae, 5n, 5o).[229] However, PG&E did not specify which contracts were associated with which Tariff Line Item.

In addition, although PG&E recorded final emissions and costs for these contracts with financial settlements in this application, PG&E did not include values for forecasted GHG emissions or costs from these contracts. PG&E did not explain why it did not forecast emissions or costs for these contracts.

The spreadsheet did not include calculations that PG&E used to determine the GHG emissions and the associated costs associated with the energy procured through these contracts, nor did PG&E provide the contract terms that were used to calculate the costs, as required by D.15-01-024. ORA was not able to correlate the energy procured under these

[227] D.15-01-024, Attachment C, p. 5.

[228] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1. PG&E did not provide any narrative and/or data dictionary to explain the entries in a spreadsheet that it provided in response to ORA data request.

[229] PG&E response to ORA data request number 20, question 12. [Confidential] ORA data request issued May 10, 2016. PG&E response received May 23, 2016. See Exhibit 3.

three Tariff line items (Tariff Line Items 5ae, 5n, 5o in Table 12-2 of PG&E's Testimony) [230] with the energy procured from these contracts with financial settlements, nor was it able to determine if PG&E's calculations of GHG emissions and costs were accurate, let alone reasonable.

C. PG&E Did Not Substantiate the Calculation of the Indirect GHG Emissions

Decision 14-10-033 requires the electric utilities to calculate the Recorded Indirect GHG cost as follows:[231]

> Recorded Indirect GHG Costs = CAISO Proxy Price × Estimated Indirect GHG-Emissions
>
> Where,
>
> "CAISO Proxy Price" is the annual average of the CAISO GHG Allowance Price Index for the current year.
>
> "Estimated Indirect GHG Emissions" is the utility's estimated actual annual emissions associated with wholesale market electricity purchases and contracts that do not have a specific provision for settlement of GHG costs.

Decision 14-10-033 further requires the utility to describe "the methodology used to make these calculations in detail sufficient for interested parties and the Commission to determine whether the methodology was reasonable and consistent with Commission and state policies and law."[232]

D.15-01-024 requires a utility to calculate Indirect GHG costs associated with GHG emissions from: (a) CAISO Market Purchases: Emissions based on net market energy purchases and either ARB's emission factor for generic system power or market heat rate-implied emission factor; and (b) Contract Purchases: Emissions based on actual plant output purchased by the utility and contract-specific settlement terms.

Although D.14-10-033 requires a utility to report Indirect GHG emissions and associated costs as a separate line item in the utilities forecast applications, it does not require the utility to present Indirect GHG costs in a separate ERRA subaccount.

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[230] PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's A.16-02-019). [Confidential].

[231] D.14-10-033, pp. 25-26.

[232] *Id.*, p. 26.

In a response to ORA's data request, PG&E provided estimates of Indirect GHG emissions associated with CAISO market and contract purchases, and the associated estimated Indirect GHG costs.[233] PG&E estimated that the final total Indirect GHG costs was [redacted] with about [redacted] associated with CAISO market purchases, and about [redacted] associated with contract purchases.[234]

ORA noted discrepancies in PG&E's responses to data requests where PG&E reported significantly different costs under different responses. Such discrepancies in PG&E's responses triggered ORA to further investigate PG&E's calculations to ensure that the costs are estimated reasonably and recorded accurately. For instance, PG&E provided conflicting cost entries in responses to two of ORA's data requests: in one response, PG&E 's estimate of Indirect GHG costs associated with CAISO purchases was [redacted],[235] whereas in another response, PG&E's estimate of the Indirect GHG costs associated with the same source was about [redacted],[236] a difference of about [redacted]. In another instance, PG&E reported Indirect GHG costs (associated with a certain category of contract purchases) as [redacted],[237] whereas in a response to another data request, PG&E reported the costs associated with the same sources were about [redacted],[238] a difference of about [redacted]. Therefore, without sufficient details as to the assumptions and methodologies that PG&E used to produce its recorded costs, ORA is not able to verify the accuracy of such entries, let alone the reasonableness of PG&E's costs. Table 7-5 shows a comparison of PG&E's forecasted and final Indirect GHG emissions, and associated Indirect GHG costs.

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[233] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. See Exhibit 1. PG&E Response received May 23, 2016. PG&E did not provide any narrative and/or data dictionary to explain the entries in a spreadsheet that it provided in response to ORA data request.

[234] *Id.*

[235] *Id.*

[236] PG&E response to ORA data request number 08, question 4, including spreadsheet attachment 01, [Confidential]. ORA Data Request Issued March 24, 2016. PG&E Response received April 15, 2016.

[237] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. See Exhibit 1. PG&E Response received May 23, 2016. PG&E did not provide any narrative and/or data dictionary to explain the entries in a spreadsheet that it provided in response to ORA data request.

[238] PG&E response to ORA data request number 08, question 4, including spreadsheet attachment 01, [Confidential]. ORA Data Request Issued March 24, 2016. PG&E Response received April 15, 2016.

Table 7-5: PG&E's Indirect GHG Emissions and Associated Costs[239]

	Forecast	Final	Variance	% Variance
Indirect GHG Emissions-Net CAISO Market Purchases (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
(a) Indirect GHG Emissions-Contract Purchases (SRAC) (MTCO2e)	[redacted]	[redacted]		
(b) Indirect GHG Emissions Contract Purchases (Fixed Price) (MTCO2e)	[redacted]	[redacted]		
Total Indirect GHG Emissions Contract Purchases (MTCO2eq) (a + b)	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total Indirect GHG Emissions (MTCO2e)	[redacted]	[redacted]	[redacted]	[redacted]
Indirect GHG Cost-Net CAISO Market Purchases	[redacted]	[redacted]	[redacted]	[redacted]
(a) Indirect GHG Cost-Contract Purchases (SRAC)		[redacted]		
(b) Indirect GHG Cost-Contract Purchases (Fixed Price)		[redacted]		
Total Indirect GHG Cost-Contract Purchases (a + b)	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total Indirect GHG Cost	[redacted]	[redacted]	[redacted]	[redacted]

PG&E's estimated final total Indirect GHG emissions and associated costs were about [redacted] than forecasted. The estimated Indirect GHG costs associated with CAISO market purchases were about [redacted] than forecasted; whereas, the Indirect GHG costs associated with contract purchases were about [redacted] than forecasted.

i) PG&E Did Not Substantiate its Calculation of the Indirect GHG Emissions from CAISO Market Purchases But These Costs were Reasonable

In a response to ORA's data request, PG&E indicated that the Indirect GHG cost associated with CAISO market purchases was embedded in the costs recorded in ERRA tariff line item 5t in Table 12-2 of PG&E's Testimony.[240]

Although PG&E did not provide the calculations used to derive the Indirect GHG emissions associated with CAISO market purchases, ORA estimated the energy procured

[239] *Id.*

[240] PG&E response to ORA data request number 20, question 12. [Confidential] ORA data request issued May 10, 2016. PG&E response received May 23, 2016. See Exhibit 3.

from market purchases. To estimate the energy corresponding to PG&E's reported emissions,[241] ORA used ARB default emission factor for unspecified sources (0.428 $MTCO_2e$/MWh). ORA estimated PG&E's energy procured from CAISO market purchases as [redacted].[242] To verify the energy procured from CAISO market purchases, ORA compared this estimated value [redacted] with PG&E's entries in Table 12-1 [redacted].[243]

ORA applied the annual average of the CAISO GHG Allowance Price Index for 2015 of $12.79/MWh to the total energy procured from CAISO market, which was reported in Table 12-2 of PG&E Testimony.[244] ORA estimates that the Indirect GHG costs associated with PG&E's CAISO market purchases were [redacted].[245] PG&E reported its final Indirect GHG costs for CAISO market purchases as [redacted].[246]

Based on this analysis, ORA concludes that PG&E's estimates of the final Indirect GHG costs associated with energy procured from CAISO market purchases, which are imbedded in the costs reported under ERRA Tariff Line 5t, are reasonable.

ii) PG&E Did Not Substantiate its Calculation of the Indirect GHG Emissions from Contract Purchases

In a response to ORA's data request, PG&E indicated that the Indirect GHG cost associated with contract purchases (such contracts might not have specific settlement provisions for GHG costs) were recorded in ERRA tariff line items 5ae, 5n and 5o in Table

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[241] PG&E total recorded the final Indirect GHG emissions associated with CAISO market purchases as [redacted]5 $MTCO_2e$ [PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

[242] ORA estimated the energy procured as follows: Energy procured from CAISO purchase (GWh) = ([redacted] $MTCO_2e$ * 0.428 $MTCO_2eq$/MWh)/1000 MWh/GWh = [redacted]

[243] PG&E's entries in Confidential Table 12-1, indicate a total of [redacted] for Market Purchases including two tariff line items: *5c and 5t;* Other entries in the spreadsheet (Retail_ISO_2015_12_Final, but not labelled as 5.t.) indicate a value of [redacted] (Cell D88, Spreadsheet Tab labelled "Load"). ORA assumed that that value present PG&E's final energy procured from CAISO market purchases. [PG&E Testimony, Chapter 12, Table 12-1 (Workpaper submitted with PG&E's Application 16-02-019). [Confidential]

[244] *Id.*

[245] ORA estimated Indirect GHG Cost [CAISO market purchases]: $12.79/MWh * [redacted] = [redacted]

[246] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

12-2 of PG&E's Testimony.[247] PG&E did not specify which contracts were associated with which tariff line items. ORA reviewed entries for ERRA tariff line items 5ae, 5n and 5o in Table 12-2, labelled as QF. Table 12-2 indicates that the total procured energy from QFs was [redacted].[248]

In a response to ORA's data request, PG&E provided estimates of Indirect GHG emissions listing [redacted] sources; however, it is not clear how many contracts were associated with these sources. PG&E separated the list of these contracts into two groups: [redacted] or [redacted].”[249]

PG&E listed [redacted] sources under the [redacted]) with associated cost of [redacted][250] PG&E appears to have applied the methodology required in D.14-10-033, to estimate the Indirect GHG cost associated with [redacted].” That methodology requires a utility to multiply the estimated Indirect GHG emissions, associated with energy procured from contracts purchases with no explicit provision for financial settlement for GHG costs, by the applied the annual average of the CAISO GHG Allowance Price Index for the current year, which was $12.79/MWh for the 2015 Record Year.

PG&E listed 55 sources under the [redacted] (totaling [redacted] with associated cost of $[redacted].[251] PG&E appears to have applied a cost of [redacted] to estimate the costs associated with these contracts.

PG&E failed to provide its calculations of Indirect GHG emissions relative to the procured energy from these contracts. As such ORA was not able to correlate the energy procured under the PG&E's ERRA tariff line items 5ae, 5n and 5o in Table 12-2 of

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[247] PG&E response to ORA data request number 20, question 12. [Confidential] ORA data request issued May 10, 2016. PG&E response received May 23, 2016. See Exhibit 3.

[248] PG&E Testimony, Chapter 12, Table 12-1 [Tab: Summary] (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[249] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

[250] *Id.*

[251] *Id.*

PG&E's Testimony with PG&E's Indirect GHG estimates, which PG&E provided in its response to ORA data request.[252]

Therefore, ORA is not able to attest as to the accuracy or reasonableness of the estimates of Indirect GHG costs, which are embedded in the costs recorded under ERRA Tariff Line Items 5ae, 5n and 5o in Table 12-2 of PG&E's Testimony.[253]

iii) The Commission Should Allow PG&E to Recover Costs for Indirect GHG Costs Associated with CAISO Market Purchases and Disallow Cost Recovery of Indirect GHG Costs Associated with Contract Purchases

Based on its analysis, ORA concludes that PG&E's final Indirect GHG costs associated with energy procured from CAISO market purchases, recorded under ERRA Tariff Line 5t, are reasonable. PG&E recorded a total of [redacted] under ERRA Tariff Line 5t,[254] which includes PG&E's estimated Indirect GHG costs associated with CAISO market purchases of [redacted].[255]

However, PG&E did not substantiate how it estimated its Indirect GHG emissions from the energy procured from these contract purchases. PG&E recorded a total of [redacted] under lines 5ae, 5n and 5o,[256] which includes PG&E's estimated Indirect GHG costs of [redacted] associated with contract purchase.[257] ORA is not able to verify the accuracy of PG&E's estimated GHG emissions for these contract purchases.

As such, ORA recommends that the Commission disallow cost recovery for [redacted], based on PG&E's estimates of Indirect GHG costs associated with these

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[252] *Id.*

[253] PG&E Testimony, Chapter 12, Table 12-1 [Tab: Summary] (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[254] *Id.*

[255] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

[256] PG&E Testimony, Chapter 12, Table 12-1 [Tab: Summary] (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

[257] PG&E response to ORA data request number 15, question 01, l. attachment 02, (Spreadsheet) [Confidential]. ORA Data Request (including ORA Spreadsheet Template) Issued April 21, 2016. PG&E Response received May 23, 2016. See Exhibit 1.

contract purchases.[258] Since PG&E did not report these Indirect costs in a separate ERRA subaccount, ORA recommends that the Commission approve a total of [redacted] under ERRA Tariff Lines 5ae, 5n and 5o, by deducting the Indirect GHG costs of contract purchases of [redacted] from the total recorded costs of [redacted] under ERRA Tariff Lines 5ae, 5n and 5o.[259]

D. PG&E's Procurement of GHG Compliance Instruments and Associated Costs

i) PG&E did not Provide Evidence that It Has Operated and Managed its GHG Program in the Most Cost-Effective Manner

The 2015 Record Year is the first year of the Cap-and-Trade Second Compliance period that spans 2015, 2016 and 2017. As discussed in Section III.A. of this Testimony, ARB regulations allow a utility (covered entity) to procure compliance instruments to meet its compliance obligation per compliance period based on specific restrictions. For example, a utility is permitted to use allowances with 2013, 2014 and 2015 Vintages but not borrow from future vintages (such as, 2018 vintage) to meet its obligations for the 2015 emission year. In addition, a utility may only use offsets to meet up to 8% of its compliance obligation. For example, PG&E can use offsets to meet up to 8% of its total 2015, 2016 and 2017 compliance obligations.

The Commission established a Direct Compliance Obligation Limit, to allow utilities reasonable flexibility in procuring compliance instruments, thus avoiding under-procurement or non-compliance, while limiting ratepayer exposure to extra costs, and avoiding over-procurement. Refer to Section III. B. 1. of this Chapter for discussion of the Direct Compliance Obligation Limit.

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[258] *Id.*

[259] PG&E Testimony, Chapter 12, Table 12-1 [Tab: Summary] (Workpaper submitted with PG&E's Application 16-02-019). [Confidential].

PG&E's Direct Compliance Obligation Limit applicable to the year 2015 was [redacted] $MMTCO_2e$ based on its Commission approved 2014 BPP.[260] PG&E's base case forecasted emissions for 2015 through 2018, was [redacted] $MMTCO_2e$, as shown in table 7-6.[261]

Table 7-6: PG&E's Forecasted 2015-2018 GHG Emissions and 2015 Direct Compliance Obligation Limit[262]

	Net Remaining Compliance Obligation	2015	2016	2017	2018	Total
Forecasted Emissions (Base Case) in MMTCO2e		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Direct Compliance Purchase Limit for 2015 in MMTCO2e	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

PG&E's total procured compliance instruments in the 2015 Record Year of [redacted] was within its direct compliance obligation limit of [redacted]. PG&E procured a total of [redacted] of allowances,[263] and [redacted] of offsets.[264] Although PG&E is allowed to procure future vintage allowances (2018 Vintage), it cannot use those allowances to meet the compliance obligation for the Cap-and-Trade Second Compliance period. For 2015, PG&E is allowed to use any combination of allowances with vintages 2013 through 2015 (there are no restrictions on vintages for offsets). Table 7-7 shows PG&E's procured Compliance Instruments in 2015.

[260] PG&E's Direct Compliance Obligation Limit for 2015 is calculated using a formula established in D.12-04-046. This calculation is based on its forecasted emissions including: 100% of its 2015 forecast, 60% of its 2016 forecast, 40% of its 2017 forecast, and 20% of its 2018 forecast, plus any carryover of compliance instruments from 2013-2014 Compliance period. This limit was two standard deviations higher than the expected Implied Market Heat Rate (IMHR) or base case (Refer Section III. B. 1. of this Chapter for formulae used in the calculation). Reference: PG&E Advice Letter 4507-E [CONFIDENTIAL], Appendix L page 303.

[261] *Id.*

[262] *Id*

[263] PG&E indicated that it [redacted], but did not provide an explanation. PG&E response to ORA data request number 7, question 8. [Confidential] ORA data request issued March 28, 2016. PG&E response received April 08, 2016.

[264] PG&E Advice Letter 4783-E [Procurement Transaction Quarterly Compliance Filing (Q4, 2015). Source: PG&E Workpapers submitted with this Application.

Table7- 7: PG&E's Procured GHG Compliance Instruments in Record Year 2015[265]

Quarter	Vintage of Allowance Purchased (MTCO2e)			Offset Purchases (MTCO2e)	Total Compliance Instruments Purchased (MTCO2e)
	2013 and Prior	2015	2018		
Q1 2015		[redacted]	[redacted]	[redacted]	[redacted]
Q2 2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Q3 2015		[redacted]	[redacted]	[redacted]	[redacted]
Q4 2015		[redacted]	[redacted]	[redacted]	[redacted]
Total in 2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

PG&E forecasted a compliance obligation of about [redacted] for the Cap-and-Trade Second Compliance period (2015, 2016, and 2017).[266] Based on ARB regulations, PG&E can meet up to 8% of its compliance obligation for the Second Compliance Period using offsets, which is about [redacted] PG&E procured about [redacted] [redacted] in offsets that could be used to meet its compliance obligation for the Second Compliance period.

During the 2015 Record Period, PG&E procured [redacted][267] PG&E procured offsets from four counterparties: about [redacted] or [redacted] of the total offsets were procured from [redacted] about [redacted] of total offsets were from [redacted] about [redacted] or [redacted] were from [redacted] and about [redacted] or [redacted] from [redacted] [redacted].[268]

Given that the price of offsets was [redacted] than the price of allowances obtained in auctions in 2015, ORA was interested in understanding PG&E's strategy for procuring offsets to meet its compliance obligations for Cap-and-Trade Second Compliance period.

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[265] *Id.*

[266] PG&E Advice Letter 4507-E [CONFIDENTIAL], Appendix L, p. 303.

[267] PG&E Advice Letter 4783-E [Procurement Transaction Quarterly Compliance Filing (Q4, 2015). Source: PG&E Workpapers submitted with this Application.

[268] *Id.*

Table 7-5 in Chapter 7 of PG&E’s Testimony, indicates that PG&E procured [redacted] from [redacted], and [redacted] from [redacted]. Additionally, in Chapter 7 of its Testimony, PG&E noted that” [redacted].”[269] However, PG&E’s testimony did not explain how it established its targets or its or its strategy for procuring of offsets.

Given that PG&E’s reported offsets in Chapter 7 of its Testimony did not match the reported offsets in its Fourth Quarter of 2015 Quarterly Compliance Report, ORA issued data requests to determine PG&E’s strategy for procuring offsets.[270] In its response, PG&E referred ORA to presentation materials from the Procurement Review Group (PRG) and did not directly respond to ORA’s questions.[271] PG&E included multiple objections to ORA questions regarding offset procurement strategy for the 2016 and 2017 compliance periods, stating that such requests are out of scope of the 2015 ERRA Compliance proceeding. Furthermore, PG&E stated that it [redacted].[272] As a result, ORA held Meet & Confer meetings clarifying the relevance of questions to this proceeding.[273] Based on PG&E responses following the meeting, PG&E’s did not answer the requested questions and instead provided details regarding RFOs that it held during the [redacted]. PG&E stated that “[redacted].”[274] [275]

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[269] Table 7-5 in Chapter 7 of PG&E Testimony.

[270] ORA Data Request 15 Question 2, issued April 21, 2016.

[271] PG&E Response to ORA DR 15 Question 2, received May 5, 2016.

[272] *Id.*

[273] Meet & Confer Meeting, May 16, 2016.

[274] PG&E Response to ORA Data Request Number 15 Question 3, received May 5, 2016. In its response to ORA Data Request, PG&E objected to providing the full information requested in a spreadsheet template that ORA provided in its initial Data Request. In its, supplemental response, received on May 27, 2015 (After a Meet and Confer Meeting with ORA) PG&E filled in the requested information but did not provide explanation to the entries in the spreadsheet, as such ORA was not able to use the data provided. See Exhibit 4.

[275] PG&E Response to ORA DR 15 Question 2, received May 24, 2016. PG&E filled in a spreadsheet template that ORA provided in its DR, however, PG&E did not provide explanation to the entries in the spreadsheet, as such ORA was not able to use the data provided.

As such, ORA was not able to determine whether PG&E pursued cost-effective options to procure compliance instruments that could have resulted in lower costs to ratepayers.

ii) PG&E did not Substantiate its Calculation of the Costs Associated with Procurement of Compliance Instruments

D.10-14-033 (as corrected by D.15-01-024) requires a utility to calculate the Direct GHG costs as the sum of each month's WAC of its compliance instruments inventory multiplied by that month's actual Direct emissions for which the utility has a physical compliance obligation.[276] The WAC is based on a utility's inventory of all allowances and offsets, eligible to meet the compliance obligation for the current compliance period under the Cap-and-Trade program. For instance, when calculating the WAC for 2015, a utility shall calculate its WAC based on its inventory of allowances with vintage years 2015, 2016, and 2017, plus any 2013 and 2014 allowances that were not used to meet its obligation in the first compliance period. ARB does not restrict the vintage year for offsets that a utility can use to meet its compliance obligation.

ORA asked PG&E to clarify the costs included in Chapter 7 of its Testimony, specifically whether these costs were for the purpose of cost recovery, and how they relate to the costs presented in the GHG ERRA subaccount in Chapter 12.[277] PG&E stated that,

> "the GHG compliance instrument procurement discussed in Chapter 7 does not include a cost recovery request. PG&E is requesting a finding from the Commission regarding GHG compliance instrument procurement and is limited to PG&E having complied with the 2010 and 2014 Commission-approved BPP. This is consistent with the Commission's review in previous ERRA Compliance proceedings. See e.g. Scoping Memo and Ruling of Assigned Commissioner, issued June 26, 2015 at p. 4 in Application 15-02-023 (identifying issue regarding GHG as "[d]id PG&E's Greenhouse Gas Compliance Instrument Procurement comply with its Bundled Procurement Plan?")".[278]

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[276] Decision 15-01-024 Attachment C.

[277] ORA Data Request No. 15 Question 1, issued on April 21, 2016.

[278] PG&E Response to ORA Data Request No. 15 Question 1, received on May 23, 2016.

Despite multiple data requests, PG&E did not provide the calculation of the WAC that was used to calculate the Direct GHG costs that was used in the GHG ERRA subaccount (Tariff Line item 5.ah).[279] During a Meet & Confer meeting ORA clarified to PG&E the relevance of its request.[280] Following the meeting, PG&E provided ORA with a spreadsheet containing entries for the WAC.[281] However, the spreadsheet did not include calculations (or explanations of the terms used in the spreadsheet).

ORA was not able to verify the accuracy of PG&E's WAC calculations, and whether the calculations met the requirements set in Commission's Decisions. Accordingly, ORA was not able to determine if the entries in the ERRA GHG subaccount (tariff line 5.ah) were reasonable or accurate. Therefore, ORA recommends the Commission to disallow PG&E's claim for cost recovery for [redacted], which is recorded under its ERRA GHG subaccount (tariff line 5.ah).

V. CONCLUSION

ORA recommends that the Commission:

- Disallow a cost recovery of [redacted] in PG&E's ERRA Greenhouse Gas (GHG) subaccount (ERRA Tariff Line Item 5.ah) because PG&E did not provide the calculations of its Direct GHG emissions from energy procured from PG&E's owned-facilities, tolling agreements, qualifying facility contracts, and imports. PG&E did not provide sufficient details on how it derived its average weighted costs used in the calculation of Direct GHG costs.
- Disallow a cost recovery of [redacted] in estimated Indirect GHG costs embedded in energy purchases from contracts ([redacted] of which are associated with contract purchases with no specific provision for settlement of GHG costs, and [redacted] of which are associated with contract purchases with financial settlement with specific GHG costs provisions). PG&E did not provide the calculations of the estimated GHG emissions from energy procured from these contracts. PG&E did not provide a sufficient explanation to substantiate the calculations of Indirect GHG costs related to

[279] Ibid. PG&E stated that "The Weighted Average Cost of Compliance Instruments calculations is documented in the Monthly ERRA Activity Reports, which are included in PG&E's confidential workpapers for Chapter 12." ORA did not find the calculations of the WAC in PG&E's workpapers for Chapter 12.

[280] Meet & Confer Meeting held on May 16, 2016.

[281] PG&E Response to ORA Data Request No. 9, issued on March 28, 2016; received on May 31, 2016.

these contracts, and how these costs correlate to the costs reported under PG&E's three ERRA accounts (Tariff Lines 5.ae, 5.n, and 5.o).

- PG&E should provide the Commission with verifiable information, specifically:
  - Calculations of Direct GHG emissions from its procured energy;
  - Calculations of Indirect GHG emissions from its procured energy from market and contract purchases;
  - Methodologies used to calculate Direct and Indirect GHG costs in sufficient details, including verifiable references; and
  - Supportive data to show how PG&E operated and managed its GHG program prudently in a least-cost manner.

While ORA recommends to the Commission the stated disallowances, ORA expects that PG&E incurred some of these Direct and Indirect GHG costs. However, without sufficient information to verify that PG&E has applied the required methodologies, ORA cannot attest to the reasonableness of the methodologies that PG&E applied to produce its recorded Direct GHG emissions and associated costs, as well as its estimates of some of its Indirect GHG emissions and associated costs. As such, ORA could not determine if PG&E's methodologies were consistent with Commission and state polices and law, and whether the incurred costs were recorded accurately, let alone reasonable.

List of Exhibits

Exhibit 1: Confidential PG&E Response to ORA Data Request Number 15, Question 1 including spreadsheet titled "ERRA-2015-PGE-Compliance_DR_ORA_015-Q01Atch02-CONF" [CONFIDENTIAL]

Exhibit 2: Confidential PG&E Response to ORA Data Request Number 15, Question 2, including supplemental responses [CONFIDENTIAL]

Exhibit 3: Confidential PG&E Response to ORA Data Request Number 20, Question 12 [CONFIDENTIAL]

Exhibit 4: Confidential PG&E Response to ORA Data Request Number 15, Question 3, including supplemental response and spreadsheet titled "ORA_DR_15_Q2_c_2015_Offsets_Confidential" [CONFIDENTIAL]

CHAPTER 8 CONTRACT ADMINISTRATION

(Witness: Mea Halperin)

I. INTRODUCTION AND SUMMARY

This chapter of testimony presents ORA's review of PG&E's contract administration processes and activities for the Record Period from January 1, 2015 through December 31, 2015. ORA's review focuses on the contract amendments and settlements that resulted in an increase to the notional value of the Power Purchase Agreements (PPAs). The notional value changes were not approved during the Record Period, or in separate applications, or advice letters and PG&E is seeking the Commission's approval in this Application.

II. RECOMMENDATIONS

ORA reviewed five contracts with amendments resulting in a notional value increase for which PG&E is requesting Commission approval, as well as three contracts with overpayments. ORA conducted this review by analyzing testimony, issuing data requests, meeting with PG&E to discuss individual contracts, and reviewing past testimony for precedents. Based on the information provided to ORA and under the standards of review described below in section IV.b., ORA does not object to PG&E seeking approval of all five contract amendments, but recommends a [redacted].

III. BACKGROUND

The Commission has established minimum standards of conduct, including Standard of Conduct 4 (SOC4) for contract administration, stating that the utilities "shall prudently administer all contracts and generation resources and dispatch energy[282] in a least-cost manner."[283] This ensures that the utilities have "operated [their] resources to produce the lowest possible cost for customers."[284] Prudent contract administration also entails "administration of all contracts within the terms and conditions of those contracts, to include

[282] This responsibility was further clarified in D.14-05-023, Finding of Fact 15, stating that while the regulated utilities are responsible for bidding and scheduling its generation resources in a least-cost manner, it is the California Independent System Operator (CAISO) who performs actual generation dispatch. (D.14-05-023, p. 19.)

[283] D.02-10-062, p. 74.

[284] D.05-01-054, p. 14.

dispatching dispatchable contracts when it is most economical to do so."[285] In addition, it is the utility's responsibility to "dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs."[286]

The Commission also established that the utility bears the burden of proving that it has administered its contracts reasonably and in compliance with the Standards of Conduct to produce the lowest possible costs for ratepayers.[287] In prior ERRA proceedings, PG&E acknowledged this burden of proof and that the utility must demonstrate its compliance through its testimony.[288]

IV. DISCUSSION AND ANALYSIS

A. Discussion

For the 2015 Record Period, ORA reviewed five contract amendments that resulted in an increase to the notional value of the underlying PPA and were "not separately approved through another Commission mechanism or process."[289] Additionally, ORA reviewed three contracts that resulted in overpayments. ORA's review is limited to the following eight contracts for which PG&E is seeking approval, as detailed in Chapter 8, Section J of PG&E's prepared testimony[290] and in PG&E's supplemental testimony for Chapter 8:[291]

i.) Midway Sunset Cogeneration Company (PG&E Log No. 33B126)

The Midway Sunset Cogeneration facility is a natural gas-fired cogeneration plant located in Fellows, CA in the Kern local area. The amendment, executed on April 24, 2015, would allow Midway Sunset to attain the California Independent System Operator's (CAISO) Certification of Regulation three months later than the initial delivery date. During these three months (June 1 – August 31, 2015), PG&E would pay the facility a dispatch capacity payment of [redacted], as agreed upon in

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[285] D.02-12-074, p. 54.

[286] *Id*.

[287] *Id.*

[288] Proposed Decision, PG&E 2012 ERRA Compliance, A.13-02-023, Standards of Review, p. 11.

[289] A.16-02-019, Testimony, Chapter 8, Section J, p. 8-40.

[290] *Id*, p. 8-40 through 8-42.

[291] A.16-02-019, Supplemental Testimony, Chapter 8, p. 8-3 through 8-4.

the underlying PPA. [redacted].

ii.) Madera Chowchilla Water and Power Authority (PG&E Log No. 25H036)

The Madera Chowchilla Qualifying Facility (QF) is located in Madera, CA. This amendment, executed on January 30, 2015, extends the contract for two months at an estimated notional value of [redacted]. The purpose of the extension was to keep the facility operational while it transitioned into a Renewable Market Adjusting Tariff (ReMAT) contract.

iii.) Green Ridge Power, LLC (PG&E Log No. 01W035)

Green Ridge Power owns wind turbines in Altamont, CA. This contract amendment, executed on February 20, 2015, extends a legacy QF agreement for nine months at a value of $1.9 million as part of a deal with PG&E to shorten the term of three other Green Ridge Power PPAs, all four of which were being paid above-market energy and capacity prices.[292] The extended contract (identified going forward as 01W035) was slated to terminate on March 31, 2015, and instead terminated on December 31, 2015. The other three contracts were also shortened by one year terminating on the same date, December 31, 2015.[293]

All four PPAs were receiving energy payments of [redacted] under Fixed Energy Price Amendments executed in the Qualifying Facility and Combined Heat and Power (QF/CHP) Settlement,[294] and as-available capacity payments of [redacted] according to the original PPAs.[295] Under this amendment, energy produced by 01W035 during the nine-month extension period would be paid at the Short Run Avoided Cost (SRAC).[296] The avoided cost of terminating the three PPAs early was [redacted], [redacted]. PG&E's net present value calculation determines a [redacted]. The impact to PG&E's Renewable Portfolio

[292] A.16-02-019, Testimony, Chapter 8, Section J, Part 3, p. 8-41.

[293] A.16-02-019, Chapter 8 Workpapers, Agreements Listed in Chapter 8_Section J, "Expiration Date Amendment to Standard Offer #4 Power Purchase Agreement Log Number 01W035," p. 1-2.

[294] Approved by the Commission in decision D.10-12-035.

[295] PG&E Response to Data Request 16, Question 9, Part a, Footnote 1.

[296] A.16-02-019, Chapter 8, Section J, Part 3, p.8-41.

Standard (RPS) compliance is [redacted]

iv.) Geysers Power Company (PG&E Log No. 33T002)

The Geysers Power Company owns a 21 kilovolt (kV) transmission line that provides geothermal energy to thirteen customers in Lake County, CA. PG&E and Geysers executed an amendment to their evergreen Retained Assets Agreement[298] on June 3, 2015 that defines pricing for the next ten years, reimbursing Geysers for electric service to PG&E customers and substations along this 21 kV transmission line. Under this amendment, PG&E will pay Geysers [redacted][299]

v.) Enerparc CA1, LLC (PG&E Log No. 33R210AB)

Enerparc and PG&E entered into a feed-in tariff (FIT) PPA on September 26, 2011, wherein PG&E contracted solar power. This original PPA had a discrepancy between the contract capacity amount in the project description, which was 1.499 megawatts (MW), and the single line diagram in the contract's appendix, showing a capacity of 1.5 MW. This contract amendment, executed on August 27, 2015, corrects the contract capacity to 1.5 MW to match the text of the agreement with the appendix. The notional value increase is approximately [redacted]

When the facility began commercial operation on June 16, 2014, PG&E was paying Enerparc for 1.499 MW per settlement interval, while the facility regularly generated 1.5 MW. Enerparc caught the discrepancy between the facility's generation and the capacity being paid for. PG&E agreed to reimburse Enerparc for the unpaid portion of energy generated between June 16, 2014 and September 1, 2015, which was [redacted]. Beginning

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[297] PG&E Response to Data Request 02, Question 12.

[298] A Retained Assets Agreement is a legacy agreement dating back to when the utilities divested many of their assets during the restructuring of California's electricity market under Assembly Bill 1890. In the context of the contract amendment with Geysers Power Company (Log No. 33T002), Geysers and Calpine own the energy generating facility and the transmission/distribution lines, but PG&E still owns the cables leading from distribution to the customers (Retained Connections) and equipment necessary for the proper interconnection and operation of the energy generating facility with the PG&E system (Special Facilities, itemized in Appendix A), collectively the retained assets. The agreement maintains cooperation between the parties to allow PG&E to meet its requirements to serve all customers within its service territory. (PG&E Response to Data Request 23, Question 4.)

[299] A.16-02-019, Chapter 8 Workpapers, Agreements Listed in Chapter 8_Section J, "Fourth Amendment to the Retained Assets Agreements Between Geysers Power Company, LLC and Pacific Gas and Electric Company Dated May 6, 1999 (Sonoma County Facility and Lake County Facility, The Geysers)." p. 4.

on September 1, 2015 PG&E would pay Enerparc for energy delivered up to 1.5 MW per settlement interval.[300]

vi.) Global Ampersand, LLC – El Nido Biomass Facility (PG&E Log No. 33R016) and Global Ampersand, LLC – Chowchilla Biomass Facility (PG&E Log No. 33R017)

Global Ampersand, LLC owns two biomass facilities – El Nido and Chowchilla – each facility has a contract capacity of 9 MW. PG&E and Global Ampersand entered into PPAs in 2005, and in February of 2011 executed amendments to each contract changing the performance penalty calculation. This calculation provides a quantitative metric for determining the capacity factor, or the ratio between the generator's delivered energy and its contract capacity. If the calculated capacity factor is less than the performance requirement as defined in the PPAs, the facility incurs a penalty.[301]

In March of 2015, PG&E discovered two errors in its performance penalty calculation: [redacted] PG&E used this incorrect calculation from February 2012 to May 2015. Due to stipulations in the PPAs[302] PG&E was unable to recover from Global Ampersand any of the El Nido overpayment amount. [redacted] The resulting net overpayments amount to [redacted].

vii.) Starwood Midway (PG&E Log No. 33B074)

The Starwood Midway natural gas-fired facility is contracted for 118.06 MW of generation. PG&E and Starwood Midway entered into a PPA on April 3, 2006. The contract

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[300] PG&E Response to Data Request 02, Question 20.

[301] A.16-02-019, Supplemental Testimony, Chapter 8, Section C, p. 8-3.

[302] "If an invoice is not rendered within twelve (12) months after the close of the month during which performance of under the Transaction occurred, the right to payment for such performance is waived." (PG&E Response to Data Request 16, Question 11, Part e.)

[303] PG&E Response to Data Request 23, Question 1, Part a.

[304] ORA Testimony, Chapter 8, Contract Administration Workpapers, "04_Global & Costs."

includes the application of a "unique factor,"[305] the Gross Domestic Product (GDP) Implicit Price Deflator,[306] for escalating its start-up, variable operations and maintenance (O&M), and fixed O&M payment rates.

In May 2014, PG&E reviewed the payment rates and found that it had incorrectly applied[307] the GDP growth rate to the calculation instead of the GDP Implicit Price Deflator, contrary to the defined terms in the original PPA. PG&E used this incorrect calculation from May 2010 through May 2014, resulting in a total overpayment of [redacted] Due to stipulations in the PPA[309] [redacted]

B. Analysis

ORA used the following standards of review to evaluate PG&E's activities regarding its administration of contract amendments that resulted in an increase to the notional value:

i.) What are the actual and/or notional values of the contract amendments?

ii.) How are the actual and/or notional values accounted for in the utility's expense and/or revenue accounts?

iii.) Did the utility adequately justify or explain the rationale for the contract amendments, either in the application, testimony, MDR, or data requests?

iv.) Were the amendments motivated by operational needs, such as obtaining more cost-effective resources, lower market prices, or by developer's request?

v.) Do the amendments reflect the ratepayers' and/or stakeholders' best interests?

ORA reviewed PG&E's testimony and supplemental testimony, Master Data Request responses, supplemental data request responses, workpapers, past ERRA testimony, and prior

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[305] A.16-02-019, Supplemental Testimony, Chapter 8, Section D, p. 8-4.

[306] PG&E Response to Data Request 23, Question 3, Part c.

[307] PG&E Response to Data Request 16, Question 11, Part a.

[308] PG&E Response to Data Request 23, Question 3, Part f.

[309] A.16-02-019, Supplemental Testimony, Chapter 8, Section D, p. 8-4.

[310] *Id.*

[311] Email from Leslie Almond, PG&E ERRA Coordinator, June 30, 2016.

Commission decisions. ORA also met with representatives PG&E's Contract Management and Settlements group on March 17, 2016 to discuss PG&E's broader contract administration processes. Additionally, ORA and PG&E had two telephone conversations on March 24, 2016 and April 13, 2016 to discuss specific details pertaining to administering specific contracts and understanding contract types.

Based on these communications and review of PG&E's testimony, ORA provides the following analysis:

i.) Midway Sunset Cogeneration Company

Based on actual dispatch data submitted in PG&E's bid sheets as part of the utility's least-cost dispatch showing, between June 1, 2015 and August 31, 2015 the Midway Sunset facility was dispatched for [redacted]. The sum of PG&E's dispatch capacity payment at the lower rate [redacted]s [redacted]

Without the agreed upon amendment, it would not have been possible for the facility to generate energy until it had received CAISO certification of regulation.[313] The amendment allowed the facility to begin generation in time to provide electricity during the high demand summer months. Given that the facility is among PG&E's larger thermal resources[314] and has no daily or annual start up limitations[315] ORA finds that this amendment is reasonable and within the best interest of PG&E's bundled customers.

ii.) Madera Chowchilla Water and Power Authority

The [redacted] notional value increase is based on an estimate of the payments PG&E would make to Madera Chowchilla for any actual generation from the facility during the two-month extension period. During these two months, [redacted]

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[312] ORA Testimony, Chapter 8, Contract Administration Workpapers, "01_Midway Sunset Costs."

[313] PG&E Response to Data Request 16, Question 7, Part a.

[314] PG&E Response to Data Request 22, Question 4.

[315] Email from Leslie Almond, PG&E ERRA Coordinator, June 23, 2016.

[316] PG&E Response to Data Request 08, Question 11.

[redacted] The decision to extend the PPA was prudent [redacted].

iii.) Green Ridge Power, LLC

Although the least costly option for administering these four contracts would be to simply terminate the three PPAs early without extending 01W035, PG&E could not unilaterally terminate the contracts early without Green Ridge suing for damages.[318] [redacted] ORA is satisfied that PG&E negotiated the most beneficial outcome in terms of overall cost to ratepayers, energy reliability, and RPS compliance.

iv.) Geysers Power Company

The overall notional value increase, based on the reported average annual [redacted] h) of delivered load to the customers along this transmission line, is $243,660 for all ten years.[320] The stated purpose of the pricing plan is to "eliminate the need to build infrastructure,"[321] and to prevent future pricing disputes.[322] However, additional discovery revealed that [redacted], but rather "to determine a price for the distribution-level RPS energy delivered directly to PG&E retail bundled-load customers under the existing contract."[323] Additionally, [redacted]

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[317] PG&E Response to Data Request 16, Question 8, Part b.

[318] PG&E Response to Data Request 16, Question 9, Part d-e.

[319] PG&E Response to Data Request 16, Question 9, Part a.

[320] **ORA Testimony, Chapter 8, Contract Administration Workpapers, "02_Geysers Costs."**

[321] A.16-02-019, Testimony, Chapter 8, Section J, Part 4, p. 8-41.

[322] PG&E Response to Data Request 02, Question 17.

[323] PG&E Response to Data Request 08, Question 13, Part c.

[324] *Id.*, Part d.

PG&E's explanation for the discrepancy is that [redacted] While ORA determined that the given justification was incomplete, the pricing plan is consistent with past agreements between PG&E and Geysers and is a reasonable plan that enables PG&E and Geysers to continue providing electricity services to local customers.

While this amendment is a result of an error on PG&E's part, the notional value increase of [redacted] is de minimis and therefore not a significant concern.

v.) Global Ampersand, LLC, El Nido and Chowchilla Biomass Facilities

Given that the overpayments were a result of a calculation error on the part of PG&E, ORA determines that it is not the responsibility of the ratepayers to bear the costs. ORA recommends [redacted]

vi.) Starwood Midway

Similarly, this overpayment was a result of a calculation error on the part of PG&E and ORA determines that it is not the responsibility of the ratepayers to bear the costs. [redacted]

V. CONCLUSION

Based on the analysis and evaluations delineated above, ORA has no objections to PG&E's request for approval of contract amendments resulting in an increase in the notional value of the underlying PPAs. However, ORA recommends [redacted]

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325 PG&E Response to Data Request 16, Question 10, Part e.

326 ORA Testimony, Chapter 8, Contract Administration Workpapers, "04_Global & Costs."

327 A.16-02-019, Supplemental Testimony, Chapter 8, Section D, Footnote 4, p. 8-4.

328 ORA Testimony, Chapter 8, Contract Administration Workpapers, "05_Total Overpayments."

LIST OF ATTACHMENTS FOR CHAPTER 8

#	ATTACHMENT	DESCRIPTION
1	Attachment 8.1	PG&E Response to Data Request 16, Question 9.
2	Attachment 8.2	PG&E Response to Data Request 02, Question 12.
3	Attachment 8.3	PG&E Response to Data Request 23, Question 4.
4	Attachment 8.4	PG&E Response to Data Request 02, Question 20.
5	Attachment 8.5	PG&E Response to Data Request 16, Question 11.
6	Attachment 8.6	PG&E Response to Data Request 23, Question 1.
7	Attachment 8.7	ORA Testimony, Chapter 8, Contract Administration Workpapers, "04_Global & Costs."
8	Attachment 8.8	PG&E Response to Data Request 23, Question 3.
9	Attachment 8.9	Email from Leslie Almond, PG&E ERRA Coordinator, June 30, 2016.
10	Attachment 8.10	ORA Testimony, Chapter 8, Contract Administration Workpapers, "01_Midway Sunset Costs."
11	Attachment 8.11	PG&E Response to Data Request 16, Question 7.
12	Attachment 8.12	PG&E Response to Data Request 22, Question 4.
13	Attachment 8.13	Email from Leslie Almond, PG&E ERRA Coordinator, June 23, 2016.
14	Attachment 8.14	PG&E Response to Data Request 08, Question 11.
15	Attachment 8.15	PG&E Response to Data Request 16, Question 8.
16	Attachment 8.16	ORA Testimony, Chapter 8, Contract Administration Workpapers, "02_Geysers Costs."
17	Attachment 8.17	PG&E Response to Data Request 02, Question 17.
18	Attachment 8.18	PG&E Response to Data Request 08, Question 13.
19	Attachment 8.19	PG&E Response to Data Request 16, Question 10.
20	Attachment 8.20	ORA Testimony, Chapter 8, Contract Administration Workpapers, "05_Total Overpayments."

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Data Response

PG&E Data Request	ORA_016-Q09		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_016-Q09		
Request Date:	May 2, 2016	Requester DR No.:	016
Date Sent:	May 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 9

Green Ridge Power, LLC (PG&E Log No. 01W035)

a.Did PG&E consider any other options for the early termination of the other 3 Green Ridge PPAs (Log Nos. 01W018, 16W011, and 01W146D)?

b.Who initiated the deal to extend the one PPA in exchange for the early termination of the other 3 PPAs?

c.After this contract amendment, extending the one PPA and terminating the other 3 PPAs, does PG&E still have ongoing PPAs, other agreements, or contracts with Green Ridge Power, LLC?

d.Did PG&E conduct a cost/benefit analysis with regard to this amendment? For example, did PG&E evaluate the financial risk or weigh the relative cost of the least expensive solution (e.g. simply terminating the 3 PPAs early without extending the one PPA) against the potential loss of future business, litigation costs, or any other transactional costs involved in contract negotiations?

e.Was there a penalty in the 3 Green Ridge PPAs for early termination that would have cost more than [redacted]

ANSWER 9

PG&E responds as follows:

a.With regard to alternative options considered in exchange for early termination of the three power purchase agreements ("PPAs") (Log Nos. 01W018, 16W011, and 01W146D), [redacted]

[redacted]

b.Green Ridge initiated the proposal to extend one PPA in exchange for early termination of the other three PPAs.

c.No. As of January 1, 2016, PG&E does not have any ongoing PPAs with Green Ridge Power, LLC.

d.Yes. As described in PG&E's response to ORA Data Request Set #2, Question #10 (ORA_002-Q10), PG&E compared the cost of the status quo against the benefit of the amendments to all four of the Green Ridge PPAs. PG&E calculated the Net Market Value of the existing contracts where the present value of the contract payment stream (cost) was compared with the present value of the contract's market value to determine the benefit (positive or negative) of signing the amendments. PG&E calculated a positive Net Market Value for each of the three early expirations because they provided positive benefit by ending the existing above-market contract payments. PG&E also calculated a positive Net Market Value for the extension of 01W035 since energy payments to Green Ridge priced at PG&E's Short Run Avoided Cost was estimated to be less than procuring from market resources. In other words, during the period that Green Ridge 01W035 was extended, PG&E would have spent more to procure energy from the market than purchasing energy under the extended contract. PG&E also received added benefit of receiving RPS- eligible generation at no additional premium during the 01W035 extension period. The "least expensive solution" cited as an example in this question was not available to PG&E because PG&E could not unilaterally terminate Green Ridge's PPAs.

e.[redacted] However, these Standard Offer form contracts were adopted by the CPUC as part of its implementation of the Public Utility Regulatory Policies Act of 1978, under which investor-owned utilities such as PG&E must purchase the power delivered by qualifying facilities (QFs) such as Green Ridge's predecessor at avoided cost. If PG&E had tried to terminate the contracts early, Green Ridge may have initiated regulatory or civil litigation to seek damages.

[1] Each of four projects (Log Nos. 01W018, 16W011, 01W146D, and 01W035) were under Fixed Energy Price Amendments executed under the Qualifying Facility and Combined Heat and Power ("QF/CHP") Settlement approved by the Commission in Decision ("D.") 10-12-035, where Green Ridge received payments for energy starting in February 2012 at $53.70 per MWh (non- Time of Use adjusted) for up to 5 years or the remaining term of the contract. As payment for as-available capacity, each of the 4 projects received $188.00 per kW-yr according to the Standard Offer #4 contracts.

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PG&E Data Request	ORA_002-Q12		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_002-Q12		
Request Date:	March 4, 2016	Requester DR No.:	002
Date Sent:	March 18, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Mea Halperin

QUESTION 12

What is the impact of this deal upon PG&E's RPS compliance?

ANSWER 12

At the time PG&E entered into the transactions, PG&E estimated the extended contract (PG&E Log No. 01W035) would result in an incremental 66,243 MWh of RPS-eligible generation. In comparison, PG&E estimated that shortening the other three contracts (PG&E Log. No. 01W018, 16W011, and 01W146D) would amount to 85,369 MWh less of RPS-eligible generation for the shortened duration of three wind projects. On an overall net basis, the four transactions amounted to an estimated decrease in RPS- eligible generation by 19,125 MWh. PG&E determined this amount would not have a material impact on PG&E's RPS compliance position.

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PG&E Data Request	ORA_023-Q04		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_023-Q04		
Request Date:	June 10, 2016	Requester DR No.:	023
Date Sent:	June 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 4

In the April 13, 2016 phone conversation that ORA had with Ted Yura, PG&E Senior Manager for Contract Administration and Settlements, a Retained Assets Agreement was defined as a legacy agreement dating back to when the utilities divested from many of their assets after the California energy crisis. In the context of the contract amendment with Geysers Power Company (Log No. 33T002), Geysers and Calpine own the energy generating facility and the transmission/distribution lines but PG&E still owns the cables leading from distribution to the customers (the retained assets in question). The agreement maintains cooperation between the parties to allow PG&E to meet its requirements to serve all customers within its service territory.

a. Is this an accurate summary of the definition of a Retained Assets Agreement?
b. If not, please provide any additions or modifications to the definition.

ANSWER 4

In the April 13, 2016 phone conversation that ORA had with Ted Yura, PG&E Senior Manager for Contract Administration and Settlements, a Retained Assets Agreement was defined as a legacy agreement dating back to when the utilities divested from many of their assets ~~after the California energy crisis~~ during the restructuring of California's electric generation market, under AB 1890. In the context of the contract amendment with Geysers Power Company (Log No. 33T002), Geysers and Calpine own the energy generating facility and the transmission/distribution lines but PG&E still owns the cables leading from distribution to the customers (*Retained Connections*), and equipment necessary for the proper interconnection and operation of the energy generating facility with the PG&E system (*Special Facilities*, itemized in Appendix A), collectively the retained assets(~~the retained assets in question)~~. The agreement maintains cooperation between the parties to allow PG&E to meet its requirements to serve all customers within its service territory.

a. Yes, with the provided edits, this is an accurate summary of the agreement.

b. Strikethrough represents deletions and underlining additions.

CONFIDENTIAL INFORMATION Protectable under General Order 66-C, and Submitted under P.U.C. §§ 454.5(g) and 583

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Data Response

PG&E Data Request	ORA_002-Q20		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_002-Q20-CONF		
Request Date:	March 4, 2016	Requester DR No.:	002
Date Sent:	March 18, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Mea Halperin

QUESTION 20

Between the online date (6/16/14) and the PPA amendment (9/11/15), how much energy was Enerparc producing versus what was being paid for?

ANSWER 20

This data response contains Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted]

[redacted]

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Data Response

PG&E Data Request	ORA_016-Q11		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_016-Q11		
Request Date:	May 2, 2016	Requester DR No.:	016
Date Sent:	May 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 11

Global Ampersand, LLC – El Nido Biomass Facility (PG&E Log No. 33R016) and Chowchilla Biomass Facility (PG&E Log No. 33R017)

a. Please send a copy of each of the PPA amendments for El Nido Biomass and Chowchilla Biomass executed on February 8, 2011.

b. What is the basis for Global Ampersand's dispute against PG&E's right to adjust invoices for the February 2014 – May 2015 delivery periods?

c. What is the total dollar amount that PG&E overpaid to each Global Ampersand PPA?

d. What is the dollar amount of the overpayment that PG&E was able to recover from each PPA?

e. [redacted]

f. If PG&E is not able to recover the overpayment amounts in question (e.) from Global Ampersand, from where will these amounts be recovered?

ANSWER 11

PG&E responds as follows:

a. Attachments 1 and 2 to this data response contain the amendments for Chowchilla (see PDF document, "ERRA-2015-PGE- Compliance_DR_ORA_016-Q11Atch01.pdf") and El Nido (see PDF document, "ERRA-2015-PGE-Compliance_DR_ORA_016-Q11Atch02.pdf").

b. Global Ampersand and PG&E disagree on the interpretation of the timeline for disputing invoices for Performance Penalties under the PPA. Global Ampersand believes that invoices for Performance Penalties must be submitted within 60 days after the applicable Period. PG&E believes that it has the right to invoice up to 12 months after the end of any Period.

c. [redacted]

f. PG&E has already booked the amount of all invoices, including the overpayment, into its Energy Resource Recovery Account.

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PG&E Data Request	ORA_023-Q01		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_023-Q01-CONF		
Request Date:	June 10, 2016	Requester DR No.:	023
Date Sent:	June 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 1

[redacted]

[redacted]

[redacted]

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

ANSWER 1

This question, data response and attachment contain Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted].

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

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PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
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Data Response

PG&E Data Request	ORA_023-Q03		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_023-Q03-CONF		
Request Date:	June 10, 2016	Requester DR No.:	023
Date Sent:	June 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 3

Starwood Midway (PG&E Log No. 33B074)

a. In what year was the original PPA between PG&E and Starwood Midway executed?
b. Was the payment rate calculation changed at any time during the life of the PPA?
c. What is the "unique factor" for escalating the start-up, variable O&M, and fixed O&M payment rates?
d. How was this unique factor decided upon?
e. Why was a less-unique factor not chosen for the payment rate escalator?
f. What is the total dollar amount that PG&E overpaid to Starwood Midway?
g. Please provide some examples of the options presented in the negotiations for modifying the contract, providing benefits to Starwood Midway, and lowering customer costs.

ANSWER 3

This data response contains Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted]

[redacted]

[redacted].

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

Halperin, Mea

From: lea6@pge.com <ftpadmin@cpuc.ca.gov>
Sent: Thursday, June 30, 2016 1:46 PM
To: Halperin, Mea
Subject: Response to Midway Sunset Overpayment Calculation question

Mea,

Please see PG&E's response to your questions discussed on Tuesday's phone call concerning the overpayments for Starwood
Midway. Thank you.

- Leslie

CONFIDENTIAL INFORMATION
Protectable under D.06-06-066,
Appendix I,
and Submitted under Pub. Util. Code §§ 454.5(g) and 583

[redacted]

Leslie Almond
Expert Case Manager
PG&E

Secured by Accellion

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]		[redacted]				[redacted]	
[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]		[redacted]		[redacted]		[redacted]	

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Contract Administration Testimony Workpapers01_Midway Sunset Costs

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account 2015 Compliance Review
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Data Response

PG&E Data Request	ORA_016-Q07		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_016-Q07-CONF		
Request Date:	May 2, 2016	Requester DR No.:	016
Date Sent:	May 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

SUBJECT: CHAPTER 8 – CONTRACT ADMINISTRATION

QUESTION 7

Midway Sunset Cogeneration Company (PG&E Log No. 33B126):

a. [redacted]

[redacted]

[redacted]

[redacted]

e. What is the estimated notional value increase from this PPA amendment?

ANSWER 7

This data response contains Confidential Information pursuant to General Order 66-C and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
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Data Response

PG&E Data Request	ORA_022-Q04		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_022-Q04		
Request Date:	June 7, 2016	Requester DR No.:	022
Date Sent:	June 13, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Alva Svoboda	Requester:	Mea Halperin

LEAST COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE (CHAPTER 1)

QUESTION 4

Please provide a list of all of PG&E's energy resources (including UOG, partially owned, and contracted), and provide the resource ID, generator name, local area (or CAISO system), whether it is north or south of Path 26, Pmax, Pmin, whether they are dispatchable or non-dispatchable, type of energy (hydro, combined cycle, peaker, solar, etc.), and net qualifying capacity per month of 2015. Please see the attached blank spreadsheet for a sample format.

ANSWER 4

The attachments to this data response contain Confidential Information pursuant to Decision 06-06-066, Appendix I, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

Response to this data request is provided in the spreadsheet provided by ORA (see attachment). One item of note for column C, local area, PG&E does not perform least cost dispatch based on local area. Instead, generation is provided to the CAISO and production is based on the CAISO's market and operational needs.

Halperin, Mea

From:	Almond, Leslie
<LEA6@pge.com> **Sent:**	Thursday, June 23, 2016
7:37 AM **To:**	Halperin, Mea
Cc:	Lasko, Yakov; Almond, Leslie
Subject:	RE: Update to Scheduling Protocol for Midway Sunset
Attachments:	ERRA-2015-PGE-Compliance_DR_ORA_008-Q08Atch01-CONF - KAJH

edit.xlsx

Mea,

There have not been any updates to the Scheduling Protocol for Midway Sunset, but the Contract Manager did fill in one additional field. Per the PPA, [redacted] Please let me know if you need any additional information. Thanks!

- Leslie

Leslie Almond
Expert Case Manager
Pacific Gas and Electric Company
(415) 973-1803

From: Halperin, Mea [mailto:Mea.Halperin@cpuc.ca.gov]
Sent: Wednesday, June 22, 2016 11:30 AM
To: Almond, Leslie
Cc: Lasko, Yakov
Subject: Update to Scheduling Protocol for Midway Sunset

This is an EXTERNAL EMAIL. Stop and think before clicking links or opening attachments.
****

***** Hi Leslie,

As a response to Data Request 8, I received a file with the scheduling protocols for about 15 of PG&E's thermal resources (attached), one of which was Midway Sunset Cogeneration. A few of the fields are blank, like the maximum number of starts per day and year. Has there been an update to this matrix, and if so, could I please get a copy?

Thank

you, Mea

Mea Halperin
Public Utilities Regulatory Analyst
Electricity Planning and Policy Branch, Office of Ratepayer Advocates
California Public Utilities Commission
415-703-1368

CONFIDENTIAL INFORMATION Protectable under General Order 66-C, and Submitted under P.U.C. §§ 454.5(g) and 583

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request	ORA_008-Q11		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_008-Q11-CONF		
Request Date:	March 24, 2016	Requester DR No.:	008
Date Sent:	April 7, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 11

[redacted]

ANSWER 11

This data response contains Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted]

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account 2015 Compliance Review
Application 16-02-019
Data Response

PG&E Data Request	ORA_016-Q08		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_016-Q08		
Request Date:	May 2, 2016	Requester DR No.:	016
Date Sent:	May 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 8

Madera Chowchilla Water and Power Authority (PG&E Log No. 25H036)

a. [redacted]

ANSWER 8

PG&E responds as follows:

a. Notional values are ascribed at the time of execution and are estimates of the potential cost to PG&E of the transaction.

b. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request	ORA_002-Q17		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_002-Q17-CONF		
Request Date:	March 4, 2016	Requester DR No.:	002
Date Sent:	March 18, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Mea Halperin

QUESTION 17

Does this amendment extend the term of the contract or change the amount of energy transmitted along the 21 kV line? If not, how does this increase in compensation prevent the need for expanding the infrastructure?

ANSWER 17

This data response contains Confidential Information pursuant to General Order 66-C, and is submitted under Public Utilities Code Sections 454.5(g) and 583.

[redacted].

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account Compliance Review
Application 16-02-019
Data Response

PG&E Data Request	ORA_008-Q13		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_008-Q13		
Request Date:	March 24, 2016	Requester DR No.:	008
Date Sent:	April 11, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

QUESTION 13

For the Geysers Power Company amendment (Log No. 01W035):

a. What is your cost estimate for the expansion or new construction of a transmission line? Please provide any supporting documentation.

b. Under what circumstances would it be necessary to build new transmission or distribution infrastructure in this area?

c. [redacted]

d. If not, please explain how the cost of building new transmission infrastructure factored into the pricing plan negotiations with Geysers.

ANSWER 13

a. Based on information provided by PG&E's distribution organization, and consulting with Calpine who recently rebuilt sections of its 21 kV line after wild fires that occurred in 2015, the estimated costs of rebuilding the line are as follows:

- Cost per mile to build 21 kV line on mountainous terrain with trees = $4.3 million per mile
- Total length of line = 4.8 miles
- Estimated cost of permits/land rights/environmental permits = $5 million
- Total number of customers = 15 (12 active and 3 inactive – 3 homes were burnt down and are currently under rebuilding effort)
- Total revenue paid to Calpine for PG&E customers on private line in 2015 = $9,400

During the 2015 wild fires, Calpine rebuilt parts of the 21 kV line that was burnt at a cost of $500,000 per mile. The cost was significantly less than the cost to PG&E would be of building a 21 kV line because Calpine did not have to obtain permits, land rights, and environmental permits, and the trees and bushes were burnt to the ground allowing easy access to rebuild lines. The discussion with Calpine did not include contractual issues or any sensitive information that could potentially compromise PG&E's negotiating ability.

b. In regard to the customers served by the 21kV line covered under the Retained Assets Agreement, [redacted]

[redacted]

[redacted] To acquire energy from another source for these customers, pay the costs of building new infrastructure, maintaining that new infrastructure, and delivering energy over new infrastructure would be greater than the price agreed to in this Amendment.

PACIFIC GAS AND ELECTRIC COMPANY
2015 Energy Resource Recovery Account 2015 Compliance Review
Application 16-02-019
Data Response

PG&E Data Request	ORA_016-Q10		
PG&E File Name:	ERRA-2015-PGE-Compliance_DR_ORA_016-Q10		
Request Date:	May 2, 2016	Requester DR No.:	016
Date Sent:	May 16, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Candice K. Chan	Requester:	Mea Halperin

CONTRACT ADMINISTRATION (CHAPTER 8)

QUESTION 10

Geysers Power Company (PG&E Log No. 33T002)

a. What was PG&E's estimated cost of potential pricing disputes related to the contract if the pricing plan had not been established?

b. With which party would the potential pricing disputes be?

c. Were there other contractual considerations not related to the pricing plan that factored into the decision to execute this amendment?

d. Is the purpose of this amendment to set up a pricing plan for the next ten years, continuing the convention from previous pricing plans in earlier PPA amendments?

e. If this is the case, why is [redacted] the justification provided in PG&E's testimony? [Footnote: PG&E ERRA RY2015 Testimony, Chapter 8, Section J, Item 4, p.8-41, lines 31-32.]

ANSWER 10

PG&E responds as follows:

a. PG&E generally does not estimate costs of potential disputes during the normal course of administering contracts or during the negotiation of amendments.

b. Neither party is precluded from initiating a dispute under an executed agreement or amendment and may do so at any time during its term.

c. PG&E is required to serve all customers in its service territory as the provider of last resort.

d. Yes, the convention followed for this amendment was to equitably reimburse the counterparty for serving PG&E’s stranded customers, and for the upkeep and maintenance of infrastructure.

e. This is the justification for the original underlying contract. The amendment updates the pricing that both parties felt was appropriate for the negotiated term.

CHAPTER 9 COSTS INCURRED AND RECORDED IN THE GREEN TARIFF SHARED RENEWABLES MEMORANDUM ACCOUNT

(Witnesses: Brian Lui and Monica Weaver)

I. INTRODUCTION AND SUMMARY

ORA reviewed chapter 11 of PG&E's 2015 Energy Resource Recovery Account (ERRA) testimony regarding Costs Incurred and Recorded In The Green Tariff Shared Renewables Memorandum Account (GTSRMA) for the Record Period February 2, 2015 through December 31, 2015.

II. RECOMMENDATIONS

ORA does not take exception to PG&E's GTSRMA for the 2015 Record Period. ORA found no required accounting adjustments and does not object to costs recorded in the GTSRMA. ORA found that the 2015 GTSRMA entries are appropriate, correctly stated, and in compliance with applicable Commission Decisions.

III. DISCUSSION

In accordance with Decision D.15-01-051, the GTSRMA allows an investor-owned utility (IOU) to collect administrative and marketing costs from Green Tariff Shared Renewables (GTSR) customers through specific charges. An IOU cannot collect unreasonable costs from customers; instead, shareholders must bear those costs.[329] PG&E incurred $2.24 million in expenses to develop and implement the GTSR Program.

PG&E will introduce the Green Tariff Shared Renewables Balancing Account (GTSRBA) in Record Period 2016 in accordance with D.15-01-051. The decision states the IOUs should use a balancing account to track generation revenue and costs for the GTSR Program.[330]

IV. ORA REVIEW OBJECTIVES, SCOPE, AND PROCEDURES

ORA reviewed PG&E's testimony, workpapers, and PG&E's responses to ORA's data requests. ORA reviewed source documents that support the costs, and expenses

[329] A.15-02-019, PG&E's Testimony Chapter 11. P. 11-1, lines 21-22.

[330] D.15-01-051 Conclusion of Law #57.

recorded in the GTSRMA. ORA's audit sample was judgmentally selected, and consisted of 15 items recorded into the GTSRMA. A "judgment sample" is a nonrandom sample selected by the auditor based on the judgment (opinion) of the auditor. When selecting a judgment sample an auditor makes judgments about various elements including but not limited to the internal control environment, exposure/ materiality, risk, and results of analytical reviews.

ORA interviewed PG&E's witnesses and performed audit tests of the following GTSR Memorandum Account items.

Table 9-1: GTSRMA Recorded Costs- February through December 2015

Line No.	Description	Amount
1	Program Management	$529,511
2	IT/ Billing System	$1,347,643
3	Energy Procurement	111,740
4	Contact Center Operations	16,419
5	Outreach	238,766
6	**Total**	**$2,244,078**[331]

V. CONCLUSION

ORA's review of the GTSRMA for the 2015 Record Period found no required accounting adjustments and does not object to costs recorded in the GTSRMA. ORA found that the 2015 GTSRMA administrative and outreach expenses are reasonable, appropriate, correctly stated, and in compliance with applicable Commission Decisions.

[331] PG&E Testimony, Table 11-1, p. 11-2.

CHAPTER 10 ENERGY RESOURCE RECOVERY ACCOUNT

(Witnesses: Brian Lui and Monica Weaver)

I. INTRODUCTION AND SUMMARY

ORA reviewed chapter 12 of PG&E's 2015 Energy Resource Recovery Account (ERRA) testimony, which includes the Renewables Portfolio Standard Costs Memorandum Account (RPSCMA) for the Record Period January 1, 2015 through December 31, 2015. PG&E's ERRA balancing account activity for the Record Period resulted in an under-collected balance of $128,314,620.

The CPUC established the RPSCMA to account for the cots it incurred to hire independent, third-party consultants who assist in implementing and administering the Renewables Portfolio Standard (RPS0 program. The CPUC reviews and approves invoices it receives from these consultants. PG&E pays the invoiced amount and records the amount into the RPSCMA. In 2015, the Energy Division staff did not submit any invoices for consulting services.[332]

II. RECOMMENDATION

ORA found that the 2015 accounting entries recorded into ERRA appropriate, correctly stated, and compliant with applicable Commission Decisions.

III. BACKGROUND

The purpose of the ERRA is to account for the actual ERRA revenues and electric procurement costs for revenue recovery. For the 2015 Record Period, the ERRA ending balance was under-collected by $128,314,620.

The ERRA's accounting entries for the Record Period are summarized in Table 10-1 below:

[332] A.15-02-019, PG&E Testimony, p. 12-4, lines 26-27.

Table 10-1
PG&E ERRA Accounting Entries
Record Period 2015

ERRA Beginning Balance	$418,280,374
ERRA Net Activity Before Interest[333]	($290,341,594)
ERRA Interest	$375,840
ERRA Ending Balance	$128,314,620
GHG Beginning Balance	$90,159,183
GHG Subaccount Net Activity After Interest	($90,159,183)
GHG Subaccount Ending Balance	$ 0
Total ERRA Ending Balance	**$128,314,620**

Recorded costs in the ERRA include the cost of utility-owned generation (UOG) fuels, Qualifying Facility (QF) contracts, inter-utility contracts, California Independent System Operator (CAISO) charges, irrigation district contracts and other Power Purchase Agreements, bilateral contracts, forward hedges, pre-payments and collateral requirements associated with electric procurement and ancillary services, along with other authorized power procurement costs. The ERRA excludes costs associated with the California Department of Water Resources (CDWR) contracts and non-fuel UOG costs. Costs recorded in the ERRA are offset by revenues from PG&E's Power Charge Indifference Adjustment (PCIA), PG&E's surplus power sales and ERRA revenues. PG&E's ERRA revenue requirement and rates are filed annually in a separate forecast proceeding and PG&E requests recovery in rates through the ERRA forecast filing.

[333] Amount includes ERRA Revenues Net of Franchise Fees and Uncollectables (FF&U) (credit) totaling $4,882,972,336 and ERRA Net Costs and Expenses (debit) totaling $4,592,630,742.

IV. ORA AUDIT OBJECTIVES, SCOPE, AND PROCEDURES

ORA reviewed PG&E's ERRA for the Record Period to determine whether entries recorded in the ERRA were appropriate, correctly stated, and compliant with applicable Commission Decisions. ORA's audit procedures included, but were not limited to the following:

- Review of PG&E's application, testimony, exhibits, workpapers and data request responses.
- Review of applicable Advice Letters, Resolutions and Commission Decisions.
- Review of monthly entries, including reviews of monthly balances recorded for each of the tariff line items in the ERRA during the year, and evaluation of monthly and annual fluctuations.
- Selection of a sample of ERRA monthly tariff line items to determine whether adequate support exists. Examination of invoices, journals, general ledgers entries, etc. for amounts recorded in the ERRA balancing account and to verify the mathematical accuracy of accounting worksheets and review of supporting documentation. ORA attended a review at PG&E's office to discuss each of the selected ERRA monthly and tariff line items in detail and to trace those line items to supporting documents.
- Review of proof of payments for selected invoices during audit process.
- Review of monthly interest rates used and the interest amount calculations.
- Determination of whether revenues and costs recorded were appropriate and stated correctly.
- Determination of whether PG&E complied with applicable Commission Decisions and Advice Letter Resolutions.
- Review of internal audit reports issued during the Record Period that pertains to the balancing account.

ORA reviewed a sampling of source documents that support the revenues, costs, and expenses recorded in the ERRA. ORA's sample was judgmentally selected and consisted of 42 monthly/ tariff line items recorded into the ERRA. A "judgement sample" is a nonrandom sample selected by the auditor based on the judgment (opinion) of the auditor. Items considered when selecting a judgment sample include auditor judgments about various elements including but not limited to the internal control environment, exposure/ materiality, risk, and results of analytical reviews.

ORA examined 42 ERRA monthly balancing account tariff line items. Tariff line items record revenues and power costs (not including CDWR contract costs) associated with PG&E's authorized procurement plan. The Commission did not record any expenses in the RPSCMA for the 2015 Record Period.

ORA discovered several discrepancies in PG&E's direct testimony through discovery and data requests. In response to those discrepancies, PG&E prepared amended testimony, which was served on April 20, 2016. ORA reviewed both the original testimony and the amended testimony. PG&E's amended testimony and data request responses clarified the discrepancies.

V. CONCLUSION

ORA found that the 2015 accounting entries recorded into ERRA were reasonable, correctly stated, and in compliance with applicable Commission Decisions.

CHAPTER 11 COST RECOVERY AND REVENUE REQUIREMENTS

(Witness: Brian Lui)

I. INTRODUCTION AND RECOMMENDATION

This testimony addresses Chapter 14 of PG&E's 2015 ERRA compliance application, which covers the Cost Recovery and Revenue Requirements for the Record Period of January 1, 2015 through December 31, 2015. PG&E is seeking cost recovery of revenue requirements totaling $6.84 million in the Diablo Canyon Seismic Studies Balancing Account (DCSSBA).

ORA performed a review to determine whether the figures provided in PG&E's Chapter 14 testimony and workpapers are appropriate, correctly stated, consistent with testimony and workpapers of PG&E's other applicable chapters, and in compliance with applicable Commission decisions.

II. BACKGROUND

PG&E is seeking cost recovery of revenue requirements totaling $6.84 million[334] in the DCSSBA[335]. Table 11-1 below summarizes the total revenue requirements requested by PG&E in this proceeding.

Table 11-1
Revenue Requirement Incremental Diablo Canyon Seismic Studies Balancing Account Costs
(Thousands of nominal dollars)

Line No	Revenue Requirements	2015
1	DCSSBA	$6,696.70
2	Interest	65.41
3	Franchise Fees & Uncollectibles	80.21
4	Total Revenue Requirement	$6,842.32

[334] Includes Franchise Fees and Uncollectibles (FF&U) and interest.

[335] A.16-02-019 PG&E direct testimony, Chapter 5.

III. ORA REVIEW OBJECTIVES, SCOPE, AND PROCEDURES

ORA reviewed[336] the costs recorded to determine whether the figures recorded in PG&E's Chapter 14 testimony and workpapers are appropriate, correctly stated, consistent with testimony and workpapers of PG&E's other applicable chapters, and in compliance with applicable Commission decisions.

ORA's audit procedures included the following:

- Review of PG&E's application, testimony, exhibits, workpapers and Master Data Request responses as well as preparation and issuance of Data Requests and review of PG&E's responses.
- Review of applicable Advice Letters and Commission Decisions.
- Selection of a sample of DCSSBA monthly line items to determine whether adequate support exists.
- Examination of invoices, general ledger entries, and related accounting records for amounts recorded in the DCSSBA.
- Verification of mathematical accuracy of accounting worksheets and supporting documentation.
- Onsite audit to review and discuss each of the ORA selected DCSSBA monthly line items in detail with PG&E staff, and to trace those line items to PG&E's general ledger.
- Review to determine whether PG&E's recorded costs were appropriate and correctly stated.
- Review to determine whether PG&E complied with applicable Decisions and Advice Letters.

On a sample test basis, ORA reviewed source documents that support costs recorded in the DCSSBA. A "judgment sample" is a type of nonrandom sample selected by the auditor based on the judgment (opinion) of the auditor. When an auditor selects a judgment sample, he/ she makes judgments about various elements including the internal control environment, exposure/materiality, and risk. ORA's "judgment sample," consisted of 22 recorded monthly line items.

[336] Addressed in ORA testimony, Chapter 5.

IV. CONCLUSION

ORA found that the entries in the Diablo Canyon Seismic Studies Balancing Account are appropriate, correctly stated, and in compliance with Commission decisions. ORA found no exceptions to the recovery requirements.

APPENDIX A

QUALIFICATIONS OF WITNESESS

QUALIFICATIONS AND PREPARED TESTIMONY
OF
CANDACE CHOE

Q.1 Please state your name and business address.

A.1 My name is Candace Choe. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Office of Ratepayer Advocates, Electricity Planning and Policy Branch.

Q.3 Briefly state your educational background and experience.

A.3 I received a B.A. in Urban Studies and Planning from the University of California, San Diego. Additionally, I received my J.D. from the University of California, Hastings College of the Law. I joined the Commission in February 2012 and worked for the Communications Division in the Broadband Policy and Analysis Branch. I joined the Office of Ratepayer Advocates' Electricity Planning and Policy Branch in June 2016.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am a project coordinator and was responsible for preparing portions of Chapter 1 (Executive Summary) of ORA's testimony.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

MEA HALPERIN

Q.1 Please state your name and business address.

A.1 My name is Mea Halperin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission (CPUC) as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates' (ORA) Electricity Planning and Policy Branch.

Q.3 Please describe your educational and professional experience?

A.3 I hold a Master of Public Administration degree in Environmental Science and Policy from Columbia University and a Bachelor of Arts degree in Political Science from the University of California, Berkeley. I joined the Commission on November 5, 2015 in ORA's Electricity Planning and Policy Branch, where I am the witness for Least-Cost Dispatch and Contract Administration for both Pacific Gas and Electric and Southern California Edison's ERRA Compliance proceedings. Prior to working at the Commission, I managed research programs, provided financial analyses, and performed program evaluations for climate and agriculture research.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am responsible for preparing Chapter 2: Least-Cost Dispatch and Economically-Triggered Demand Response and Chapter 8: Contract Administration.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

MICHAEL YEO

Q.1 Please state your name and business address.

A.1 My name is Michael Yeo. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Senior Utilities Engineer in the Office of Ratepayer Advocates (ORA).

Q.3 Briefly state your educational background and experience.

A.3 I graduated from the University Of Toronto with a Bachelor of Applied Science in Civil Engineering, and am a registered Professional Engineer. Since joining the Commission in 1992, I have worked in various assignments in ORA, Energy Division and the Consumer Protection and Safety Division. Immediately prior to joining the Commission, I worked for the California Department of Transportation.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am responsible for Chapter 3 – Utility-Owned Generation – Hydroelectric and Chapter 4 – Utility-Owned Generation – Fossil and Other Generation.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

BRIAN LUI

Q.1Please state your name and business address.

A.1 My name is Brian Lui. My business address is 505 Van Ness Ave, San Francisco, California, 94102.

Q.2By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Financial Examiner II in the Office of Ratepayer Advocates (ORA), Electricity Planning & Policy Branch.

Q.3Please describe your educational and professional experience.

A.3 I received a Bachelors of Science Degree in Biochemistry from the University of California, Riverside. I also possess a Masters Degree in Accounting from Golden Gate University in San Francisco. I joined the Commission on January 7, 2014 in ORA's Electricity Planning and Policy Branch. In ORA, I am involved in the ERRA Forecast and ERRA Compliance proceedings. Immediately prior to joining the Commission, I worked for the California State Board of Equalization as a tax auditor. I have over 4 years of experience working as an auditor in the public sector.

Q.4What is the scope of your responsibility in this proceeding?

A.4 I am sponsoring Chapter 5 of ORA's testimony on Costs Incurred and Recorded in the Diablo Canon Seismic Studies Balancing Account, co-sponsoring Chapter 9 of ORA's testimony on Costs Incurred and Recorded in the Green Tariff Shared Renewables Memorandum Account, co-sponsoring Chapter 10 of ORA's testimony on ERRA, and sponsoring Chapter 11 of ORA's testimony on Cost Recovery and Revenue Requirements as it relates to the ERRA proceeding in A.16-02-019.

Q.5Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
MONICA WEAVER

Q1. Please state your name and business address.

A1. My name is Monica Weaver. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q2. By whom are you employed and in what capacity?

A2. I am employed by the California Public Utilities Commission as an Auditor in the Office of Ratepayer Advocates, in the Energy Cost of Service and Natural Gas Branch.

Q3. Briefly describe your educational and professional experience.

A3. I have a Bachelor's of Science in Business Degree with an emphasis in Accounting from the University of Phoenix. I joined the Commission on February 8, 2016 in ORA's Energy Cost of Service and Natural Gas Branch.

Q4. What is the scope of your responsibility in this proceeding?

A4. I am responsible for portions of Exhibit ORA-6, 9 and 10, which addresses PG&E's ERRA testimony Chapter 6 Generation Fuel Costs and Electric Portfolio Hedging as well as co-sponsoring Chapter 11 Costs Incurred and Recorded in the Green Tariff Shared Renewables Memorandum Account and Chapter12 Summary of Energy Resource Recovery Account.

Q5. Does that complete your prepared testimony?

A5. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

AYAT OSMAN, Ph.D.

Q.1 Please state your name and business address.

A.1 My name is Ayat Osman. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates' (ORA) Electricity Planning and Policy Branch.

Q.3 Briefly state your educational background and experience.

A.3 I have a Ph.D. in Civil Engineering from the University of Pittsburgh (2006), Dissertation titled "Life Cycle Optimization Model for Integrated Cogeneration and Energy Systems Applications in Buildings." I also have two Master of Science Degrees: M.Sc.in Environmental Engineering (2002), and M.Sc. in Environmental Science and Management from Duquesne University (2000). I have a Bachelor's of Science in Chemistry from the American University in Cairo (1998). I worked in Energy Division in the Energy Efficiency Section as Public Utilities Regulatory Analyst from 2007 to 2012. I worked as an associate in energy consulting at Cadmus from 2012 to 2014. I joined ORA in 2014 to present.

Q.4 What is the scope of your responsibility in this proceeding?

A.4 I am responsible for Chapter 7: Greenhouse Compliance Instrument Procurement: Procurement of Compliance Instruments and Greenhouse Gas Costs.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.