Docket:		A.13-02-023
Exhibit Number	:	.
Commissioner	:	Michel Peter Florio
Admin. Law Judge	:	Stephen C. Roscow
DRA Project Mgr.	:	Michael Yeo
	:	

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Testimony on Application of Pacific Gas and Electric Company 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, 2012 (U39E)

(PUBLIC VERSION)

A.13-02-023

San Francisco, California
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MEMORANDUM

This testimony was prepared by the Division of Ratepayer Advocates (DRA) of the California Public Utilities Commission (Commission or CPUC) in Pacific Gas & Electric's (PG&E) 2012 Energy Resource Recovery Account (ERRA) Compliance Application (A.13-02-023). PG&E's Application requests a Commission finding that PG&E made appropriate entries to its ERRA balancing account for calendar year 2012 (the Record Period) and that it complied with its obligations regarding its contract administration, administration of utility owned generation (UOG), and least-cost dispatch (LCD) of electric generation resources. DRA presents its analysis and recommendations associated with the applicant's request. Except for the multi-year Diablo Canyon Seismic Studies Balancing Account, this testimony is exclusively focused on the 2012 Record Period and is based on DRA's analysis of information submitted by PG&E regarding the year 2012 and no other period of time, including PG&E's testimony and workpapers submitted with its application, responses to data requests, meet-and-confer notes, and field-visit presentations. As PG&E's Application did not include evidence for operations outside the 2012 Record Period, DRA's testimony does not consider facts from before or after the 2012 Record Period.

Michael Yeo served as DRA's project coordinator in this review and was responsible for the overall coordination in the preparation of this document. The qualifications of DRA's witnesses and their testimony declarations are contained in Appendix A of this report.

The issues that DRA reviewed are listed below and summarized in Chapter 1. For those issues or topic areas for which no testimony is filed, DRA does not have any recommendation or disallowance.

List of DRA Witnesses and Respective Chapters

Chapter #	Description	Witness
1.	Summary	Michael Yeo
2.	Utility Owned Generation – Nuclear & Hydro	Yakov Lasko
3.	Utility Owned Generation – Fossil	Ravinder Mangat
4.	QF Contract Administration	Yakov Lasko & Colin Rizzo
5.	Least-Cost Dispatch	Ravinder Mangat
6.	Diablo Canyon Seismic Studies Balancing Account	Grant Novack
7.	Market Redesign & Technology Upgrade (MRTU)	Grant Novack
8.	Balancing Account Audit	Grant Novack
9.	Maximum Disallowance for SOC4 Violation	Michael Yeo

List of Topic Areas with No DRA Testimony

#	Topic Area	DRA Reviewer
1.	Non-QF Contract Administration	Ravinder Mangat
2.	CAISO Settlements and Monitoring	Yakov Lasko
3.	Greenhouse Gas Compliance Instrument Procurement	Jordan Parrillo
4.	Demand Response Contract Administration	Yakov Lasko

Chapter 1

Witness: Michael Yeo

EXECUTIVE SUMMARY

This Testimony includes results of the Division of Ratepayers Advocates' (DRA's) review of Pacific Gas and Electric Company's (PG&E) Energy Resource Recovery Account (ERRA) Compliance Application for the period from January 1, 2012 to December 31, 2012 (Record Period). PG&E filed this application pursuant to Decision No. 02-10-062, in which the Commission required certain utility procurement activities to be reviewed annually in an ERRA proceeding.

According to the Commission the purpose of the ERRA annual review is, generally: (1) to review PG&E's energy procurement activities were consistent with the least-cost dispatch principles set forth in Standard of Conduct No. 4 (SOC#4);[1] (2) to determine if PG&E accurately recorded procurement expenses that are eligible to be recovered through the ERRA balancing account; (3) to review entries in the ERRA balancing account to ensure such entries are accurate and consistent with Commission decisions; and (4) to determine through a reasonableness review if PG&E reasonably administered its Qualifying Facilities (QF) and non-QF contracts, and if the operation of its utility owned generation units, including maintenance outages, was reasonable.[2]

PG&E filed its application on February 28, 2013, requesting Commission approval for activities that occurred during the 2012 Record Period. The scope of DRA's review of PG&E's application is exclusively focused on the 2012 Record Period and includes UOG fuel expenses and operations, contract administration,[3] Least Cost Dispatch (LCD)

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[1] D.02-10-062, p. 51 (Oct. 24, 2002) ("[U]tilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.").

[2] *See*, D.11-10-002 Appendix at p. 3.

[3] Contract administration includes a review of Department of Water Resources (DWR) contracts, existing Qualifying Facilities (QF) contracts, inter-utility contracts, bilateral contracts, and renewable contracts.

of electric generation resources, and an audit of the balancing account entries. In addition, DRA also looked at other non-ERRA issues summarized below.

In its application, PG&E requests recovery of the amounts recorded in the ERRA as of December 31, 2012, which includes $74.797 million in over-collections recorded in the 2012 Record Period. PG&E's over-collection figure derives from adding $84.594 million in ERRA over-collection in the period ending on December 31, 2011 to $3.603 billion in 2012 ERRA revenues and $109,857 in interest credit, minus $3.613 billion in 2012 ERRA expenses (including the Power Charge Indifference Adjustment, which reduced total expenses). In addition, PG&E seeks approval to recover the balances of the following accounts:

- the Market Redesign and Technology Upgrade Memorandum Account ("MRTUMA")
- the Diablo Canyon Seismic Studies Balancing Account ("DCSSBA"); and
- PG&E's Greenhouse Gas Compliance Instrument Procurement.

DRA, this report, recommends disallowances in UOG, QF Contract Administration and the DCSSBA. The summary of these allowances are listed below.

A. SUMMARY OF OBSERVATIONS AND RECOMMENDATIONS

The following summary of observations and recommendations are sponsored by the witnesses in subsequent chapters, and this summary is offered strictly for the reader's convenience.

1. Utility Owned Generation – Nuclear and Hydro

DRA found two substantive indications of PG&E's failure to act as a reasonable manager would have acted in PG&E's operation, excluding dispatch, of its UOG facilities or its outages. Accordingly, DRA recommends disallowances for:

1. Diablo Canyon Power Plant Unit 2, a 1,118 MW unit that experienced a 4.4-day forced outage on October 11, 2012, in the amount of $3,238,185; and

2. Belden Powerhouse, a 125 MW unit that tripped off-line on July 13, 2012 until September 16, 2012, in the amount of $1,968,220.

2. Utility Owned Generation – Fossil

DRA reviewed outage information from PG&E's [redacted]. DRA found that one of the outages at Humboldt Bay Generating Station (HBGS) required further investigation. [redacted]

In connection with this outage at HBGS, DRA recommends a total combined disallowance of $1.7 million, which includes:

- Foregone energy costs of $87,000, and
- Capital and labor costs of $1.61 million.

3. Non-QF Contract Administration

DRA has no recommendation or disallowance on this area of the application.

4. QF Contract Administration

DRA recommends two disallowances and a corrective action with regard to PG&E's administration of QF contracts. DRA concluded that PG&E did not prudently administer the Amedee Geothermal Venture 1 (AGV1) and the Wendel Energy Operations 1 (WEO1) contract. DRA recommends a disallowance of $20,062 for the AGV1 contract and a disallowance of $106,109.30 for the WEO1 contract.

In addition, DRA recommends that PG&E adopt oversight procedures to ensure that its future contracts are prudently administered. PG&E's requested recovery of [redacted] derived from the contract with the University of California, San Francisco campus (UCSF), should be approved subject to PG&E's adoption of the aforementioned corrective action, which will prevent future adverse impacts for ratepayers.

5. Least-Cost Dispatch

DRA examined PG&E's filing to determine whether PG&E had met their least cost obligations arising from SOC 4. This review of PG&E's testimony, master data responses and work papers, reveals that PG&E did not include a performance evaluation or other type of quantitative analysis that demonstrated PG&E's effectiveness in achieving the least-cost dispatch standard in the record year. It is not possible to conclude that PG&E has met the LCD standard without reviewing this type of analysis.

Given the voluminous amounts of data included in PG&E's filing related to their dispatch activities, DRA's analysis was necessarily limited, and focused on reviewing a sample of the energy bids submitted by PG&E's dispatchable fossil fueled resources to CAISO in the day-ahead market. Based on this analysis, in general, PG&E submitted their costs in a cost effective manner, although a number of procedural issues were discovered that PG&E should address in order to ensure that errors in calculating these energy bids are minimized.

DRA recommends corrective action with regard to PG&E's LCD procedures to resolve a significant number of occurrences where PG&E has submitted incorrect bids (*i.e*. bids that are not at incremental cost) into the CAISO market from their [redacted]

[redacted] PG&E acknowledged that these incorrect calculations were due to a number of reasons, including software malfunctions and human errors.

In relation to [redacted], DRA requires that PG&E present a compliance filing 30 days subsequent to the final decision in this proceeding, to:

- demonstrate the level of progress that has been made in identifying a comprehensive solution to these [redacted] problems identified in this testimony, and
- set out a timeline stating when each solution will be finalized and implemented.

6. CAISO Settlements and Monitoring

DRA has no recommendation or disallowance on this area of the application.

7. Demand Response Contract Administration

DRA has no recommendation or disallowance on this area of the application.

8. Greenhouse-Gas Compliance Instrument Procurement

DRA has no recommendation or disallowance on this area of the application.

9. Diablo Canyon Seismic Studies Balancing Account (DCSSBA)

The following table presents costs recorded in the DCSSBA through December 31, 2012, by category:

Line No.	Category	Recorded Costs as of 12/31/2012 ($ Million)
1	Seismic Survey Design	$0.85
2	Offshore 2-D/3-D LESS	$12.52
3	Offshore 3-D HESS	$8.2
4	Onshore 2-D	$14.32
5	OBS Installation	$0.99
6	Project Management	$3.01
7	Total	$39.89

DRA recommends disallowance of the $3.76 million costs PG&E incurred and recorded for survey vessel contracting and NQA for seismic data acquisition. Under the facts and circumstances, the $3.76 million costs do not qualify as operation and maintenance expenses incurred in the ordinary and prudent course of business. Considering DRA's recommendation that the $3.76 million should not be recovered in rates, DRA recommends PG&E recover in rates $36.13 million total expenses incurred during 2011-2012 and not the $39.89 million total that PG&E has recorded. Of the $36.13 million total expenses incurred, PG&E has already recovered $14.41 million in 2011 and 2012 rates. Therefore, DRA recommends that the difference of $21.72 million plus the Franchise Fees and Uncollectible Accounts (FF&U) of $234,359 (using the factor 0.010790) be included in rates in this proceeding.

10. Market Redesign & Technology Upgrade (MRTU)

PG&E requests that the California Public Utilities Commission fine $3.583 million in capital expenditures and $0.064 million in expense as incremental amounts are reasonable and recoverable in rates. DRA's review did not note any items of a material nature requiring adjustments to PG&E's recorded incremental capital expenditures of $3.583 million associated with the CAISO's December 2011. DRA's review did not note any items of a material nature requiring adjustments to PG&E's recorded incremental IT expenses of $0.064 million, which supported the capital projects, as well as PG&E's initiated specific work in order to effectively operate in the CAISO's newly redesigned markets.

11. ERRA Balancing Account

The ERRA balancing account activity for the Record Period (January 1, 2012 to December 31, 2012) resulted in an over-collected balance of $74,797,023. DRA found no required accounting adjustments and no exceptions to the recovery requirements.

12. Maximum Disallowance for SOC4 Violation

DRA recommends, for this Record Period, that the maximum disallowance for PG&E's violation(s) of Standard of Conduct 4 be $162,212,000.

Chapter 2

Witness: Yakov Lasko

PG&E'S MANAGEMENT OF UTILITY-OWNED GENERATION – NUCLEAR and HYDRO

A. SUMMARY AND RECOMMENDATIONS

This chapter addresses the prudence of PG&E's management of its nuclear and hydro utility-owned generation (UOG), with an emphasis on outage avoidance and mitigation, from January 1, 2012 to December 31, 2012 (the Record Period). In doing so, DRA reviewed generation outage information, including the underlying factors for certain outages, to ensure that ratepayers do not suffer any economic losses due to unreasonable UOG management errors or omissions.

After reviewing PG&E's testimony and responses to its discovery requests, DRA found two substantive indications of PG&E's failure to act as a reasonable manager would have acted in PG&E's operation, excluding dispatch, of its UOG facilities or its outages. Accordingly, DRA recommends disallowances for:

1. Diablo Canyon Power Plant Unit 2, a 1,118 MW unit that experienced a 4.4-day forced outage on October 11, 2012, in the amount of $3,238,185; and
2. Belden Powerhouse, a 125 MW unit that tripped off-line on July 13, 2012 until September 16, 2012, in the amount of $1,968,220.

B. DISCUSSION

During the course of the Record Period, PG&E experienced one refueling outage and two forced outages at its Diablo Canyon Power Plant (DCPP) nuclear facility that lasted longer than 24 hours.[4] Over the course of the Record Period, "at PG&E's Large Hydro conventional facilities, there were 25 forced outages with durations longer than 24 hours occurring at 17 different units. Of these 25 forced outages, nearly half,

[4] PG&E Testimony, Chapter 6, pp. 8-9.

11 outages, were the result of the two extraordinary events."[5] Finally, "during the record period, there were nine forced outages at Helms units lasting longer than 24 hours."[6]

In reviewing the utility's UOG costs for recovery, DRA considered whether or not the acts of PG&E comported with "what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act."[7]

DRA found that PG&E failed to show that it acted as a reasonable manager would have with respect to the (1) DCPP forced outage that occurred on October 11, 2012 and (2) Belden Powerhouse forced outage that occurred on July 13, 2012. Based on the reasonable manager standard, the acts of the utility with respect to the three outages listed above must have been reasonable, made with prudence and logic, and based on the information at hand when faced with a need to make the decision during the Record Period. DRA presents its findings on the two forced outages below and its recommendation for disallowances.

1. Diablo Canyon Power Plant (DCPP) Forced Outage of October 11, 2012

a. Events Leading to the Incident and Incident Description

PG&E reported that, [redacted]

[5] PG&E Testimony, Chapter 3, p. 33, lines 3-7.

[6] PG&E Testimony, Chapter 3, p. 41, lines 13-14.

[7] D.10-07-049, p. 14.

[redacted],[8] [redacted].[9] From PG&E's Root Cause Evaluation report dated May 2, 2013, it appears that [redacted]. This is further confirmed by PG&E's Licensee Event Report to US Nuclear Regulatory Commission, where PG&E explained that [redacted][10]

PG&E's engineers did not follow the guidelines of the [redacted]. PG&E's imprudent management resulted in its engineers departing from a [redacted] This failure by PG&E led to the 4.4-day forced outage on October 11, 2012 costing ratepayers approximately [redacted]. According to the Root Cause Evaluation, [redacted]

> [redacted]

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[8] Flashover is an unintended electric discharge, usually manifested in an electrical arc, over or around the surface of an insulator.

[9] *See* Exhibit 2.1: PG&E's DCPP Root Cause Evaluation Rev.2, p.3

[10] *See* Exhibit 2.2: PG&E's Licensee Event Report 05000-323, June 26, 2013, p. 1, 4.

[redacted]

The Root Cause Evaluation also found that [redacted]”[12] This report concluded that:

[redacted][3]

[redacted]

PG&E identifies three additional contributing causes to the DCPP forced outage in its Root Cause Evaluation. They are:

[redacted]

[11] See Exhibit 2.3: (INPO) 10-005, Principle 4.

[12] See Exhibit 2.1: PG&E’s DCPP Root Cause Evaluation Rev. 2, p. 39.

[13] *Id.* at p. 39.

[14] *Id.* at p. 7.

DRA found that the first of these three causes (that [redacted]) is the most serious one and, as discussed below, it is directly related to the forced outage.

b. Analysis of the Outage

[redacted].”[15]

According to PG&E, both the Institute of Electrical and Electronics Engineers (IEEE) and International Electrotechnical Commission (IEC) standards provide recommendations for [redacted]:

[redacted]”—

[15] *Id.* at p. 3.

[16] *Id.* at p. 3–4.

PG&E' Root Cause Evaluation Report provided the table below, which compares the components that were investigated.[17]

Table 1: [redacted]

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

As the above table shows, PG&E failed to adhere to industry standards and, as a result, did not maintain an adequate [redacted] This requirement is one of the three key factors that PG&E had to accurately consider to ensure that the [redacted] Based on PG&E's failure to follow industry's recommendations for [redacted], DRA found that PG&E did not act prudently and in accordance with the reasonable manager standard.

PG&E also identified several assumptions and other factors in its Root Cause Evaluation report that either caused or contributed the actual creepage distance to be lower than the recommended industry standards. The comments on these assumptions, as noted in the Root Cause Evaluation, were:

[redacted]

[17] *Id*. at p. 53.

[redacted]

[redacted]

[redacted]

[redacted]

With regard to points (i) and (ii), PG&E relied on external actors and made several assumptions about the [redacted] without (a) going through an independent verification to ensure the assumptions were appropriately conservative and consistent with recommended IEEE and IEC codes and standards, and (b) validating these assumptions through analysis or testing. In this respect, PG&E's Root Cause Evaluation Report correctly concluded that [redacted]

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

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

[redacted] by thorough independent verification and validation of assumptions that were made about the [redacted] Had PG&E performed testing on [redacted] its engineers would have noticed that the [redacted] because the assumptions of [redacted] were too optimistic.

In fact, PG&E’s Root Cause Evaluation Report stated that [redacted],” and concluded that [redacted] in PG&E’s outage.[20] Based on PG&E’s test results, DRA concluded that performing [redacted] and other tests may have refuted internal PG&E’s engineers’ and vendor’s assertions that, [redacted].[21] Significantly, PG&E noted that [redacted][22] [redacted]

In addition, PG&E’s engineers did not adequately consider the well-known IEEE and IEC standards on the appropriate [redacted], which should have mitigated the outdated or inadequate information found in PG&E’s [redacted], as described in factors (iii) and (iv) above. Had IEEE and IEC standards been considered and PG&E performed independent scientific testing

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[20] *Id*. at p. 12.

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

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

and analysis of [redacted], PG&E Engineering would not have so readily accepted opinions and assumptions by its vendor and experts that [redacted]

Regarding factor (v), DRA understands that during the selection [redacted] PG&E asserts that [redacted][23] However, it is unclear from the Root Cause Evaluation Report why PG&E did not [redacted] Neither is it clear why PG&E did not consider [redacted]. DRA suspects that these questions were not considered because a conclusion was reached that the [redacted]. If PG&E's engineers had acted as a reasonable manager, they would have performed an actual validation of assumptions through actual testing of [redacted], as well as consulted the IEEE and IEC standards on [redacted] Had this conclusion been reached, a reasonable manager would have, at that point, either find another vendor or [redacted]

Finally, PG&E's reliance on an inadequate [redacted] on the part of Engineering—which is one of the three Contributing Causes to the DCPP forced outage

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

identified by PG&E—, resulted in an underestimation of the [redacted] and contributed to the event. In a response to DRA, PG&E explains that

> [redacted]—

DRA's understanding of this explanation is that PG&E did not act prudently and in accordance with a reasonable manager standard [redacted] but simply relied on the engineer's interpretation of [redacted]. The engineer relied on his or her interpretation of the [redacted] to make assumptions regarding the [redacted] with respect to IEEE standards. Assumptions based on [redacted] are an inferior method of deduction compared to scientific analysis and testing of [redacted], which is what a reasonable manager should have done.

c. Diablo Canyon Forced Outage Disallowance

For the Record Period, DRA recommends the Commission to impose a $3,238,185 disallowance for the duration of the forced outage that occurred on October 11, 2012 due to PG&E's imprudent management of Diablo Canyon Power Plant. DRA used the following calculation to arrive at an appropriate Opportunity Cost of Foregone Energy during the Forced Outage disallowance amount:

A * (P – F) = Opportunity Cost of Foregone Energy during the Forced Outage

Where,

A = The average self-schedule bid for Diablo Canyon Unit 2 for 2012 Record Period, which is approximately [redacted] MW. Because

[24] *See* Exhibit 2.4: Data Request, DRA_011-07 Question 11.1.2.6.1 and 11.1.2.6.2 (emphasis added).

DCPP is a base-load unit that is expected to run continuously close to its maximum output, DRA finds that the average self-schedule bid for DCPP Unit 2 is a reasonable measure. DRA notes that while DCPP Unit 2 Net Qualifying Capacity (NQC) is [redacted] MW, DRA used instead the average amount of net energy that the unit would be able to deliver to the grid, which DRA believes to be approximately the average of PG&E's self-schedule's bids into the CAISO market for 2012.

P = the locational marginal price (LMP) of energy per MWh from [redacted]. The price will vary for each hour of the forced outage.

F = the avoided cost of nuclear fuel, which is approximately $[redacted]/MWh. The calculation for the avoided cost of nuclear fuel is based on DCPP Unit 2 nuclear fuel expenses ([redacted])[25] and the electrical energy in MWh delivered to the grid from DCPP Unit 2 [redacted] MWh).[26]

Accordingly, based on DRA's assumptions, the total Opportunity Cost of Foregone Energy During the Forced Outage for all hours from [redacted] is $3,179,422.61.

DRA used the following calculation to arrive at an appropriate Opportunity Cost of Foregone Energy during the Ramp-Up disallowance amount:

U * (P – F) = Opportunity Cost of Foregone Energy during the Ramp-Up of DCPP Unit 2

Where,

U = is the unutilized potential output and is measured as the difference between the average self-schedule bid for Diablo Canyon Unit 2 for 2012 Record Period, which is approximately [redacted] MW and the total net award received by DCPP Unit 2 from CAISO for each specific hour as DCPP Unit 2 was ramping up to its full potential output.

P = the locational marginal price (LMP) of energy per MWh from [redacted] The price will vary for each hour of the forced outage.

[25] PG&E's Testimony, p. 8-23, line 33.

[26] *See* Exhibit 2.5: Data Request, MDR001-Q009_Atch-CONF Question 1.1.9.18.

F = the avoided cost of nuclear fuel, which is approximately $[redacted]/MWh.

Accordingly, based on DRA's assumptions, the total Opportunity Cost of Foregone Energy during the Ramp-Up of Unit 2 to its full output (measured by DRA using the average self-schedule bid for DCPP Unit 2 for 2012) for all hours from [redacted] is $686,848.38.

The final component in determining the appropriate disallowance amount is capacity-related costs and other miscellaneous market-related charges caused by October 11, 2012 force outage. The summary of these costs were provided by PG&E and are shown in the table below, per DRA's Data Requests:[27]

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

DRA contends that CRR Hourly Settlement credits should not be included in the final calculation of costs because Congestion Revenue Rights are a financial hedge and therefore should not be considered as a component of PG&E's opportunity cost of foregone energy nor capacity-related charges. Moreover, DRA holds that PG&E's hedging strategies with respect to CRRs need to be considered on a portfolio-wide basis. Therefore, the adjusted grand total for the table above would be a credit to PG&E equivalent to $628,085.95.

[27] *See* Exhibit 2.6: DRA_011-11, DRA_011-12, DRA_011-Q11Atch01-CONF.

The table below summarizes PG&E's total costs as a result of Diablo Canyon forced outage that occurred on October 11, 2012:

DIABLO CANYON UNIT 2 TOTAL COST		
[redacted]	[redacted]	[redacted]
	Sub-Total (+ positive = charge, - negative = credit)	**($628,085.95)**
	Total Opportunity Cost of Foregone Energy During the Forced Outage	**$3,179,422.61**
	Total Opportunity Cost of Foregone Energy During the Ramp-Up	**$686,848.38**
GRAND TOTAL (+ positive = charge, - negative = credit)		**$3,238,185.04**

2. Belden Powerhouse outage of July 13, 2012

According to PG&E's Testimony,

> On July 13, 2012, Belden Powerhouse tripped off-line due to a failed pipe fitting on the bearing oil lubricating system. The failed fitting allowed the oil in the upper guide bearing tub to drain to the point where the bearing excess high temperature alarm tripped the unit. The bearing tub had an oil level monitoring device that should have tripped the unit before the bearing reached an excessive temperature, however, this instrumentation failed to operate as the oil level fell.[28]

PG&E indicates that the subsequent oil cleanup work and replacement of damaged equipment lasted a little over two months and Belden Powerhouse did not return to service until September 16, 2012.

[28] PG&E Testimony, Chapter 3, p. 35, lines 18–27.

According to PG&E’s Root Cause Analysis (RCA) of Belden Oil Spill & Unit Trip Investigation, [redacted]”.[29]

[redacted]

DRA found that, if the [redacted] had not failed, the outage would not have happened. But even if the [redacted] failure had occurred, the magnitude of the duration and the impact of the forced outage would have been significantly diminished if at least one of the [redacted] had been operational.

PG&E failure to act as a reasonable manager by not verifying whether or not the [redacted] were working as designed when the other [redacted] was turned off and PG&E’s failure to take into account [redacted] before determining the appropriate place where to install the [redacted] led to a 65.35-day forced outage that cost ratepayers approximately $[redacted].

a. Incident Description

PG&E provides the following description of the incident that occurred on July 13, 2012 and that led to the 65.35-day forced outage at the Belden Powerhouse:

[redacted]

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[29] *See* Exhibit 2.7: PG&E’s Belden Powerhouse Root Cause Analysis, p. 3.

[30] *Id*. at p. 3.

[redacted].

b. Analysis of the Outage

DRA found that a number of reasons contributed to the forced outage:

1. Equipment malfunction, not caused by human error or judgment;
2. Lack of appropriate contingency plans, safeguards or procedures to ensure that if one of the monitoring components is taken offline, the backup component is operational and the equipment that was being monitored was functioning as designed; and
3. Equipment malfunction, caused in part by human error or poor judgment.

One of the contributing factors to the forced outage was "[redacted]"[32] This request was properly requested and granted to PG&E's staff by management. PG&E reported that these [redacted] were attributed to the following factors:

[redacted]

[31] *Id.*at p.3 (emphasis added).

[32] *Id.* at p.5, lines 192–195.

[redacted].[33]

As PG&E indicated, the [redacted] was disabled on May 16, 2012 because "[redacted]."[34] PG&E acknowledged that

[redacted].[35]

PG&E's failure to ensure that the [redacted] were functioning properly after the [redacted] was disabled was a major factor contributing to the severity and the duration of the forced outage at the Belden Powerhouse from July 13, 2012 to September 16, 2012.

PG&E provided the following explanation for its failure to detect that the [redacted] were inoperative:

[redacted] —

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[33] *Id.*

[34] *See* Exhibit 2.8: Data Request, DRA_012-02 Question 12.1.1.2.

[35] *See* Exhibit 2.9: Data Request, DRA_019-12 Question 19.1.2.5 (emphasis added).

[36] *See* Exhibit 2.10: Data Request, DRA_019-09, Question 19.1.2.2.

Given that the time period between the auto tests conducted by PG&E on March 7, 2012 and the time of the unit trip on July 13, 2012 is four months, PG&E's failure to perform additional tests on the [redacted] would have been reasonable *if* the [redacted] to PG&E's knowledge was *still* operational. However, once PG&E disabled the [redacted] for maintenance, the [redacted] and should have been tested again. DRA found that, had the [redacted] been operational, the resulting duration of a forced outage caused by the [redacted] failure would have been significantly diminished because PG&E would have been alerted to a [redacted] before a significant damage to equipment could occur due to [redacted]

PG&E believes that the [redacted] became inoperable on March 7, 2012 *during* the routine testing because [redacted][37] Based on the explanation provided, DRA suspects that PG&E's staff could have discovered the pinched wire performing a simple visual inspection of the [redacted] after removing the cover since it is PG&E's belief that the wire was pinched by the [redacted]. Moreover, PG&E acknowledged the importance of the proper operation of the [redacted] to the plant's operation because [redacted].”[38] The shutdown of a unit is crucial because the [redacted] can damage equipment and prolong the outage, as happened in this case.

[37] *See* Exhibit 2.7 p. 3, lines 104–108.

[38] *See* Exhibit 2.09: Data Request, DRA_019-12 Question 19.1.2.5.

Finally, PG&E failed to show that they have documentation detailing proper contingency plans, safeguards, or procedures to guide PG&E's personnel regarding the equipment that should be inspected to prevent potential incidents when the [redacted] becomes purposefully disabled or inoperable.[39] Proper documentation would have provided PG&E's personnel with a description of the combinations of reasonable occurrences and conditions that would result in an unwanted event following the disabling of [redacted]

DRA concluded that PG&E failed to show that it acted as a reasonable manager would have because PG&E:

1) [redacted][40] [redacted] and

2) Failed to provide written instructions to powerhouse personnel detailing which equipment they should test/inspect to safeguard against [redacted]

Had PG&E visually inspected and/or tested the [redacted], and found fault inside, it is reasonable to assume that PG&E would have been able to detect the [redacted] early on, before the extensive damage to powerhouse's equipment could occur and needlessly prolonging the outage. However, PG&E's omissions [redacted]"[41]

In addition, PG&E failed to show that its actions to avoid the equipment malfunction that occurred on the [redacted] were reasonable. As described above, PG&E reported that a [redacted]

[39] *Id.*

[40] *See* Exhibit 2.11: Data Request, DRA_012-01 Question 12.1.1.1.

[41] *See* Exhibit 2.7, p. 2, lines 33–37.

[redacted][42] In its Root Cause Analysis, PG&E explained the [redacted] failure stating:

> [redacted]
>
> [redacted]
>
> [redacted]

In its RCA report, PG&E admitted that [redacted] and recommended, as a corrective action, to [redacted] as well as [redacted]

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[42] *Id*. p. 3, lines 95–101.

[43] *Id*. pp. 4-5, lines 155–276 (emphasis added).

[redacted][44] PG&E failed to show that it acted as a reasonable manager would have acted at the it made decisions with regard to the equipment because PG&E:

1. [redacted], even though it should have been reasonable to conclude that pumps vibrate in the course of their normal operations, and that the [redacted] would increase the risk of cyclic stresses that could cause fatigue failure;
2. Failed to take into account [redacted] before determining the appropriate place where to install the [redacted]; and
3. Failed to ensure that the final installed schematics of the [redacted] would not deviate from the original design[45].

In conclusion, DRA found that PG&E failed to show that its decision to install [redacted] was reasonable and consistent with the "reasonable manager" standard.

c. Belden Powerhouse Forced Outage Disallowance

For the Record Period, DRA recommends the Commission to impose a $1,968,220 disallowance for the duration of the forced outage that occurred on July 13, 2012 due to PG&E's imprudent management of Belden Powerhouse. DRA used the following calculation to arrive at an appropriate disallowance amount:

(A * H) * P = Disallowance

Where,

A = the average total net award in MWs Belden Powerhouse would have reasonably been able to receive for each hour during the duration of the forced outage, which is approximately [redacted] MW. DRA used a proxy period of Belden Powerhouses' total net awards (energy, ancillary services and residual unit commitment) [redacted], for estimating the average total net award for each hour;

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[44] *Id.* p. 12.

[45] DRA Data Request: DRA_019-02, Question 19.1.1.3.

H = the duration of the forced outage in hours from [redacted]. This duration is equivalent to approximately [redacted] days, which is about [redacted] hours;

P = the average locational marginal price (LMP) of energy per MWh from [redacted] at Belden Powerhouse's price node (PNode) BELDEN_7_B1, which is approximately $[redacted]/MWh.

Based on DRA's calculation, the appropriate value for the disallowance is $1,968,220.

Chapter 2 Exhibit Index [redacted]	
Exhibit 2.1	[redacted] (To be distributed separately due to file's large size and frequent references in DRA's testimony.)
Exhibit 2.2	[redacted]
Exhibit 2.3	Institute of Nuclear Power Operations, 10-005, Principle 4.
Exhibit 2.4	Data Request, DRA_011-07 Questions 11.1.2.6.1 and 11.1.2.6.2.
Exhibit 2.5	[redacted].
Exhibit 2.6	Data Request, DRA_011-11, DRA_011-12, [redacted]
Exhibit 2.7	[redacted]) (To be distributed separately due to file's large size and frequent references in DRA's testimony).
Exhibit 2.8	[redacted]
Exhibit 2.9	[redacted]
Exhibit 2.10	[redacted]
Exhibit 2.11	[redacted]

C. CONCLUSIONS AND RECOMMENDATIONS

1. Diablo Canyon Power Pant (DCPP) Forced Outage of October 11, 2012

DRA finds that PG&E failed to show that it acted as a reasonable manager would have at the time the decision was made to replace [redacted]

[redacted]

1) Failed to consult IEEE and IEC standards on the [redacted]

2) Failed to adhere to sound engineering principles by not verifying and validating the assumptions that were made about the capability of [redacted] and

3) Failed to correctly estimate the [redacted]

DRA recommends that the Commission make a disallowance in the amount of $3,238,185 based on the finding that PG&E did not, in accordance with the reasonable manager standard, prudently manage its Diablo Canyon Power Plant facility.

2. Belden Powerhouse outage of July 13, 2012

DRA concluded that PG&E failed to show that it acted as a reasonable manager would have because PG&E:

1) [redacted];

2) Failed to provide written instructions to powerhouse personnel detailing which equipment they should test/inspect to safeguard against [redacted]

In addition, DRA found that PG&E failed to show that its decision to install [redacted] was reasonable and consistent with the "reasonable manager" standard.

DRA recommends that the Commission make a disallowance in the amount of $1,968,220 based on the finding that PG&E did not, in accordance with the reasonable manager standard, prudently manage its Belden Powerhouse facility.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

EXHIBIT 2.3 (partial)

Principles for Maintaining an Effective Technical Conscience INPO 10-005

4. Engineers adhere to sound engineering principles.

Engineers ensure products are of high quality when they "sign off" on the products as complete. Engineers develop technical products, recommendations, and decisions using appropriate facts, engineering practices, codes, standards, operating experience, and review/verification processes. The probabilities and consequences of negative outcomes are thoroughly evaluated, documented, and communicated.

Attributes:

- Engineers use factual information from diverse sources to develop technical products, recommendations, and decisions. This information is independently verified as part of the engineering review process.

- Technical products, recommendations, and decisions are carefully developed using approved and accepted codes, standards, and analytical tools. Design inputs, methodologies, and the bases for results are documented, independently verified, and formally communicated to appropriate stakeholders. Engineers systematically apply critical feedback, human performance techniques, and additional reviews to ensure high-quality products and to minimize the likelihood of consequential problems.

- Assumptions and engineering judgment are fully documented and receive thorough independent verification to ensure they are appropriately conservative and consistent with approved codes and standards. Key assumptions and the use of engineering judgment are clearly communicated to decision-makers to ensure the limitations of the technical analyses are fully understood. When possible, assumptions are validated through analysis or testing.

- Engineers develop, maintain, and exercise their expert knowledge of plant operating limits, design requirements, and industry codes and standards.

- Engineers recognize the limits of their technical expertise and clearly communicate to decision-makers when they are offering advice or opinions outside of their area of expertise. Engineers recognize that their signature represents professional endorsement of a quality product.

6

EXHIBIT 2.4

PACIFIC GAS AND ELECTRIC COMPANY
2012 Energy Resource Recovery Account Compliance Review
Application 13-02-023
Data Response

PG&E Data Request No.:	DRA_011-07		
PG&E File Name:	ERRA-2012-PGE-Compliance_DR_DRA_011-Q07		
Request Date:	May 29, 2013	Requester DR No.:	011
Date Sent:	June 20, 2013	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Cary Harbor	Requester:	Yakov Lasko

11.1 Utility Owned Generation (Nuclear)

Question 7

11.1.2. Please refer to PG&E's attachment titled ERRA-2012-PGE-Compliance_DR_DRA_006_Q04Atch02 to data request question 6.1.4 in answering the following DR questions:

11.1.2.6. Referring to page five (5) of the NRC Form 366A, point C.(1):

11.1.2.6.1. Please explain the "mental model" that was used by PG&E to estimate contamination levels due to the environment. Please provide supporting documents and workpapers explaining the existence, validity, applicability, authority, etc. comprising this "mental model."

11.1.2.6.2. Please identify and explain the inadequacies of the "mental model" and why it was inadequate for the purpose to which it was applied.

11.1.2.6.3. Was the contaminated equipment in the Unit 2 MBT area indoors or outdoors?

11.1.2.6.4. To what extent did the design or use of the Unit 2 Emergency Diesel Generators exhaust stacks contributed to the prior bushing failures? Please provide all root-cause and after-incident reports for any previous bushings failures at DCPP.

11.1.2.6.5. Please describe the weakness in planning and executing construction projects that contributed to contamination on the equipment in the Unit 2 MBT area. Did these weaknesses contributed to any prior bushings failures in the past at DCPP?

Answer 7

11.1.2.6.1 The term "mental model" is not a term of art, but rather is a colloquialism used in the RCE and LER. The usage of the word "mental model" refers to the assumptions made by the engineer based on the information known concerning the DCPP environment at the time of design. DCPP does not maintain documents or work papers defining "mental model." Please refer to PG&E's response to Question 11.1.2.6.2 below.

11.1.2.6.2 The discussion in the root cause concerns the perception by engineering that the contamination levels present at the plant were closer to "light" as discussed in the IEEE guidance due to the preponderance of good weather and sunny days experienced at the site. There was a previous study performed in 1968 that measured contamination levels and concluded that the area near the power plant was in a heavy contamination location. The previously installed porcelain insulators (bushings) were not able to meet the recommended creepage distance for this equipment. The DCM S-61B recommended Silicon grease be used to provide margin for the creepage and is an accepted industry practice. The engineering evaluation concluded that the polymer replacement (with silicone embedded in the polymer) would provide comparable performance to silicone grease used on porcelain.

At the time the design was being performed there was no current information that would provide direct guidance regarding measured contamination (Equivalent Salt Deposit Density or ESDD), the engineering mental model of the weather was a factor in the choice of contamination levels. DCPP, as part of the Root Cause Evaluation has created a corrective action (CORR 2) to perform a 2 year study to measure the ESDD in the vicinity of this equipment. The data used during the root cause evaluation was a taken as a "one point in time" consideration to assist in the root cause. Further information is required to accurately determine DCPP specific conditions. The designs going forward will incorporate the appropriate standards and reviews to ensure the contamination buildup is considered.

11.1.2.6.3 Outdoors

11.1.2.6.4 PG&E is unaware of any contribution to bushing failure by the Emergency diesel generators (EDG) exhaust stack. As PG&E explains in its introduction to the Question 1.11.2.1 response, PG&E's submittal of the LER to the NRC was performed within 60 days of the event. At that time, PG&E had not completed its RCE, which concluded that the EDG failure had a low significance role in contributing to the October 11, 2012 event.

EDG are started periodically for testing purposes. Repeated starts of the EDG's contribute to hydrocarbon contamination on the CCVT. There were no previous bushing failures resulting from EDG exhaust stack contamination.[1]

A catastrophic failure occurred on the Unit 2 MBT "C" Phase HV bushing on August 16, 2008. The root cause performed on this event resulted in a presumptive cause which concluded that the cause was either an internal degraded connection or accelerated internal oil loss that resulted in partial discharge and subsequent accelerated degradation. These degraded conditions ultimately resulted in a fault that produced extreme and sudden pressure that caused the bushing to explosively destruct.

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1 See "Diesel Starts" section of Revision 2 of the RCE, pp. 21 and 31 (see document "ERRA-2012-PGE-Compliance_DR_DRA_011-Q01Atch03.docx"), indicating that EDG failure had low significance role in event.

Accordingly, the proximate cause of the 2008 event was not due to external contamination or creepage distance. DCPP does not have any other root cause or after-incident reports for any previous bushings failures at DCPP.[2]

11.1.2.6.5 A weakness in establishing a requirement to implement construction-dust mitigating measures during planning and execution of construction activities was identified as a contributing cause.[3] No history of bushing failures exist in the past at DCPP.

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2 See also, Rev 2 of the RCE, pp. 2, 20, and 31 (addressing 2008 HV bushing failure).

3 *Id.*, p. 36 section 10.2.

[redacted]

EXHIBIT 2.6

PACIFIC GAS AND ELECTRIC COMPANY
2012 Energy Resource Recovery Account Compliance Review
Application 13-02-023
Data Response

PG&E Data Request No.:	DRA_011-11		
PG&E File Name:	ERRA-2012-PGE-Compliance_DR_DRA_011-Q11		
Request Date:	May 29, 2013	Requester DR No.:	011
Date Sent:	June 17, 2013	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Yakov Lasko

11.1 UTILITY OWNED GENERATION (NUCLEAR)

QUESTION 11

11.1.2. Please refer to PG&E's attachment titled ERRA-2012-PGE-Compliance_DR_DRA_006_Q04Atch02 to data request question 6.1.4 in answering the following DR questions:

11.1.2.10. Please provide a list of all the capacity-related costs or their estimates (such as CAISO Capacity Procurement Charges, CAISO Standard Capacity Product Charges, RA replacement capacity costs, etc.) and the relevant dollar amounts that PG&E has incurred as a result of Unit 2 forced outage that occurred on October 11, 2012. Please indicate if the charges were actual charges or PG&E's estimates. Please provide relevant workpapers, invoices, and other documents for these charges.

ANSWER 11

In response to this data request, PG&E provides a list of actual capacity-related costs as Attachment 1 (see Excel file "ERRA-2012-PGE-Compliance_DR_DRA_011-Q11Atch01-CONF.xlsx").

PACIFIC GAS AND ELECTRIC COMPANY
2012 Energy Resource Recovery Account Compliance Review
Application 13-02-023
Data Response

PG&E Data Request No.:	DRA_011-12		
PG&E File Name:	ERRA-2012-PGE-Compliance_DR_DRA_011-Q12		
Request Date:	May 29, 2013	Requester DR No.:	011
Date Sent:	June 17, 2013	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Yakov Lasko

11.1 UTILITY OWNED GENERATION (NUCLEAR)

QUESTION 12

11.1.2. Please refer to PG&E's attachment titled ERRA-2012-PGE-Compliance_DR_DRA_006_Q04Atch02 to data request question 6.1.4 in answering the following DR questions:

11.1.2.11. Has PG&E incurred other miscellaneous market-related charges (that are non-capacity related charges, losses on foregone energy sales, or replacement energy costs) due to October 11, 2012 forced outage? If so, please list those charges (such as real-time imbalance energy charges for Day-Ahead Schedule Deviations, Congestion Revenue Rights Charges, on-site auxiliary load costs, PIRP allocation charges, etc.) and their relevant dollar amounts. Please indicate if the charges were actual charges or PG&E's estimates and provide relevant workpapers, invoices, and other documents for these charges.

ANSWER 12

In response to this data request, PG&E provides a list of actual CAISO charges in Attachment 1 to PG&E's response to Question 11.1.2.10 (see Excel file "ERRA-2012-PGE-Compliance_DR_DRA_011-Q11Atch01-CONF.xlsx").

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

1 [redacted]

2 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

1 [redacted]

2 [redacted]

Chapter 3

Witness: Ravinder Mangat

PG&E'S MANAGEMENT OF UTILITY-OWNED GENERATION – FOSSIL

A. INTRODUCTION

This chapter addresses whether PG&E's management prudently managed its fossil fueled utility owned generation (UOG), with an emphasis on outage avoidance and mitigation, from January 1, 2012 to December 31, 2012 (the Record Period). DRA reviewed PG&E's generation outage information (including the underlying factors for certain outages) to ensure that ratepayers did not suffer any economic losses due to PG&E's unreasonable management of UOG outages.

Standard of Review for UOG Chapter

In D. 02-10-062, the Commission established Standard of Conduct 4 (SOC 4), which provides that: "The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner." The Commission has consistently applied the "reasonable manager" standard to assess whether utilities prudently operated their UOG facilities and to determine whether or not an outage is reasonable. Pursuant to D.09-09-088,[46] the Commission explained that:

> [U]tilities are held to a standard of reasonableness based upon the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act.[47]

As discussed in the SONGS OII (I12-10-013), the utility has ultimate responsibility for collecting incremental "inspection and repair costs" from the manufacturer of components that failed, regardless of the reason for the failure.[48]

[46] D.09-09-088, 37 CPUC2d 488, 499.

[47] *Id.*; *see also* D.10-07-049, p. 13 n. 6.

[48] Division of Ratepayer Advocates Testimony, Regarding SONGS 2 & 3, SCE/SDG&E, December 17, 2012, January 9, 2013 and January 31, 2013 Testimonies.

Ratepayers are not responsible for these charges, and therefore these charges should not be included in the ERRA balancing account. Ratepayers should also not pay for both replacement power and base rates, where outages are caused by equipment failure.[49]

DRA's review focused on whether or not PG&E prudently operated its facilities in an acceptable manner according to the "reasonable manager" standard. This chapter presents DRA's conclusions regarding whether or not PG&E managed its resources in a reasonable manner, and in particular whether outages, or the length of outages, were reasonable or not. In addition, DRA maintains that PG&E is not eligible to claim in ERRA any "inspection and repair costs" due to equipment failure, regardless of the reason for that failure, nor any energy replacement costs owing to this failure.[50]

B. SUMMARY

DRA reviewed outage information from PG&E's [redacted] DRA found that one of the outages at Humboldt Bay Generating Station (HBGS) required further investigation. [redacted]

[49] Evidentiary hearing, I12-10-013, RT, at pp. 991–993 (May 16, 2013).

[50] *Id.* at pp. 991–992.

[redacted]

In connection with this outage at HBGS, DRA recommends a total combined disallowance of $1.7 million, which includes:

- Foregone energy costs of $87,000, and
- Capital and labor costs of $1.61 million.

C. DISCUSSION

1. Overall Approach to Investigating PG&E's Administration of UOG Resources

The following was DRA's approach to reviewing PG&E's testimony on UOG facilities:

- Identify whether there have been any forced outages, or maintenance/planned outages that were significantly longer than originally planned;
- Determine whether any failure of PG&E to act prudently and as a reasonable manager in the operation of this resource led to these outages occurring or lasting longer than they should have done.

In order to achieve this objective, DRA reviewed PG&E's testimony, work papers, and master data response. It was then determined whether a disallowance should be levied upon PG&E, and if so, by how much. Specific components of the review include but are not limited to:

- Forced outages of more than 24 hours in length;
- Maintenance/planned outages that lasted longer than planned.

2. Scope of DRA's Review of Testimony

DRA examined PG&E's three UOG generating stations—Colusa, Humboldt Bay, and Gateway. A detailed description of each of these resources is provided in the least-cost dispatch chapter. Gateway generating station (GGS) did not have any maintenance or forced outages in the Record Period. Colusa GS experienced one maintenance outage and one forced outage in 2012. In contrast, Humboldt Bay GS (HBGS) experienced 25 maintenance outages and two forced outages. HBGS' outage record, in and of itself, merited further investigation. One of the outages at HBGS Unit 5 was [redacted] The remainder of the chapter focuses on this specific outage, and, particularly the circumstances that led to it; further implications of the outage; and the calculation of disallowances derived from PG&E's failure to be a "reasonable manager" and minimize ratepayers cost.

3. Description of Outage at HBGS Unit 5

According to PG&E's Master Data Request response, [redacted] [redacted].[51] [redacted]

a. Original Maintenance Outage in response to ABB Service Bulletin

PG&E's testimony indicated that the original [redacted] was scheduled because "in November 2012, the turbocharger manufacturer, ABB, contacted PG&E about a service news bulletin they issued advising turbocharger owners to inspect nozzle ring bolts and sleeves. Experience with turbochargers at other sites had shown that these bolts may loosen over time." According to PG&E, the work undertaken included an inspection of the nozzle ring bolts and sleeves to "assure that they were not loose." In cases where these bolts and sleeves were found to be loose, the maintenance team either temporarily tightened them or replaced the bolts and sleeves with an improved design.[52]

[redacted]

[51] DRA's Master Data Request, question 14.

[52] PG&E's testimony, p. 5-19, lines 3–19.

b. Prolongation of Original Outage at Unit 5[redacted]

DRA propounded a Data Request 17 (DR 17) to request information about [redacted]. According to PG&E, during the [redacted].[53] [redacted]

[redacted].[54]

To further understand how this damage occurred, DRA organized a conference call with PG&E on July 31, 2013. In preparation for this conference call, PG&E's witness provided (non-confidential) diagrams of the exterior of the HBGS engine exhaust system, shown below as figures 3.1 and 3.2, and one picture of the interior, shown below as figure 3.3. According to PG&E's witness, the component numbered 200 332 (shown in both figures 3.1 and 3.2 in red box) is the exhaust bellows expansion joint, and its function is to support the structure of the exhaust manifold from the extreme conditions created by the flow of heated gas used in each engine.

[53] PG&E's response to Data Request 17 (received July 19, 2013).

[54] *Id.*

Figure 3.1: Humb[redacted]enerating Station ([redacted]
(from PG&E's e[redacted]1st July, 2013)

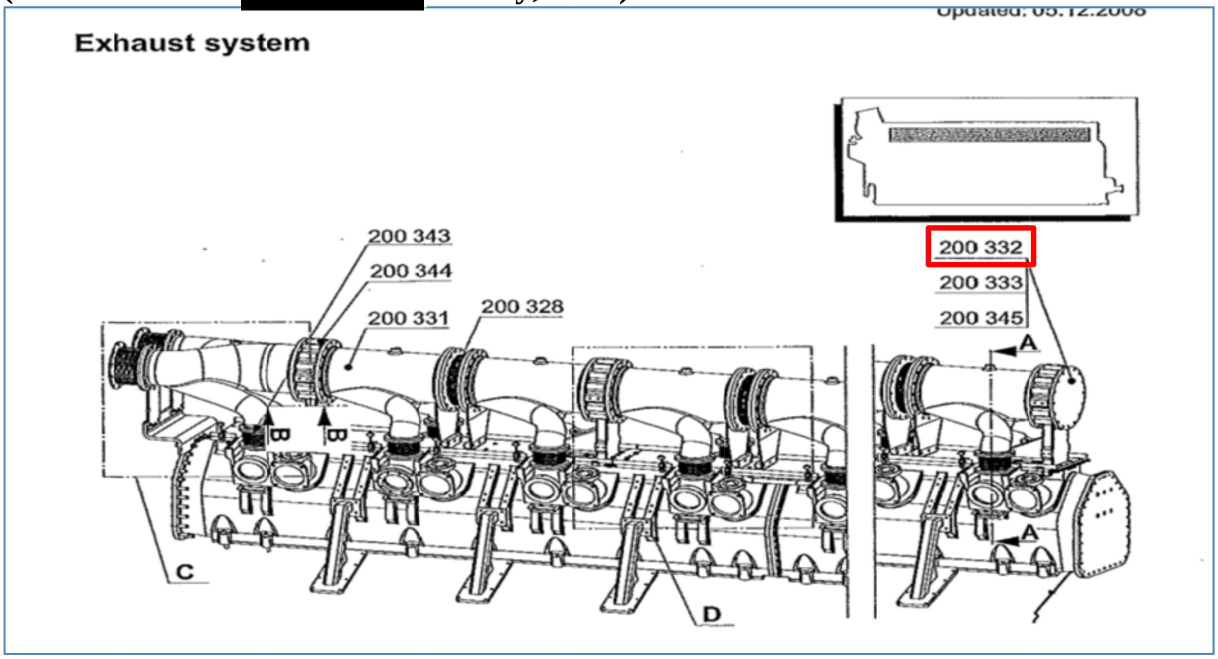
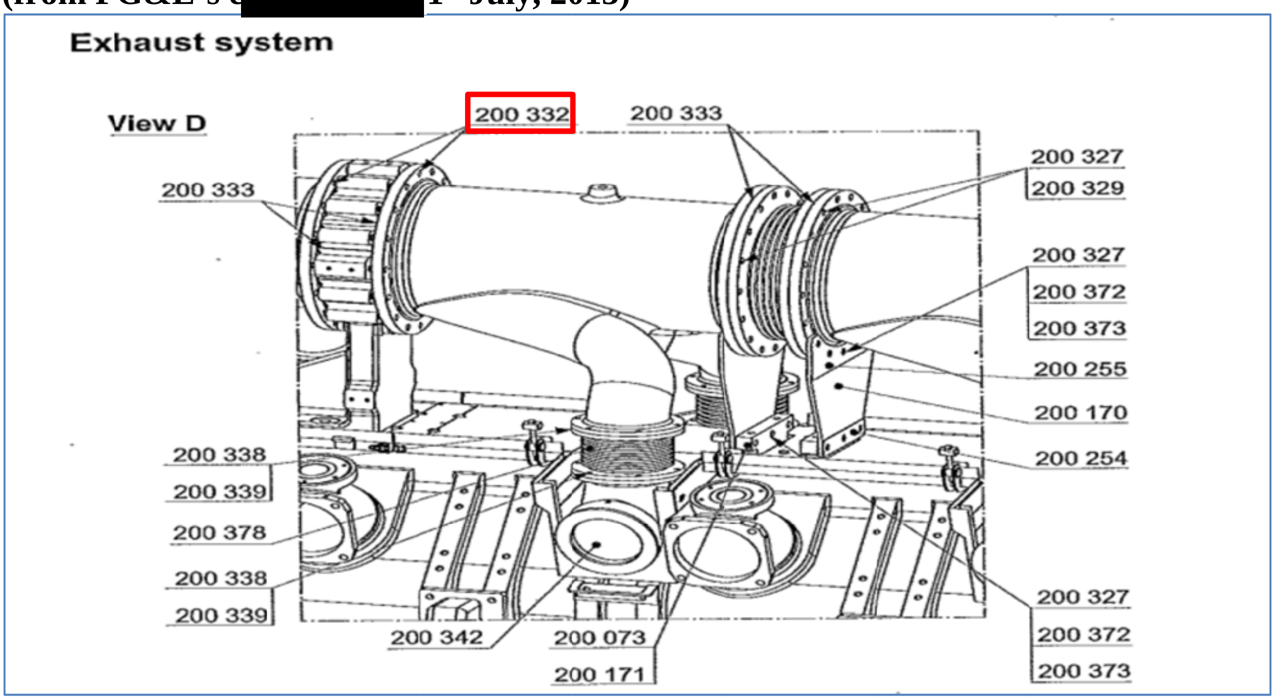


Figure 3.2: Expa[redacted]n of HBGS Engine [redacted]
(from PG&E's e[redacted]1st July, 2013)



[redacted]

[redacted][55] Figure 3 depicts an example where the [redacted]. According to PG&E, [redacted].[56] The turbocharger is located close to the exhaust gas manifold.

Figure 3.3: [redacted])
(from PG&E's email dated 31st July, 2013)

[55] PG&E's response to DRA's Data Request 21, 21.2.1.7 (received Aug. 9, 2013).

[56] PG&E's response to Data Request 17 (received July 19, 2013).

c. Root Cause Analysis of the [redacted]

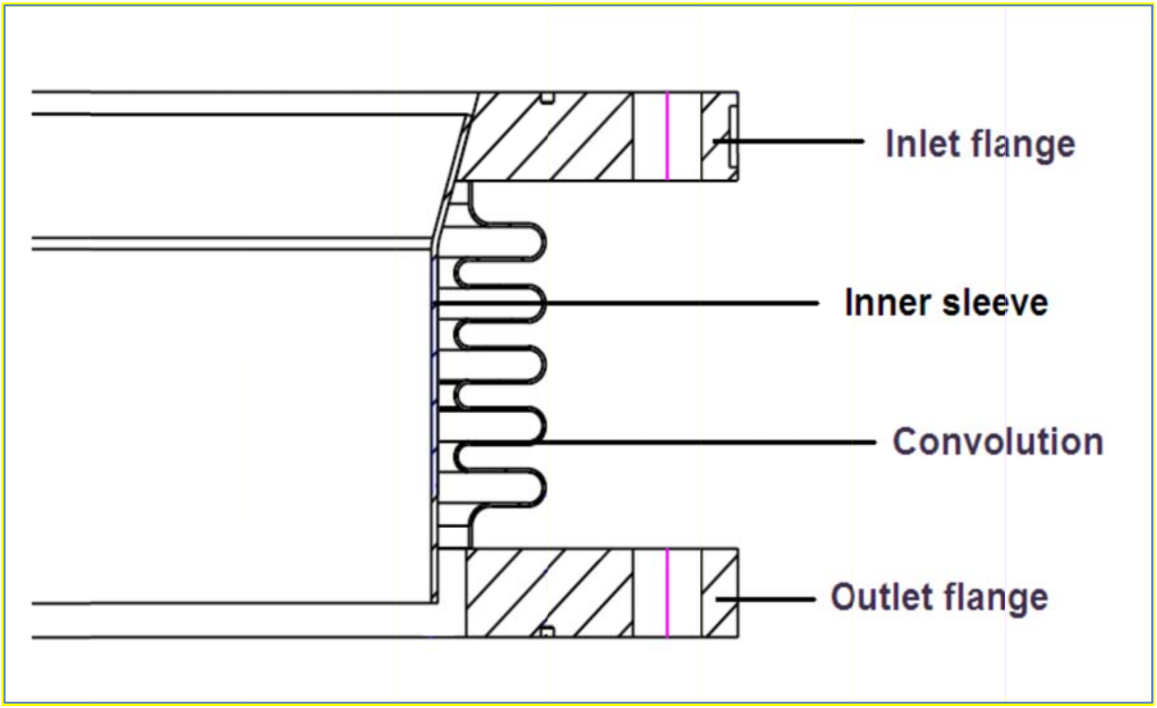
PG&E ordered an investigation report into the cause of the [redacted] According to PG&E, Wartsila was selected to conduct the investigation because it is [redacted].[57] There was [redacted]

According to Wartsila's investigation report, [redacted]. They found that the initiation point of the [redacted] Wartsila established that [redacted]

[57] PG&E's response to Data Request 17, question 6 (received July 19, 2013).

[58] [redacted]

[redacted][59]



According to the original scope, Wartsila's report was required to include recommendations. However, the final report contains no such recommendations.[60] PG&E did not explain the reasons why the report was accepted without these recommendations and/or whether PG&E required Wartsila to complete its report by including recommendations.

In summary, based on Wartsila's report, DRA's assessment is that it appears [redacted]).

[59] *Id.*

[60] PG&E's data response to Data Request 21, question 21.2.1.3. (received Aug. 9, 2013).

d. Assessment of PG&E’s Role in the Outage at HBGS Unit 5

Although DRA accepts that [redacted], DRA found that PG&E failed to show that it prudently conducted maintenance activities on the [redacted]. According to the maintenance schedule that [redacted], [redacted].[61] [redacted]

DRA propounded Data Request 21 (DR 21), requesting evidence of any inspections or maintenance activities relating to the [redacted] of the plant during the Record Period for all units. PG&E reported that the only activities conducted during the Record Period were those advanced in response to [redacted][62] Based on this response, DRA concluded that PG&E failed to implement [redacted]

Based on the set of activities described in the maintenance schedule, PG&E should have discovered evidence of the damage, [redacted], at an

[61] PG&E’s response to DRA’s Data Request 21, questions 21.2.5.1 & 21.2.5.2. (received Aug. 9, 2013).

[62] *Id.*, questions 21.2.5.3.

earlier stage. In particular, [redacted] In addition, PG&E failed to notice a difference in the [redacted]. The significant difference in [redacted] should have been noticeable. In summary, had PG&E undertook assiduous and vigilant maintenance activities complying with the required maintenenance schedule, [redacted] could have been prevented.

Moreover, while it appears that the [redacted]. This is further evidence of PG&E's failure to prudently manage its UOGs as a reasonable manager, and DRA recommends that, in the future, PG&E uses [redacted] to conduct a root cause analysis of this type.

Further, PG&E has not demonstrated that it has used the judgment of a reasonable manager in selecting the company to manufacture and install its engine components at its UOGs. PG&E noted that it entered into an Engineering, Procurement and Construction (EPC) contract with Wartsila for HBGS, based on PG&E's 2004 Long-Term Request for Offers (RFO) pursuant to D.06-11-048.[63] However, PG&E's response to DR 21.2.7, failed to provide any "proof that the installing company had a track record of reliable installations equal to or higher than industry standards." Similarly, in response to DR

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[63] PG&E's Response to DR 21.2.7 (received Aug. 9, 2013).

21.2.6., PG&E failed to provide any "proof from the supplier of the inner liner that their products are, as a minimum, manufactured to industry standards." This raises a concern and by not submitting this information to DRA on request, it suggests that PG&E has not acted prudently in this regard.

Finally, as part of their contract negotiation with Wartsila, PG&E should have required that the vendor be responsible for foregone energy costs (also known as "power replacement costs") in the event of any installation or manufacturing defects. As discussed in detail in this section, [redacted]. These outages led to negative effects, particularly in areas like Humboldt, which is within a locally constrained transmission area and the local community is relatively dependent on this facility.[64] Also, as referred to in the introduction section, PG&E has a responsibility to ensure that ratepayers do not bear the costs of inspections and repairs.[65] In this situation the burden of collecting these costs, including any power replacement costs is placed on the utility.

DRA propounded DR 21, asking PG&E whether Wartsila would reimburse net energy replacement costs due to the outages at Unit 5, and related to actions taken to correct potential or actual damage to the other units. [redacted] DRA concluded that PG&E failed to act as a reasonable manager by [redacted]. As a result, DRA recommends disallowance of energy replacement costs derived from the

[64] 2013 Local Capacity Technical Analysis, Final Report And Study Results, CAISO (Apr. 30, 2012).

[65] Division of Ratepayer Advocates Testimony, Regarding SONGS 2 & 3, SCE/SDG&E, December 17, 2012, January 9, 2013 and January 31, 2013 Testimonies.

[redacted] in response to ABB's service news bulletin.

e. Disallowance Calculations

Based on the damage described to [redacted], the calculation of disallowances can be divided into two areas

1) capital and labor costs, and
2) foregone energy (also known as net energy replacement) costs.

Capital and Labor costs

In response to ABB's service bulletin, PG&E incurred capital and labor costs from [redacted].

PG&E conducted inspections and/or repairs to [redacted] DRA requested an estimate of these costs in DR 21.[66] PG&E's response did not provide an estimate of this specific cost, but rolled it together with repairs stemming from the [redacted]

In assessing the total costs of the damage [redacted], these costs can be subdivided into a further three areas:

[redacted]

3) [redacted];

[66] DRA's Data Request 21, question 21.2.10.1.

[67] Identified by PG&E's witness at conference call with DRA, 31st July 2013.

DRA requested PG&E to estimate the cost for these three items, 1) through 3), to assess the full labor and capital costs of these incidents.[68] In its response, PG&E noted that "[redacted]"[69] [redacted]

PG&E's response to DRA's DR 21.2.5, also noted that, in addition to [redacted] Therefore, the final cost category under capital and labor also includes the cost of repairing [redacted].

To estimate the potential cost of these repairs, DRA noted that the cost of repairing the [redacted]

In total, DRA's total capital and labor disallowance [redacted] is $1.61 million. The bulk of these costs are from [redacted]. This amount also includes the labor and capital costs of [redacted]

[68] DRA's Data Request 21, questions 21.2.4 & 21.2.11

[69] PG&E's response to DRA's Data Request 21, questions 21.2.13

[redacted]

Table 3.1: total disallowance based on labor and capital costs

Cost item	Cost ($m)
[redacted]	[redacted]
[redacted]	
[redacted]	
[redacted]	
[redacted]	[redacted]
Total Cost	$1.61m

Foregone Energy (or Energy Replacement) Costs

DRA believes that PG&E should negotiate contracts in which foregone energy costs are covered by the supplier or installer of components in the event that any kind of defect occurs that materially affects the operation of the resource. Similarly, if PG&E is at fault during the contracting, installation, or maintenance process, PG&E should bear all necessary foregone energy costs.

In consideration of the foregone energy costs relating to these outages, DRA uses the following formula:

A * (P – F) = Disallowance

Where,

A = the average total net award in MWs that HBGS would have reasonably been able to receive for each hour during the duration of the outage. This, in turn is dependent on the average total net maximum capacity (NMC) from the beginning to the end of an outage multiplied by the probability that a resource will be dispatched during this timeframe (derived from the capacity factor).[70]

H = the duration of the forced outage in hours from the beginning of the subject outage until the end.

P = the average locational marginal price (LMP) of energy per MWh for the subject outage at the price node at which the resource's energy price is sold. DRA uses the average price for the Record Period as a proxy.

F = the average unit fuel costs for the resource. DRA uses the average price for the record year.

[redacted]

Accordingly, DRA's estimate of the foregone energy costs will be equivalent to the product of **A * (P – F).**

1) In the case of the [redacted], the total disallowance is calculated as follows:

[redacted] = **$52,277**.

Maintenance [redacted]

In the case of [redacted], foregone energy costs are calculated in relation to outages caused by:

[redacted]

[70] PG&E's response to Data Request 17, question 1 (received July 17, 2013) (Service hours/available hours).

[redacted] (numerals (2) and (3), above), combined, led to an outage of [redacted] In relation to this [redacted]—, DRA requested the duration of these outages in DRA DR 21.2.4, but as yet no response has been received from PG&E. Based on internal engineering knowledge, DRA uses a proxy figure of 6 hours per outage (i.e. seven units * six hours = 42 hours of outages), until a more detailed response is received from PG&E.

[redacted]

(2) & (3) combined disallowance ([redacted]

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[71] Identified by PG&E's witness at conference call with DRA (July 31, 2013).

[72] DRA's Master Data Request, question 14. This footnote also applies to the disallowance calculation for (4) and (5).

[73] PG&E's response to DR 17 (received July 19, 2013) (formula used: service hours/available

(continued on next page)

[redacted]

In summary, total disallowance costs as a result of foregone energy costs to serve ratepayers while [redacted] are equivalent to $87,000.

(continued from previous page)
hours). This footnote also applies to the disallowance calculation for (4) and (5).

[74] *Id.* (quoted NMC of unit). This footnote also applies to the disallowance calculation for (4) and (5).

[75] LMP prices are from CAISO and fuel prices are taken from the PG&E's LCD workpapers – Volume 2. This footnote also applies to the disallowance calculation for (4) and (5).

Table 3.2: total disallowance based on foregone energy costs

Cost category	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	**$86,900.00**

Chapter 4

Witnesses: Yakov Lasko and Colin Rizzo

QUALIFYING FACILITY CONTRACT ADMINISTRATION

A. SUMMARY

(by Yakov Lasko and Colin Rizzo)

DRA recommends two disallowances and a corrective action with regard to PG&E's administration of Qualifying Facility (QF) contracts. DRA concluded that PG&E did not act as a reasonable manager by prudently administering the Amedee Geothermal Venture 1 (AGV1) and the Wendel Energy Operations 1 (WEO1) contract. DRA recommends a disallowance of $20,062 for the AGV1 contract and a disallowance of $106,109.30 for the WEO1 contract. DRA witness Yakov Lasko's testimony addresses the calculation of these disallowance amounts.

In addition, DRA recommends that PG&E adopt oversight procedures to ensure that its future contracts are prudently administered. PG&E's rate recovery of $[redacted] derived from the contract with the University of California, San Francisco campus (UCSF), should be approved subject to PG&E's adoption of the aforementioned corrective action, which will prevent future adverse impact for ratepayers.

B. BACKGROUND

(by Colin Rizzo)

1. Prudent Administration of Contracts Pursuant to Standard of Conduct 4

The Commission determined that pursuant to Standard of Conduct 4 (SOC4), the utilities "shall prudently administer all contract and generation resources and dispatch the energy in a least cost-manner"[76] to mitigate ratepayer impact by "operating their resources in a manner that produces the lowest possible cost for customers."[77] The

[76] D.05-01-054 at p. 13.

[77] D.05-01-054 at pp. 13–14.

utility's prudent contract administration includes enforcing the terms and conditions of contracts to ensure that resources are dispatched when it is most economical to do so.[78] Simply put, in administering contracts, the utilities must "dispose of economic long power and purchase economic short power in a manner that minimizes ratepayer cost."[79]

In addition, in the ERRA compliance proceedings the "outcome or standard for review has been predetermined – that is the lowest cost [for ratepayers]."[80] In other words, unlike in a traditional reasonableness review, the Commission will not look at a range of reasonable outcomes that a reasonable manager would have achieved based on what he or she knew or should have known at the time that the decisions regarding the administration of its contracts were made, but at whether the utility's contract administration "resulted in the most cost-effective mix of total resources, thereby minimizing the cost of delivering electric services."[81] The utility bears the burden of proving that it has administered its contracts to produce the lowest possible cost for ratepayers.[82]

C. DISCUSSION

(by Colin Rizzo)

1. DRA Recommends a Corrective Action Based on PG&E's Failure to Prudently Administer the Qualifying Facility Contact with the University of California, San Francisco (UCSF)

As indicated above, PG&E has a duty to prudently administer its contracts in a fashion that minimizes ratepayer costs.[83] DRA found that PG&E did not prudently administer its QF contract with UCSF because PG&E failed to comply with the contract

[78] D.02-12-074 at p. 54 (quoting language that the Commission includes in the confidential appendix of the utilities' long-term procurement plans).

[79] *Id.*

[80] *See* D.05-01-054 at p. 14.

[81] *Id.*

[82] D.02-12-074 at p. 54.

[83] D.02-12-074 at p. 54.

terms.[84] However, since ratepayers were not adversely impacted, DRA does not recommend a disallowance with regard to this contract. Instead, DRA recommends that PG&E adopt corrective action procedures for the administration of future contracts to prevent ratepayer exposure to rate increases and to ensure reliable service and continuous service.

In its testimony, [redacted][85] [redacted].[86] [redacted].[87] [redacted][88] [redacted].[89] [redacted].[90] [redacted]

DRA is not recommending a disallowance on this contract because [redacted],[91] [redacted] However, DRA found that PG&E failed to prudently administer its QF contract with UCSF by [redacted]

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[84] *See* PG&E Testimony, Chapter 10 at p. 10-34.

[85] *Id.*

[86] *Id.*

[87] *Id.*

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] *See* PG&E Testimony, Chapter 10 at p. 34.

[redacted]. This failure to comply with the terms of its QF contract with UCSF could have exposed PG&E's ratepayers to higher rates [redacted]. To prevent similar situations in future contracts, DRA recommends the following corrective actions.

Corrective Actions:

PG&E should adopt contract compliance monitoring and oversight procedures to ensure that PG&E's future contracts are prudently administered. Compliance audits should occur at least every three years and should focus on whether PG&E is complying with its contractual obligations, prudently administering its contracts, and dispatching energy at the lowest possible cost for ratepayers.

During its contract audits, PG&E should prepare a corrective action report where it: (1) identifies the issue or problem; (2) establishes a root cause evaluation; (3) prepares action steps; (4) establishes improvement benchmarks and timeframes; and (5) PG&E management certifies the contents of the corrective action report. When identifying issues or problems, PG&E reviewers should discuss whether PG&E is complying with its contractual obligations and dispatching energy at the lowest possible cost for ratepayers. If PG&E is not in such compliance, then PG&E should prepare a Root Cause Evaluation. The primary aim of a Root Cause Evaluation will be to identify the factors that resulted in the nature, the magnitude, the cause, and the timing of the incident that led to non-compliance with contract terms so that recurrence of similar outcomes is prevented at lowest cost and in the simplest way. To be effective, PG&E reviewers should establish a sequence of events or timeline to understand the relationships between the causal factors, root causes, and the defined problem or event to prevent its recurrence.

After PG&E prepares the Root Cause Evaluation, it should establish Action Steps. The Action Steps document will stipulate what PG&E contract management will do to meet all applicable contract requirements and establish a consistent compliance process. Furthermore, PG&E will develop a training module explaining the consequences of non-compliance with contract terms, monitor compliance, and provide feedback on performance. Following the Action Steps, PG&E should set improvement benchmarks and a timeframe where it sets a schedule for achieving compliance with the contract terms. This should be certified in writing by PG&E management.

2. DRA Recommends Two Disallowances Derived from PG&E's Failure to Prudently Administer its Amedee Geothermal Venture 1 and the Wendel Energy Operations 1, LLC contract

DRA found that PG&E did not prudently administer its contracts with Amedee Geothermal Venture 1 (Amedee) and Wendel Energy Operations 1, LLC (Wendel). [redacted][92] [redacted][93] However, according to PG&E's data response to DRA's data request, [redacted][94] [redacted]

PG&E negotiated settlement agreements with [redacted]

[92] *See* Exhibit 4.1: Data Request ERRA-2012-PG&E-Compliance_DR_DRA_007-Q08.

[93] *See* PG&E Testimony, Chapter 10 at p. 34.

[94] Exhibit 4.1: Data Request ERRA-2012-PG&E-Compliance_DR_DRA_007-Q08.

[95] PG&E Testimony, Chapter 10 at p. 34.

[96] PG&E Testimony, Chapter 10 at p. 34.

[redacted].[97] DRA found that had PG&E prudently administered its contracts with Amedee and Wendel, [redacted]. In other words, [redacted] As a result, ratepayers will have to bear the cost of [redacted], in violation of SOC 4, which requires PG&E to minimize ratepayer cost in the administration of its contracts. PG&E failed to prove that its conduct with regard to the administration of the Amedee and Wendel contracts produced the lowest possible cost for ratepayers, and thus DRA recommends a disallowance of the [redacted]

D. DISALLOWANCES

(by Yakov Lasko)

1. Introduction

In this part of the testimony, DRA presents its methodology and calculations to determine the appropriate disallowance amount that should be applied to PG&E's failure to prudently administer the Amedee Geothermal Venture 1 (Amedee) and Wendel

[97] PG&E Testimony, Chapter 10 at p. 34.

Energy Operations 1 (Wendel) contracts, as recommended in DRA witness Colin Rizzo's part of the testimony.

2. Summary of Recommendations

As discussed in Mr. Rizzo's testimony, DRA found that PG&E did not prudently administer the Amedee and Wendel contracts.[98] Accordingly, DRA recommends disallowances in the amounts of $20,062 and $106,109 derived from the imprudent administration of the Amedee and Wendel contracts, respectively, for a total disallowance recommendation of $126,171.

3. Disallowance Recommendation Regarding the Amedee Geothermal Venture 1 (PG&E Log No. 10G012EO1) and the Wendel Energy Operations 1, LLC (PG&E Log No. 10G011) Contracts

a. DRA's Disallowance Recommendations Must Be Discounted at Present Value.

According to the time value of money principle, a dollar today is more valuable than a dollar tomorrow for three reasons:

- Individuals prefer present consumption to future consumption. Accordingly, people must receive an incentive to defer consumption to a later date.
- Inflation erodes the value of currency so that, all else equal, a dollar today will purchase more than a dollar in the future.
- The uncertainty or risk in collecting a dollar in the future, that causes the value of that dollar to be less (*i.e.*, a bird in the hand is worth two in the bush).[99]

Future cash flow payments must be adjusted by applying an appropriate discount rate that properly accounts for the time value of money.[100] A discount rate is a rate that estimates the tradeoff between present and future cash, based on the three reasons listed

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[98] *See* DRA's witness C. Rizzo's testimony pp. 4-1 to 4-5.

[99] Aswath Damodaran, p. 2 http://pages.stern.nyu.edu/~adamodar/pdfiles/cf2E/tools.pdf (last visited Aug. 3, 2013). *See* Exhibit 4.2.

[100] *Id.* at p. 3.

above.[101] The use of a higher discount rate will lead to a lower present value of cash flows to be received in the future. Conversely, a lower discount rate will lead to a higher present value of cash flows to be received in the future.[102] Finally, cash flows that have already been received need not be discounted because the appropriate discount rate to be applied is 0% and the discount factor is one (1).[103]

Therefore, the cash flows that PG&E will receive in the future [redacted] pursuant to the settlement agreements with Amedee and Wendel must be discounted by an appropriate discount rate that reflects the equivalent present value of those promised future cash flows. Any payment that PG&E has received must not be discounted because it is already equal to its present value.

b. DRA Recommends a $20,062 Disallowance Derived from PG&E's Failure to Prudently Administer the Contract with Amedee

PG&E reported to have overpaid Amedee by [redacted] [redacted] Pursuant to October 3, 2012 settlement agreement, Amedee agreed to repay [redacted]. On March 22, 2013, DRA propounded a Data Request (DR) asking PG&E to clarify whether the [redacted] amount would be paid in a lump sum or by installments and, if the latter, to provide an approximate net present value (NPV) of [redacted].[105] PG&E's replied that [redacted] [redacted]."[106] Based on PG&E's response, DRA treated the [redacted], which needs not be discounted because it is equal to its present value.

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[101] *Id.*

[102] *Id.*

[103] The formula for these cash flows is 1/(1+r)t, where t is time and r is discount rate. Discounting the cash flow that has been received will not change its value because the discount factor is one (X * 1 = X).

[104] PG&E Testimony, Chapter 10 at p. 10-33.

[105] *See* Exhibit 4.3: Data Request, DRA_002-01 Question 2.3.1.4.1.

[106] *See* Exhibit 4.3: Data Request, DRA_002-01 Question 2.3.1 and MDR001-Q048_Atch02-CONF.

Therefore, DRA recommends the Commission to disallow the difference between [redacted] which is equivalent to $20,062.

c. DRA Recommends a $106,109 Disallowance Derived from PG&E's Failure to Prudently Administer the Wendel Contract

PG&E also reported to have overpaid Wendel [redacted] Pursuant to October 1, 2012 settlement agreement, Wendel agreed to [redacted].[107] [redacted] it is necessary to discount [redacted] by an appropriate discount rate to determine the present value of these cash flows.

On March 22, 2013, DRA propounded a Data Request asking [redacted], [redacted].[108] PG&E's response stated that [redacted].”[109] PG&E also provided DRA with an Excel file attachment showing its NPV calculations.[110] PG&E's calculations included two assumptions: [redacted].[111]

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[107] PG&E's Prepared Testimony, p. 10-34, lines 4-8.

[108] *See* Exhibit 4.4: Data Request, DRA_002-02 Question 2.3.2.4.

[109] *See id.*

[110] *See* Exhibit 4.4: ERRA-2012-PGE-Compliance_DR_DRA_002-Q02Atch02-CONF.xls

[111] *See* Exhibit 4.4: Data Request, DRA_002-02 Question 2.3.2.

In a subsequent Data Request, DRA sought further information on PG&E's use of [redacted] percent discount rate. PG&E' indicated that [redacted] and that [redacted][112] DRA found that the [redacted] is the appropriate discount rate because it was widely used by [redacted] Subsequently, DRA modified PG&E's calculations by increasing the monthly discount factor to [redacted] DRA found that, applying the [redacted] the cumulative NPV of the [redacted].[113] Therefore, DRA recommends that the Commission disallow the difference between [redacted] and [redacted], which is equivalent to $106,109.30.

E. CONCLUSIONS AND RECOMMENDATIONS

(by Yakov Lasko and Colin Rizzo)

DRA recommends that PG&E adopt corrective actions to ensure that PG&E complies with its contractual obligations, prudently administers its contracts, and dispatches energy at the lowest possible cost for ratepayers.

DRA recommends two disallowances because PG&E did not prudently administered Amedee and Wendel contracts. DRA recommends a $20,062 disallowance derived from the Amedee contract and a $106,109.30 disallowance derived from the Wendel contract. DRA recommends a total disallowance of $126,171.30.

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[112] *See* Exhibit 4.5: Data Request, DRA_010-02 Question 10.5.1.2.3 and 10.5.1.2.4

[113] *See* Exhibit 4.6: DRA's NPV Calculation for WEO1.

Chapter 4 Exhibit Index	
Exhibit 4.1	Data Request DR_DRA_007-Q08
Exhibit 4.2	Aswath Damodaran. http://pages.stern.nyu.edu/~adamodar/pdfiles/cf2E/tools.pdf (Aug. 3, 2013)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

EXHIBIT 4.1

PACIFIC GAS AND ELECTRIC COMPANY
2012 Energy Resource Recovery Account Compliance Review
Application 13-02-023
Data Response

PG&E Data Request No.:	DRA_007-08		
PG&E File Name:	ERRA-2012-PGE-Compliance_DR_DRA_007-Q08		
Request Date:	May 10, 2013	Requester DR No.:	007
Date Sent:	May 21, 2013	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Candice Chan	Requester:	Colin Rizzo

7.1 QF CONTRACTS IN TABLE 10-22

QUESTION 8

7.5.5. For Log Number 10G012EO1 and Log Number 10G011, discuss the following:

7.5.5.1. Please describe in detail why, despite being given notice, PG&E failed to adjust the meter.

7.5.5.2. Please provide the Corrective Action Report that discusses the subsequent remedial measures taken to mitigate further damages.

7.5.5.3. Section A-3.6 and Section A-5 of both agreements, stipulate the procedure for the adjustment of payments.

7.5.5.3.1. Please discuss why these procedures were not followed.

7.5.5.3.2. Please discuss the outcome that would have resulted had the procedures been followed.

7.5.5.4. For Log Number 10G011, please discuss the following:

7.5.5.4.1. What is PG&E's current return on equity?

7.5.5.4.2. What is PG&E's current weighted average cost of capital (WACC)?

7.5.5.4.3. What discount rate does PG&E typically apply when computing future value calculations?

5.5.4.3.1. Is the discount rate based on PG&E's WACC for all of the projects across the board or the riskiness of individual projects?

5.5.4.3.2. If the discount rate is based on WACC, please include any modifications or basis point adjustments, if any, and an explanation of the methodology and reasons for these modifications and basis point adjustments to PG&E's WACC as it applies to individual projects and specifically, for Log Number 10G011

7.5.5.4.4. What discount rate has PG&E applied to Wendel Energy Operations NPV calculations in PG&E's Data Request #2 responses to DRA in file ERRA-2012-PGE-Compliance_DR_DRA_002_Q02Atch02-CONF? Please justify the discount rate used vis-à-vis responses to questions 7.5.5.4.1, 7.5.5.4.2, and 7.5.5.4.3.

ANSWER 8

7.5.5.1. PG&E field personnel were given notice that the Lassen Municipal Utility District (LMUD) and the Western Area Power Authority (WAPA) would be downgrading the line voltage. However, this information was not passed on to the QF Settlements personnel and thus the PG&E meter constant was not changed at the time of this voltage change. Once QF Settlements became aware of the issue in 2012, it was investigated and corrected.

7.5.5.2. PG&E does not have a Corrective Action Report. However, PG&E has taken the corrective action identified in PG&E's response to DRA's March 21, 2013 Data Request (see responses to Questions 2.3.1 and 2.3.2 provided on April 5, 2013).

7.5.5.3.

7.5.5.3.1. Although the meter data was incorrect from the time in 2009 that LMUD changed the voltage of the line, the QF Settlements personnel who calculate monthly payments to Wendel and Amedee did not know that the meter data was incorrect until 2012. Therefore, PG&E could not request payment within 30 days of notification as required by the provisions cited by DRA. As soon as it was known that the meter constants were incorrect, QF Settlements requested that the constants be corrected, generated correct meter data, and calculated the amounts that PG&E had overpaid these two counterparties. PG&E representatives promptly contacted the counterparties to discuss reimbursement of the overpayments.

7.5.5.3.2. Please see response 7.5.5.3.1 above. QF Settlements acted immediately upon discovery of the meter data errors.

7.5.5.4. PG&E's relationship with Wendel Energy is a commercial relationship between counterparties to a long term power contract: Wendel Energy is the Seller and PG&E the Buyer. PG&E's customers receive the benefits of the energy and the capacity, and the costs associated with the energy and capacity are then passed through to PG&E's customers via the ERRA balancing account. Similar to the response to Question 7.5.4, PG&E does not have an ownership interest in Wendel Energy Operations (Log Number 10G011), and therefore PG&E's current return on equity and weighted average cost of capital are not applicable to the Wendel Energy facility. PG&E does not finance the assets associated with Wendel through equity or debt, nor does PG&E receive any profit or return from the PPA or the facility. Therefore, PG&E's

return on equity, which measures the rate of return on the shareholders' equity of common stock, is not relevant to Wendel Energy.[1]

7.5.5.4.1 to 7.5.5.4.3 See response to 7.5.5.4

7.5.5.4.4 PG&E applied a 7.0% discount rate to Wendel Energy Operations' NPV calculations. This discount rate is a PG&E standard used for internal analysis, and is based on the after-tax weighted average cost of capital. *See* PG&E's response to 7.5.5.4 above with regard to a comparison of discount rates.

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1 Each year, the Commission adopts a rate of return to ensure that the California investor owned utilities can attract capital at reasonable rates and provide a fair return to shareholders. In December 2012, the Commission determined that PG&E's authorized test year 2013 return on equity and return on rate base should be 10.40 percent, which is reasonable when compared to the 10.36 percent average ROEs for U.S. electric utilities in the first six months of 2012 (*see* D.12-12-034, at 43-44).

EXHIBIT 4.2

Intuition Behind Present Value

- There are three reasons why a dollar tomorrow is worth less than a dollar today
  - Individuals prefer present consumption to future consumption. To induce people to give up present consumption you have to offer them more in the future.
  - When there is monetary inflation, the value of currency decreases over time. The greater the inflation, the greater the difference in value between a dollar today and a dollar tomorrow.
  - If there is any uncertainty (risk) associated with the cash flow in the future, the less that cash flow will be valued.
- Other things remaining equal, the value of cash flows in future time periods will decrease as
  - the preference for current consumption increases.
  - expected inflation increases.
  - the uncertainty in the cash flow increases.

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Discounting and Compounding

- The mechanism for factoring in these elements is the discount rate.
- **Discount Rate:** The discount rate is a rate at which present and future cash flows are traded off. It incorporates -
  - (1) Preference for current consumption (Greater ....Higher Discount Rate)
  - (2) expected inflation (Higher inflation .... Higher Discount Rate)
  - (3) the uncertainty in the future cash flows (Higher Risk....Higher Discount Rate)
- A higher discount rate will lead to a lower value for cash flows in the future.
- The discount rate is also an opportunity cost, since it captures the returns that an individual would have made on the next best opportunity.
- Discounting future cash flows converts them into cash flows in present value dollars. Just a discounting converts future cash flows into present cash flows,
- Compounding converts present cash flows into future cash flows.

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Chapter 5

Witness: Ravinder Mangat

LEAST-COST DISPATCH

A. INTRODUCTION

DRA has reviewed and analyzed PG&E's least-cost dispatch testimony for the period from January 1 to December 31, 2012 (Record Period), responses to data requests, and meet and confer notes. DRA also visited PG&E's headquarters to obtain a better understanding of their energy dispatch operations. In D.02-10-062, the Commission sets forth the standards of conduct by which the utilities must administer their portfolios of generation and contract resources. Specifically, standard of conduct 4 (SOC 4) states: "the utilities shall prudently administer all contracts and generation resources and dispatch energy in a least-cost manner."[114] A more detailed description of the standard of review for least cost dispatch is contained in the background section C.

The following testimony provides a summary of recommendations in Section B, a brief background on least-cost dispatch in Section C, discussion and analysis in Section D, and recommendations and conclusions in Section E.

B. SUMMARY

DRA examined PG&E's filing to determine whether PG&E had met their least cost obligations arising from SOC 4. This review of PG&E's testimony, master data responses and work papers, reveals that PG&E did not include a performance evaluation or other type of quantitative analysis that demonstrated PG&E's effectiveness in achieving the least-cost dispatch standard in the record year. It is not possible to conclude that PG&E has met the LCD standard without reviewing this type of analysis.

Given the voluminous amounts of data included in PG&E's filing related to their dispatch activities, DRA's analysis was necessarily limited, and focused on reviewing a sample of the energy bids submitted by PG&E's dispatchable fossil fueled resources to

[114] D.02-10-062, p. 52 and Conclusion of Law 11, p. 74.

CAISO in the day-ahead market. Based on this analysis, in general, PG&E submitted its bids in a cost effective manner, although a number of procedural issues were discovered that PG&E should address in order to ensure that errors in calculating these energy bids are minimized.

DRA recommends corrective action with regard to PG&E's LCD procedures to resolve a significant number of occurrences where PG&E has submitted incorrect bids (*i.e*. bids that are not at incremental cost) into the CAISO market from their [redacted] PG&E acknowledged that these incorrect calculations were due to a number of reasons, including software malfunctions and human errors.

C. DRA RECOMMENDATIONS

DRA recommends that PG&E provides a performance evaluation, comparison tool, or other quantitative analysis that demonstrates their effectiveness in achieving the least-cost dispatch standard.

In addition, DRA identified a significant number of occurrences where PG&E submitted incorrect bids (*i.e.* not at incremental cost) into the California Independent System Operator (CAISO) market from [redacted]. DRA recommends that the Commission order PG&E to:

[redacted]

[115] PG&E's response to Data Request 10, question 3 (received June 7, 2013).

[redacted][116] [redacted]

[redacted] — [redacted] — [redacted]

In relation to recommendations (1) – (4) DRA requires that PG&E present a compliance filing 30 days subsequent to the final decision in this proceeding, to (1) demonstrate what progress has been made in identifying a comprehensive solution to

[116] *Id.*

[117] [redacted]

[118] PG&E's response to Data Request 10, question 4 (received June 7, 2013).

[119] *Id.*

these [redacted], and (2) setting out a timeline stating when the solution will be finalized and implemented.

D. BACKGROUND

1. The Commission's Least-Cost Dispatch Standard

As indicated above, SOC 4 requires utilities to dispatch energy in a least-cost manner.[120] The Commission elaborated on the definition of SOC 4 in D.02-12-074 by indicating that "least-cost dispatch" includes the purchase and sale of energy to achieve the most cost-effective mix of resources and minimize cost to ratepayers. Specifically, D.02-12-074 placed the following explanation of SOC 4 in the utilities' approved procurement plans (thereby representing the "upfront standard" under Assembly Bill (AB) 57 regarding prudent contract administration and the daily dispatch of energy):

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. 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.[121]

This quote from D.02-12-074 contains the appropriate standard review of least-cost dispatch that the Commission applies in ERRA compliance proceedings.

2. Least-Cost Dispatch in the CAISO Market

The role of the utilities in the CAISO market is to schedule and/or bid resources in a manner to optimize resources to meet the Commission's least-cost mandate. After each utility has submitted bids for their resources, the CAISO commits and dispatches resources. Specifically, pursuant to the Market Redesign and Technology Upgrade

[120] D.02-10-062, p. 52 and Conclusion of Law 11, p. 74.

[121] *See* D.02-12-074, Ordering Paragraph 24b.

(MRTU) program, investor-owned utilities (IOUs) must schedule and/or bid resources based on actual variable generation costs.[122]

The CAISO executes the Security-Constrained Unit Commitment (SCUC) program which is aimed at ensuring both a secure and economical hourly generation schedule and to commit generating units in the day-ahead market (DAM), the hour-ahead scheduling process (HASP), and the real-time market (RTM).[123] The CAISO objective is to minimize energy and ancillary services (A/S) procurement costs based on energy and A/S bids and transmission constraints. The SCUC employs a full network model (FNM) that includes all transmission network buses (in the CAISO balancing authority area) and its transmission constraints. These transmission parameters enable SCUC to derive an efficient market-clearing solution of co-optimizing energy and A/S while managing congestion and transmission losses.[124]

The overall generation production cost as calculated in the Integrated Forward Market (IFM) is determined by the total of the start-up and minimum load cost of CAISO-committed generating units and the energy and A/S bids of all scheduled generating units.[125] The SCUC determines the optimal commitment status and the schedules of generating units by minimizing the start-up, minimum load, bid in energy, and A/S costs, subject to network as well as resource related constraints over the optimization time horizon.[126] This leads to a least-cost multi-product co-optimization methodology that is designed to maximize economic efficiency and consider physical

[122] "Variable costs are the only ones that are incurred or avoided as a result of operating decisions. As DWR, ORA and PG&E point out, to achieve economic dispatch the operating utility needs only to see the variable costs of each DWR contract (or of any other resource in its portfolio)." D.02-09-053 at p. 39.

[123] California Independent Systems Operator Technical Bulletin 2009-06-05 (CAISO Technical Bulletin), Market Optimization Details, June 16, 2009, revised November 19, 2009, pp. 2-3.

[124] *Id.*

[125] *Id.*, p. 2-8.

[126] *Id.*, p. 2-8.

constraints, thereby relieving network congestion.[127] According to CAISO, in theory, the economic efficiency of the market operation could be achieved through a least-cost resource commitment and scheduling with co-optimization of energy and A/S. However, the economic efficiency of the market depends heavily on the presentation of resources by the bidders including the IOUs.

For each generating unit, the Scheduling Coordinator for the three IOUs may submit energy bids representing the price at which the resource is willing to provide the relevant service and megawatt hour amounts offered at that price.[128] As noted above, these costs should correspond with the resource's variable costs. The energy bid includes three parts: the start-up cost, minimum load cost and energy bid curve above minimum load.[129] Start-up cost is incurred whenever a start-up takes place and minimum load cost is incurred whenever the unit is online.[130] The start-up and minimum load costs are ignored when (1) the generating unit self-commits by submitting energy self-schedules and/or providing submissions to self-provide A/S, or (2) where the generating unit must be online due to reliability must run (RMR) requirements or day-ahead binding commitment and A/S awards in RTM.[131] Self-schedules under MRTU are interpreted by CAISO markets as price-taking supply or demand.[132]

The CAISO market provides a financially binding DAM transaction and physically binding RTM position to enable market participants to procure energy and A/S.[133] Generators scheduled in the day-ahead settlement are paid the day-ahead

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[127] *Id.*

[128] *Id.*, p. 2-10.

[129] *Id.*, p. 2-10.

[130] *Id.*

[131] *Id.*

[132] *Id.*

[133] CAISO online training – "Day ahead market overview – CBT" (Apr.14, 2011), *available at*: http://content.caiso.com/training/Day-ahead_Market_Overview/index.html?pg=002.

locational marginal price (LMP) for the megawatts accepted.[134] Scheduled suppliers must produce the committed quantity in real-time or buy power from the real-time marketplace to replace what was not produced.[135]

3. Dispatchable Resources in PG&E's Portfolio

Dispatchable resources have the ability to operate flexibly at levels under the control of PG&E and/or CAISO. PG&E indicated that its dispatchable resources include the following:

- PG&E's retained fossil-fired generation resources (three generating stations described in section 4 below);
- the portion of hydropower generation that is not a must-run resource;
- the Fresno Cogeneration Project;
- sixteen tolling agreements, including those with GenOn Delta LLC and Dynegy Moss Landing LLC (listed in table 10-15 of PG&E's testimony); and
- an allocated CDWR long-term contract (Kings River Conservation district).[136]

According to PG&E, "[d]ispatchable resources with restrictions on the amount and level of dispatch based on contract terms (such as Fresno Cogeneration) were self-scheduled into the CAISO market if they were forecast to be economic in pre-IFM analysis," and that "[a]side from such considerations, dispatchable generation was bid into the IFM and RTM at incremental cost and dispatched via the markets."[137]

4. PG&E's Utility Owned Fossil-Fuel Generating Stations

PG&E reported that during the Record Period it owned, operated and maintained three fossil fuel generating stations: (1) Gateway Generating Station (GGS); (2) Colusa

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[134] *Id.*

[135] *Id.*

[136] PG&E's testimony, pp. 2-14 to 2-15.

[137] *Id.* at p. 2-15.

Generating Station (CGS); and (3) Humboldt Bay Generating Station (HBGS).[138] PG&E provided the following detailed information about these generating stations in their testimony:

a. **Gateway Generating Station (GGS).** PG&E's GGS is a 530 MW combined cycle power plant consisting of two combustion turbine generators (CT), each with its own heat recovery steam generator (HRSG), and a single GE steam turbine generator (ST). In the standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an air cooled condenser. Additionally, GGS is equipped with two capacity enhancing technologies to improve output during peak generation periods including a chiller used to cool incoming air to the CTs and duct burners to increase steam production in the HRSGs, resulting in increased ST output. The chiller and duct burners allow GGS to increase its output by approximately 50 MW.

b. **Colusa Generating Station (CGS).** PG&E's CGS is a 530 MW combined cycle power plant consisting of two CTs, each with its own HRSG, and a single ST. In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an air cooled condenser. Additionally, CGS is equipped with two capacity enhancing technologies to improve output during peak generation periods including an evaporator used to cool incoming air to the CTs and duct burners to increase steam production in the HRSGs resulting in increased ST output. The evaporator and duct burners allow CGS to increase its output by approximately 127 MW.

c. **Humboldt Bay Generating Station (HBGS).** PG&E's HBGS is a 163 MW reciprocating engine power plant consisting of 10 x 18V50 DF natural gas fired reciprocating engines. This facility replaced the old Humboldt Bay Power Plant (HBPP), which has since been retired. Each engine is designed to run on natural gas with 1 percent of total fuel input provided by low sulfur diesel as the pilot fuel. The engines are also designed to run on low sulfur diesel or biodiesel. Each engine is equipped with a separate independent closed loop cooling system.

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[138] PG&E's testimony, p. 5-1.

> HGBS has eliminated the need for once through cooling from Humboldt Bay, and has a closed loop industrial cooling system with low water usage. It [also] has a backup liquid fuel capability which is highly reliable, and is able to quickly follow load.[139]

5. Must-Take Resources in PG&E's Portfolio

PG&E had a number of must-take resources and contracts during the Record Period. Resources are designated as must-take for a number of reasons, including legislative obligations such as the Renewable Portfolio Standard (also see Qualifying Facilities, described in bullet point (1) below); environmental, licensing, or physical requirements (*e.g.*, economic impact of continuous recycling of nuclear resources and hydropower generation, described in section (5) below); or existing contracts. According to PG&E, in comparison to dispatchable resources, the operating utility has no flexibility in the delivery of energy for must- take resources.[140] All energy produced by these resources must be taken by the transmission grid, except in cases where transmission constraints make it physically impossible for the power to flow.[141] PG&E indicates that "[it] generally self-schedules must-take supply in the day-ahead market and then modifies these self-schedules in real-time if the forecast of generation has changed."[142] PG&E's portfolio of must take resources include the following:

1) Existing Qualifying Facilities (QF): with the exception of limited curtailment provisions provided for certain QF projects and the day ahead dispatchability of the Fresno Cogeneration Project, PG&E's existing QF Power Purchase Agreements (PPA) allow QFs to decide what level of generation to provide. Existing QF PPAs are considered must take resources;
2) Renewable contracts;
3) Diablo Canyon Nuclear Power Plant;

[139] PG&E's testimony, p. 5-1 to 5-3.

[140] PG&E's testimony, p. 2-17.

[141] *Id.*

[142] *Id.* at p. 2-10.

4) Existing contracts: PG&E had obligations to purchase or exchange power under existing contracts (e.g., Etiwanda and the City and County of San Francisco), which were settled as financial inter SC trades;

5) Must-take hydro generation: Certain power plants have environmental, licensing or physical requirements that require continuous operations. For instance, certain run-of-river hydro resources are inherently nondispatchable because they have no reservoir controls, or wind or solar generators[143].

E. DISCUSSION AND ANALYSIS

1. PG&E's Approach to Ensuring Least-Cost Dispatch

PG&E claims that it has fully complied with SOC 4 and related Commission decisions addressing LCD practices, during the entire Record Period.[144] According to PG&E, it uses the following approach to dispatch its resources in a manner that maximizes ratepayer benefits:

1) Self-schedule must-take resources to ensure the CAISO will commit and dispatch these resources;

2) Bid dispatchable thermal resources at incremental cost to allow the CAISO to commit and dispatch the resource only when the resources' variable costs can be recovered;

3) Self-schedule dispatchable resources in cases where the CAISO markets are likely to cycle off and on due to the IFM's 24-hour scheduling horizon or because cycling costs are simply not captured correctly due to market rules;[145]

4) Bid dispatchable hydro resources at opportunity cost to defer generation to the highest price hours.

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[143] *Id.*

[144] PG&E's Testimony, p. 2-1.

[145] According to PG&E, "[d]uring the record period, PG&E compared its forecast of the benefits of keeping thermal units on versus its forecast of what the CAISO market systems would see as the benefits of keeping them on: when the forecast benefits exceeded the forecast of CAISO calculated benefits, PG&E generally kept such units on by self committing them." *Id.*, p. 2-11.

2. DRA's Analysis of PG&E's Overall Approach to Attaining Least-Cost Dispatch

As described above, the scope of DRA's analysis for the Record Period was focused on energy bids submitted by PG&E's dispatchable fossil fueled resources to CAISO in the day-ahead market. Acknowledging the limits of its analysis in advance, DRA found that PG&E consistently submitted bids for its dispatchable fossil fueled resources at incremental cost in the day-ahead market. However, although PG&E consistently bid fossil fueled resources to the day-ahead CAISO market at incremental cost, [redacted] as explained in detail in Section C.3 below.

3. DRA's Review of PG&E's Incremental Cost Bids Submitted to the CAISO Market

DRA conducted a review of energy bids submitted by PG&E to CAISO, across a sample of fossil fuel generating stations in its portfolio, to verify whether PG&E met its least-cost dispatch obligations by consistently and comprehensively submitting energy bids for dispatchable resources at incremental cost during the Record Period. The sample of dispatchable fossil fueled resources in DRA's analysis comprised all three UOG stations described in detail above, and two of the fourteen dispatchable units that fall under tolling agreements - Panoche Energy Center (LLC) and Mariposa Energy (LLC). PG&E states that it calculates incremental cost of energy bids using the following formula:[146]

Incremental cost = (Fuel Price multiplied by Incremental Heat Rate (IHR)) plus the Variable Operations and Maintenance cost (VOM)

DRA's analysis examined whether PG&E correctly applied the incremental cost formula above consistently in the calculation of energy bids from its dispatchable resources.

[146] PG&E's response to DRA's Data Request 8 (received May 24, 2013).

Along with Application 13-02-023, PG&E submitted: (1) a dataset of bid sheets representing all the hourly energy, ancillary service, and RUC bids submitted to CAISO from each dispatchable resource in the day-ahead market. PG&E also submitted the following datasets for each hour of the record year for the same resources: (2) fuel prices, (3) incremental heat rates, and (4) variable operations and maintenance costs. In practice, the cost parameters represented in datasets (2) through (4) do not vary intra-day, which means that the bid price varies on a daily but not an hourly basis.

DRA independently calculated the set of incremental costs for all hours of the Record Period (when the sample resources noted above were operational) by using data from datasets (2), (3) and (4). These incremental cost calculations were then compared to the bid sheets submitted by PG&E to CAISO for verification purposes.

Next, DRA examined the implication of any incorrectly calculated energy bids in terms of market awards. For instance, if a resource submitted any bids where incremental costs were overestimated, that could potentially mean that the resource failed to receive a market award where in fact it was merited. In this case if the 'true' bid was significantly lower than the relevant LMP, then the resource should have received a market award, and any market purchases that were made due to the non-operation of the resource for the period affected by the incorrect energy bid(s) would have been at a price higher than the cost of generating power at the resource. This situation would have led to a net loss to ratepayers. The reverse situation is also possible where a resource's bid costs are underestimated. Here, the potential exists for a resource to receive an award, where in fact buying energy from the market would represent better value for ratepayers (once the original bid is adjusted for errors).

a. DRA's Conclusions on PG&E's Incremental Cost Bids

DRA discovered that in the cases of [redacted] Generating stations PG&E [redacted][147]:

[147] Based on DRA analysis of spreadsheet called "Fuel Price VOM IHR" and compared with daily bid sheets, both located in PG&E workpapers volume III .

[redacted]

In the events noted above, energy bids were not equal to the incremental fuel cost multiplied by the incremental heat rate plus the variable operations and maintenance cost (*i.e.*, the formula that PG&E reportedly uses to calculate incremental cost of energy bids). On discovering this issue, DRA propounded a data request requesting PG&E to explain the variances in the calculation of the bids listed above. In the cases of [redacted] [redacted], DRA discovered very few errors of this type.

b. PG&E's Explanation for Variances in Incremental Cost Calculations

PG&E cited five main reasons for their incremental cost variances (the majority of which are attributed to reasons (1) and (2) below):[149]

[redacted]

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[148] [redacted]

[149] DRA submitted Data Request 10 on May 23, 2013 and PG&E responded on June 7, 2013. DRA submitted Data Request 12 on May 31, 2013 and PG&E responded on June 14, 2013.

[150] Conference call between DRA and PG&E (July 17, 2013).

[redacted]

c. **PG&E's Implementation of Variable Operations & Maintenance (VOM) Costs**

[redacted][151] [redacted] for contracted resources were introduced on July 21, 2012. DRA

[151] *Id.*

believes that the [redacted] should be included on all bids and, going forward, recommends that PG&E continues to do so.

PG&E has used an alternative approach to estimating Humboldt Bay’s VOM in its bids. PG&E indicated that “[b][redacted][152] [redacted] DRA finds this approach to be inconsistent with LCD principles because it leads to presentations of fluctuating VOM costs that diverge from the true incremental costs of this resource. DRA recommends that PG&E submits to DRA an alternative method to regulating the number of starts to comply with its environmental obligation which also represents the lowest possible incremental cost. DRA is willing to consult with PG&E on formulating this alternative method.

d. Impact of Incorrect Bids on Determination of Market Awards

[redacted].[153] [redacted]

[152] *Id.*

[153] As noted in Section D. below, the majority of incorrect bids did not coincide with outages.

F. DRA RECOMMENDATIONS

1) Based on further analysis, DRA recommends that PG&E finds a more robust and permanent solution to the [redacted] described in section C.3.b., explanation (1). [redacted] these costs should be included on a daily basis to comply with PG&E's obligation to bid at true incremental cost, and provide for more accurate bids. Also, PG&E needs to ensure that the IT solution that was implemented is consistent with its operating practices, [redacted].

DRA further recommends that PG&E institute business practices that integrate the activities of their business units involved in energy dispatch with those of the IT function servicing them to ensure that solutions are implemented with extensive consultation with each other.

2) Based on further analysis, DRA finds that PG&E's explanation (2) in section C.3.b. is unsatisfactory. PG&E notes that [redacted], resulting in a "tech-down" bid. [redacted] Therefore, [redacted] is not the reason for the majority of calculation errors as claimed by PG&E.[154]

PG&E should ensure that the availability of resources is accurately recorded within their dispatch operations and the bid creation software in particular. In addition, to avoid confusion, whenever a unit is unavailable, no bids should be generated for that resource for the time period affected. This should be reflected in the bid sheets received by DRA as part of PG&E's filing (work papers volume III).

[154] PG&E response to DRA Data Response 10 (received June 7, 2013).

3) PG&E needs to find a more robust solution in cases where [redacted], so that they more accurately reflect incremental costs, as described in section C.3.b.

4) Variances due [redacted] reasons should be further investigated, and PG&E should find an adequate resolution in both cases, as described in section C.3.b.

5) DRA believes that the [redacted] In the case of [redacted]

In relation to recommendations (1) – (5) DRA requires that PG&E present a compliance filing 30 days subsequent to the final decision in this proceeding, to:

- demonstrate the level of progress that has been made in identifying a comprehensive solution to these [redacted] problems identified in this testimony, and
- set out a timeline stating when each solution will be finalized and implemented.

Chapter 6

Witness: Grant Novack

DIABLO CANYON SEISMIC STUDIES BALANCING ACCOUNT

A. SUMMARY

The following table presents costs recorded by PG&E in the Diablo Canyon Seismic Studies Balancing Account (DCSSBA) through December 31, 2012, by category:

TABLE 6-1

DIABLO CANYON SEISMIC STUDIES BALANCING ACCOUNT

RECORDED COSTS

Line No.	Category	Recorded Costs as of 12/31/2012 ($ Million)
1	Seismic Survey Design	$0.85
2	Offshore 2-D/3-D LESS	$12.52
3	Offshore 3-D HESS	$8.2
4	Onshore 2-D	$14.32
5	OBS Installation	$0.99
6	Project Management	$3.01
7	Total	$39.89

DRA recommends disallowance of $3.76 million costs that PG&E included in the $8.2 million recorded for Offshore 3-D high-energy seismic surveys (HESS).

B. AUDIT OBJECTIVES, SCOPE, AND PROCEDURES

DRA reviewed PG&E's DCSSBA for the entries made between August 2010 and December 2012. The objective of DRA's review was to determine whether entries recorded in the account were appropriate, correctly stated, and in compliance with the applicable Commission decisions.

DRA's audit procedures included, but were not limited to the following:

- Reviewed PG&E's application testimony, exhibits, workpapers, and Master Data Request responses. Prepared and issued Data Requests and reviewed PG&E's responses.
- Reviewed applicable Advice Letters and Commission Decisions.
- Selected a sample of DCSS monthly line items to determine whether adequate support exists. Examined invoices, journals, general ledger entries, and related materials for amounts recorded in the DCSS balancing account. Verified the mathematical accuracy of accounting worksheets and supporting documentation. Visited PG&E to review and discuss each of the selected DCSS monthly line items in detail with PG&E staff, and to trace those line items to PG&E's General Ledger.
- Reviewed to determine whether costs recorded were appropriate and correctly stated.
- Reviewed to determine whether PG&E complied with applicable decisions and Advice Letters.

On a sample test basis, DRA reviewed source documents that supported costs recorded in the DCSS balancing account. DRA's sample was judgmentally selected, and consisted of twenty monthly line items recorded. A "judgment sample" is a type of nonrandom sample, which is selected by the auditor based on the judgment (opinion) of the auditor. Factors considered when selecting a judgment sample include auditor judgments about various elements including but not limited to the internal control environment, exposure/materiality, and risk.

C. DISCUSSION

In its testimony, PG&E stated:

> The costs recorded in the DCSSBA through December 31, 2012, were incurred for activities related to seismic survey design, offshore three dimensional (3-D) high energy seismic surveys (HESS), offshore 2-D and 3-D low energy seismic surveys (LESS), onshore 2-D seismic surveys, and ocean bottom seismometer (OBS) installation. Also recorded in the DCSSBA are permitting and mitigation costs and project management costs for each of the seismic surveys. Project management costs include costs of

> PG&E personnel and labor, nuclear quality assurance, and the [Independent Peer Review Panel] IPRP.[155]

PG&E planned to conduct 3D high-energy seismic surveys in four offshore areas during the fall of 2012, subject to obtaining all necessary permits. PG&E submitted its Coastal Development Permit (CDP) application to the California Coastal Commission (CCC) in April 2012. As the Independent Peer Review Panel (IPRP) and environmental permitting process advanced, PG&E significantly reduced the scope of the offshore HESS due to concerns raised by the IPRP, environmental groups, and commercial fisherman. In August 2012, the California State Lands Commission (CSLC) approved the geophysical survey permit for a project that would allow PG&E to collect data from only three survey areas. In response to CCC requests, PG&E provided additional information supporting its CDP application right up until the CCC hearing on November 14, 2012, and further reduced the proposed survey areas from three to one. However, the CCC ultimately denied PG&E's CDP application.[156]

In anticipation of and in preparation for completing the offshore HESS in the fall of 2012, PG&E reported in its testimony to have incurred and recorded costs totaling \$8.20 million to the DCSSBA, comprised of the following: (1) permitting: \$2.97 million; (2) environmental monitoring and mitigation programs: \$1.47 million; and (3) survey vessel contracting and Nuclear Quality Assurance (NQA) for seismic data acquisition: \$3.76 million.[157]

The \$3.76 million survey vessel contracting and NQA costs include (1) costs to implement NQA procedures for certifying *R/V Marcus Langseth* survey equipment as well as marine geophones, onshore geophones, and other seismic survey equipment, and (2) costs for pre-cruise mobilization of the *R/V Langseth* for the offshore HESS.

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[155] PG&E's Testimony, pp. 7-1 to 7-2.

[156] *Id.* at pp. 7-4 to 7-5.

[157] *Id.* at pp. 7-5 to 7-6.

In its testimony, PG&E stated:

> The CSLC [California State Lands Commission] authorized PG&E to perform the studies in August 2012, and PG&E had a *reasonable expectation* that the CCC [California Coastal Commission] also would authorize PG&E to conduct the HESS. In light of that, and to ensure that it could undertake the studies as soon as they were permitted by these agencies, PG&E actively pursued all of the tasks necessary to support the HESS.[158]

PG&E originally proposed to conduct 3D high-energy seismic surveys in *four* offshore areas. However, as the Independent Peer Review Panel (IPRP and environmental permitting process advanced, PG&E ultimately found it necessary to reduce the proposed survey areas to only *one* offshore area. PG&E's failed to provided sufficient evidence of a "reasonable expectation" that the CCC would authorize PG&E to conduct the offshore 3-D HESS. DRA concluded that there should have been a reasonable expectation the CCC may deny such authorization. PG&E should have waited until the CCC granted the permit to proceed before incurring the $3.76 million costs for survey vessel contracting and NQA. The $3.76 million expenditure was premature and imprudent because the CCC had not yet approved PG&E's CDP application, and the CCC ultimately denied the application. In other words, PG&E's expenditures in the amount of $3.76 million to prepare for seismic studies that were contingent on obtaining the CDP were not incurred in the ordinary and prudent course of business.

[redacted] However, without the permit from the CCC, PG&E should not have moved forward with the offshore HESS and,

[158] PG&E's Testimony, p. 7-2 (emphasis added).

therefore, the entire $3.76 million incurred for survey vessel contracting and NQG for seismic data acquisition was unproductive and of no benefit whatsoever to seismic studies or to ratepayers.

D. CONCLUSIONS AND RECOMMENDATIONS

DRA recommends disallowance of the $3.76 million costs PG&E incurred and recorded for survey vessel contracting and NQA for seismic data acquisition. Under the facts and circumstances, the $3.76 million costs do not qualify as operation and maintenance expenses incurred in the ordinary and prudent course of business. Considering DRA's recommendation that the $3.76 million should not be recovered in rates, DRA recommends PG&E recover in rates $36.13 million total expenses incurred during 2011-2012 and not the $39.89 million total that PG&E has recorded. Of the $36.13 million total expenses incurred, PG&E has already recovered $14.41 million in 2011 and 2012 rates. Therefore, DRA recommends that the difference of $21.72 million plus the Franchise Fees and Uncollectible Accounts (FF&U) of $234,359 (using the factor 0.010790) be included in rates in this proceeding.

[redacted]

Except for the Offshore 3-D HESS, DRA found no other exceptions to the recovery requirements. The remaining entries in the DCSS Balancing Account are appropriate, correctly stated, and in compliance with Commission decisions.

Chapter 7

Witness: Grant Novack

MARKET REDESIGN & TECHNOLOGY UPGRADE (MRTU)

A. SUMMARY

PG&E requests that the California Public Utilities Commission fine $3.583 million in capital expenditures and $0.064 million in expense as incremental amounts are reasonable and recoverable in rates. These costs are associated with PG&E's Information Technology (IT) incremental capital and expense expenditures to meet the requirements of the CAISO Market Design Initiatives that became operational in 2012, as well as stabilization costs on initiatives that became operational in December 2011.

B. AUDIT OBJECTIVES, SCOPE, AND PROCEDURES

DRA reviewed PG&E's Market Redesign and Technology Upgrade Memorandum Account (MRTUMA) for projects that became operational in 2012. The objective of DRA's review was to determine whether entries recorded in the account were appropriate, correctly stated, and in compliance with the applicable Commission decisions.

DRA's audit procedures included, but were not limited to the following:

- Reviewed PG&E's application testimony, exhibits, workpapers, and Master Data Request responses. Prepared and issued Data Requests and reviewed PG&E's responses.
- Reviewed applicable Advice Letters and Commission Decisions.
- Selected a sample of MRTUMA monthly line items to determine whether adequate support exists. Examined invoices, journals, general ledger entries, etc. for amounts recorded in the MRTUMA. Verified the mathematical accuracy of accounting worksheets and supporting documentation. Visited PG&E to review and discuss each of the selected MRTUMA monthly line items in detail with PG&E staff, and to trace those line items to PG&E's General Ledger.
- Reviewed MRTUMA entries and supporting documents to determine whether costs recorded were appropriate and correctly stated.

- Reviewed MRTUMA entries and supporting documents to determine whether PG&E complied with applicable decisions and Advice Letters.

On a sample test basis, DRA reviewed those source documents that supported costs recorded in the MRTUMA. DRA's sample was judgmentally selected and consisted of ten monthly line items recorded. A "judgment sample" is a type of nonrandom sample, which is selected by the auditor based on the judgment (opinion) of the auditor. Factors considered when selecting a judgment sample include auditor judgments about various elements including but not limited to the internal control environment, exposure/materiality, and risk.

C. DISCUSSION

Tables 7-1 and 7-2 below summarize PG&E's IT incremental capital and expense expenditures from the CAISO market design releases in December 2011, Spring 2012, and Fall 2012.

TABLE 7-1
IT INCREMENTAL CAPITAL EXPENDITURES
FOR PROJECTS THAT BECAME OPERATIONAL IN 2012
(000s OF NOMINAL DOLLARS)

Line No.	Incremental Capital Expenditures	Total Costs
1	IT CAISO Market Design Initiatives Incremental Direct Labor	
2	December 2011 Release	$171
3	Spring 2012 Release	615
4	Fall 2012 Release	2,150
5	Total IT Incremental Direct Labor	$2,936
6	Other Costs(a)	$558
7	Hardware and Purchased Software	89
8	Total IT Incremental Capital Expenditures	$3,583

(a) Other Costs include A&G, AFUDC, Material Burden and Adjustments.

TABLE 7-2
IT INCREMENTAL EXPENSES FOR PROJECTS THAT BECAME OPERATIONAL IN 2012
(000s OF NOMINAL DOLLARS)

Line No.	Incremental Program Expenses	Total Costs
1	Market Design Initiatives Project Expenses	$3
2	IT Ongoing Business Expenses	$61
3	Total IT Incremental Program Expenses	$64

D. CONCLUSIONS AND RECOMMENDATIONS

DRA's review did not note any items of a material nature requiring adjustments to PG&E's recorded incremental capital expenditures of $3.583 million associated with the CAISO's December 2011. DRA's review did not note any items of a material nature requiring adjustments to PG&E's recorded incremental IT expenses of $0.064 million, which supported the capital projects, as well as PG&E's initiated specific work in order to effectively operate in the CAISO's newly redesigned markets.

Chapter 8

Witness: Grant Novack

ERRA BALANCING ACCOUNT

A. SUMMARY

The ERRA balancing account activity for the Record Period (January 1, 2012 to December 31, 2012) resulted in an over-collected balance of $74,797,023. DRA found no required accounting adjustments and no exceptions to the recovery requirements. DRA found that the ERRA entries are appropriate, correctly stated, and in compliance with Commission decisions.

B. AUDIT OBJECTIVES, SCOPE, AND PROCEDURES

DRA reviewed PG&E's ERRA Balancing Account for the Record Period. The objective of DRA's review was to determine whether entries recorded in the accounts were appropriate, correctly stated, and in compliance with the applicable Commission decisions.

DRA's audit procedures included, but were not limited to the following:

- Reviewed PG&E's application testimony, exhibits, workpapers, and Master Data Request responses. Prepared and issued Data Requests and reviewed PG&E's responses.
- Reviewed applicable Advice Letters and Commission Decisions.
- Performed analytical reviews of monthly entries, including reviews of monthly balances recorded for each of the ERRA tariff line items during the year, and evaluated monthly and annual fluctuations.
- Selected a sample of ERRA monthly/tariff line items to determine whether adequate support exists. Examined invoices, journals, general ledger entries, etc. for amounts recorded in the ERRA balancing account. Verified the mathematical accuracy of accounting worksheets and supporting documentation. Visited PG&E to review and discuss each of the selected ERRA monthly/tariff line items in detail with PG&E staff and to trace those line items to PG&E's General Ledger.
- Reviewed Monthly Interest Rates used and the interest amount calculations.

- Reviewed to determine whether revenues and costs recorded were appropriate and correctly stated.
- Reviewed to determine whether PG&E complied with applicable decisions and Advice Letters.
- Reviewed copies of internal audit reports issued during the Record Period related to balancing account administration.

On a sample test basis, DRA reviewed those source documents that supported revenues, costs, and expenses recorded in the ERRA. DRA's sample was judgmentally selected, and consisted of thirty-one monthly/tariff line items recorded in the ERRA. A "judgment sample" is a type of nonrandom sample, which selected by the auditor based on the judgment (opinion) of the auditor. Factors 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.

DRA examined thirty-one ERRA monthly balancing account tariff line items. The tariff line items record revenues and power costs (not including California Department of Water Resources (DWR) contract costs) associated with PG&E's authorized procurement plan, pursuant to Decision 02-10-062, Decision 02-12-074, and California Public Utilities Code § 454.5(d)(3). Revenues received from Schedule Transitional Bundled Service Electric Commodity Prices (TBCC) are also recorded in the ERRA balancing account.

C. DISCUSSION

The ERRA accounting entries for the Record Period are summarized as follows:

Beginning Balance		($84,593,899)
Revenues Net of FF&U	($3,603,589,724)	
Net Costs and Expenses	3,593,682,991	
Net Activity Before Interest		$9,906,733
Interest		(109,857)
Ending Balance		($74,797,023)

D. CONCLUSIONS AND RECOMMENDATIONS

DRA's review did not note any items of a material nature requiring adjustments to PG&E's ERRA. DRA noted no exceptions to the recovery requirements adopted by the Commission for this account.

Chapter 9

Witness: Michael Yeo

MAXIMUM DISALLOWANCE FOR STANDARD OF CONDUCT 4 VIOLATION

A. SUMMARY

DRA recommends the maximum disallowance for PG&E's violation(s) of Standard of Conduct 4 (SOC4) for the Record Period be $162,212,000.

B. BACKGROUND

In D.02-10-062 (October Decision), the Commission discussed the need to adopt standards and criteria to guide utilities' behavioral conduct and personnel. In that decision, the Commission established seven minimum standards of behavior, including SOC4, which provided: "[t]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[159]

In a subsequent decision, D.02-12-074 (December Decision), the Commission adopted a limit for potential disallowances derived from violations of SOC in Ordering Paragraph 25. This maximum disallowance risk exposure is equal to twice the utilities' annual procurement administrative expenditures.[160]

The Commission also indicated that "the annual administrative expenses for all procurement functions, includ[e] those related to DWR contract administration, utility-retained generation, renewables, QFs, demand-side resources, and any other procurement resources."[161]

In D.03-06-067, the Commission modified Ordering Paragraph 25 as follows:

[159] D.02-10-062, p. 50–52.

[160] D.02-12-074, pp. 77–78, Ordering Paragraph 25.

[161] Id. at. p. 55.

> Ordering Paragraph 25 is modified to read: We set an annual maximum potential disallowance for violation of Standard #4 at twice each utility's annual expenditures on all procurement activities . . . . For PG&E this amount is $36 million based on its 2003 General Rate Case request for $17.8 million dollars . . . . The specific dollar amounts for each utility shall be reviewed, and revised if appropriate, in each general rate case or cost of service proceeding. Setting this maximum amount supercedes, to the extent that it is not consistent with, any decision on Department of Water Resources and utility operating agreements or orders issued in this docket.

C. DISCUSSION

In the 2010 ERRA compliance review proceedings for the three California investor owned utilities (IOUs), DRA sought disallowances with regard to their least-cost dispatch operations.[162] Because the 2010 disallowance amount cap for SOC4 was not addressed in the record of the proceeding for any of the three IOUs, the presiding Administrative Law Judge (ALJ) in all three proceedings issued rulings requesting additional information on the disallowance amount after the hearings and briefing period had already concluded.

In this application, DRA is providing the disallowance cap amount with this testimony because PG&E's testimony does not include such information. In the event that the Commission finds that PG&E violated SOC4, the disallowance cap information will be available for the Commission's consideration. Also, going forward, DRA believes that the IOUs should be providing disallowance cap information with their testimonies.

D. DISCOVERY

DRA requested information on PG&E's 2012 annual administrative expenses in Data Request 15 (DR 15). DRA asked PG&E to provide those expenses broken down by procurement functional areas as indicated in the December Decision:

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[162] *See generally*, A.11-02-011 (PG&E's ERRA compliance application for Record Period 2010); A.11-04-001 (SCE's ERRA compliance application for Record Period 2010); and A.11-06-003 (SDG&E's ERRA compliance application for Record Period 2010).

- DWR contract administration,
- utility-owned generation,
- renewables,
- QFs,
- demand-side resources, and
- any other procurement resources.

PG&E responded that its 2012 annual administrative expenses are derived from the Electric Supply Administration (ESA) costs as approved by the Commission during the 2011 General Rate Case (GRC), A. 09-12-020. The ESA cost categories different than the procurement functional areas listed above.[163] Therefore, DRA was unable to determine the amounts that PG&E was authorized to recover for each of the procurement functional categories established in the December Decision.

Based on the information provided by PG&E in its Data Request response (Attachment 9.1), the total annual administrative expenses for all procurement activities in 2012 was $81.106 million, which corresponds to the amounts that the Commission approved in the 2011 PG&E GRC application, A.09-12-020.[164] Therefore, the maximum disallowance on SOC4 violation(s) is twice $81.106 million, for a total of $162.212 million.

D. CONCLUSIONS AND RECOMMENDATIONS

DRA recommends:

1) that the maximum disallowance for PG&E's violation(s) of SOC4 be $162.212 million for this Record Period.
2) that, commencing for Record Period 2013, PG&E include, in its annual ERRA testimony, information and workpapers for the maximum disallowance amount for violations of SOC4 for the Record Period.

[163] PG&E's Exhibit PG&E-5– Business Support (AB), Acq & Manage Elect Supply (CT) and Gas Procurement (CV), p. 6-88.

[164] *See* Attachment, PG&E's response to DRA's data request 9.1., which requested PG&E to provide information about the amount for administrative expenses approved by the Commission in the 2011 PG&E GRC, A.09-12-020.

3) that, commencing for Record Period 2013, PG&E provide the maximum disallowance amount broken down by Major Work Categories (MWC) and show how those different costs by MWC were derived from the total Commission-approved GRC amount.

ATTACHMENT 9.1

PG&E Data Request No.:	DRA_020-01		
PG&E File Name:	ERRA-2012-PGE-Compliance_DR_DRA_020-Q01		
Request Date:	July 30, 2013	Requester DR No.:	020
Date Sent:	August 13, 2013	Requesting Party:	Division of Ratepayer Advocates
PG&E Witness:	Sujata Pagedar	Requester:	Michael Yeo

20.14 GENERAL

QUESTION 1

Follow-up questions to DR #15

20.14.1. Please provide the Commission-approved amount on the 2012 administration procurement expenses in a table showing the breakdown by procurement functions (DWR contract administration, utility-retained generation, renewables, QFs, demand-side resources, and any other procurement resources) as listed in D.02-12-074 (mimeo, page 55). If PG&E does not have the cost breakdowns by those procurement functions, please state why and

20.14.1.1. show the breakdown by PG&E major work categories;

20.14.1.2. show how those different costs by major work categories were derived from the total CPUC-approved GRC amount in the 2011 GRC A.09-12-020; and

20.14.1.3.identify whether MRTU administration expenses were included, and indicate what those inclusions are.

ANSWER 1

As PG&E stated in response to Question 1 of DRA_015, PG&E does not plan, budget, or track the costs associated with Electric Supply Administration in the categories listed. The maximum disallowance cap for SOC4 activities includes activities related to least-cost dispatch and contract administration. PG&E's request for funding related to its Electric Supply Administration request costs for the Energy Supply organization which manages dispatch for PG&E's entire portfolio, including DWR, URG, Renewables, QFs, demand-side resources. More specifically, PG&E's 2011 GRC Opening Testimony describes PG&E's Energy Procurement organization's responsibilities as including, front-office functions associated with planning, procuring, scheduling, and dispatching resources, and back-office functions associated with ensuring accurate payments to the

CAISO and other power suppliers.[165] Energy Procurement is also responsible for renewable resource procurement, development and compliance.

20.14.1.1.The cost breakdown by major work cateogory is shown on the attached sheet. The major work categories included in electric supply administration's GRC request include the following MWC. It should be noted that the MWC included in Electric Generation's authorized GRC revenue requirement associated with Energy Procurement only include the first two major work categories. MWC CV - Gas procurement, in not included in Electric Generation's authorized GRC revenue requirement request.

- MWC AB - Support - represents the office of the SVP of Energy Procurement, along with the administrative support functions for the chief of Staff, business planning, budgeting, and financial and operational reporting.
- MWC CT - Acquire and Manage Electric Supply - represents the resources necessary for electric procurement operations for bundled electric supply, including electric generation related gas procurement. These functions include Energy Policy, Planning and Analysis, Energy supply Management, Renewable Energy Contract Management and Settlements, and energy Compliance and Reporting.
- MWC CV - Gas Procurement - includes the resources necessary for gas procurement operations for gas supply to PG&E core customers.

20.14.1.2.The costs included in the CPUC authorized revenue requirement, by Electric Supply Administration major work categories is shown in the attached sheet.

20.14.1.3.PG&E's 2011 GRC did not include capital and expense associated with the systems and infrastructure that was part of the MRTU Markets and Performance (MAP) Program implementation and tracked in the MRTUMA. As noted on page 6-72, PG&E of PG&E's 2011 GRC request, PG&E had plans to request cost recovery for post Release 1 technology-related cost for MRTU implementation through a review of the MRTUMA in another application, as ordered by the Commission.

These costs were requested through a series of applications filed in 2011 and 2012. See A.10-02-012, A.11-02-011, and A.12-04-009.

PG&E's 2011 GRC included a request associated with Energy Procurement personnel time related to the MRTU Project Section of the Energy Supply organization.[166]

[165] See PG&E's 2011 GRC Opening Testimony, Exhibit 5, Chapter 6, Introduction.

[166] See discussion in Exhibit 5, Chapter 6, page 6-70 through 6-72.

Attachment 9.1 (continued)

DRA_020	Electric Supply Administration - Amounts Requested and Authorized in the General Rate Case					
Line Number		**UCC 141-Energy Procurement By Major Work Category**	**Authorized Total ($000s)**	**Original Request**	**Settlement Concessions**	**Imputed Regulatory Amount[10]**
1		**Results of Operation**				
2		**Electric Generation - Electric Procurement**				
3	RO Line #	MWC: **AB - Support**[3]				
4	5	Expense - Production	$ 2,061			
5	12	Expense - Allocated A&G estimate	$ 64			
6	21	Taxes - Payroll Taxes - allocated estimate	$ 92			
7		**Total AB - Support**	**$ 2,216**	**$ 2,404**	**$ (188)**	**$ 2,216**
8						
9		MWC: **CT - Acquire and Manage Electric Supply**[4,5]				
10	5	Expense - Production	$ 42,316			
11	12	Expense - Allocated A&G estimate	$ 10,415			
12	21	Taxes - Payroll Taxes - allocated estimate	$ 1,329			
13		**Total CT - Acquire and Manage Electric Supply**	**$ 54,060**	**$ 89,060**	**$ (35,000)**	**$ 54,060**
14						
15		MWC: **CV - Gas Procurement**[6]	N/A	$ 4,535	$ (398)	$ 4,137
16		MWC: **FB - Maintenance of Computing Network & Systems**[7,9]				
17	5	Expense - Production	$ 2,001			
18		MWC: **IM - Information Technology Applications**[7,8]				
19	5	Expense - Production	$ 2,305			
20		Line 5: Expense - Production Total	$ 48,683			
21		Line 12: Expense - A&G Subtotal - allocated estimate for select MWC	$ 10,479			
22		Line 21: Taxes - Payroll Tax Subtotal - allocated estimate for select MWC	$ 1,421			
23		**Partial Subtotal of Expense $ in RO Model related to select MWC**	**$ 60,582**	**$ 96,000**	**$ (35,586)**	**$ 60,414**
24		**Authorized Revenue Requirement - Energy Procurement**				
25	**Expenses**					
26	5	Production	$ 48,683			
27		less production amounts allocated to MWCs above	$ (48,683)			
28	10	Uncollectables	$ 251			
29	12	A&G	$ 17,190			
30		less A&G amounts allocated to MWCs above	$ (10,479)			
31	13	Franchise Requirements	$ 612			
32	14	Amortization	$ 1,700			
33	Taxes					
34	20	Property	$ 169			
35	21	Payroll	$ 2,765			
36		less tax amounts allocated to MWCs above	$ (1,421)			
37	22	Business	$ 23			
38	23	Other	$ 52			
39	24	State Corporation Franchise	$ 460			
40	25	Federal Income	$ 2,984			
41	Depreciation					
42	27	Depreciation	$ 4,027			
43	Return					
44	31	Net for Return	$ 2,101			
45		Authorized Revenue Requirement	$ 81,017	$ 96,000	$ (35,586)	$ 60,414

Footnote 1: The maximum disallowance cap for SOC4 activities includes activities related to least-cost dispatch and contract administration. PG&E's Energy Supply organization manages dispatch for PG&E's entire portfolio, which includes DWR, URG, Renewables, QFs, demand-side resources. See PG&E's 2011 GRC Opening Testimony, Exhibit 5, Chapter 6, Introduction, PG&E's Energy Procurement (EP) organization is responsible for front-office functions associated with planning, procuring, scheduling, and dispatching resources, and back-office functions associated with ensuring accurate payments to the CAISO and other power suppliers. IP also is responsible for renewable resource procurement, development and compliance.

Footnote 2: PG&E's 2011 GRC did not include capital and expense associated with the systems infrastructure that was part of the MRTU Markets and Performance (MAP) Program implementation and tracked in the MRTUMA. As noted on page 6-72 of PG&E's ERRA Compliance Testimony, PG&E plans to request cost recovery for post Release 1 technology-related cost for MRTU implementation through a review of the MRTUMA in another application. Specifically, these costs were requested through a series of applications filed in 2010 and 2011, see A.10-02-012, A.11-02-011, and A.12-04-009. PG&E's 2011 GRC did include a request associated with Energy Procurement personnel time related to MRTU Project Section. See discussion in PG&E's 2011 GRC Testimony, Exhibit 5, Chapter 6, page 6-70 through 6-72.

Footnote 3: MWC AB - Support - represents the office of the SVP of Energy Procurement, along with the administrative support functions for the chief of Staff, business planning, budgeting, and financial and operational reporting.

Footnote 4 & 5: MWC CT - Acquire and Manage Electric Supply - represents the resources necessary for electric procurement operations for bundled electric supply, including electric generation related gas procurement. These functions include Energy Policy, Planning and Analysis, Energy supply Management, Renewable Energy Contract Management and Settlements, and energy Compliance and Reporting.

Footnote 6: MWC CV - Gas Procurement - includes the resources necessary for gas procurement operations for gas supply to PG&E core customers.

Footnote 7: Maintenance of Computing Network & Systems - includes costs to operation and maintain computing networks and supporting systems. In 2011, MWC FB was replaced by MWC JV.

Footnote 8: IT Applications - includes costs to design, develop, upgrade and maintain IT applications across the Company. IN 2011, MWC IM was replaced by MWC JV.

Footnote 9: MWC JV - Maintain Applications and Infrastructure - Beginning in 2011, MWC JV is the sole identifier for all IT expense, replacing all previous MWCs (AK, BP, FB, IM, IN, IO) used for IT work. MWC J includes costs for ongoing maintenance and operations and repair for PG&E's applications, systems, and infrastructure.

Footnote 10: Calculation of imputed regulatory value: the requirement in OP 42 of D.11-05-018 that the Company identify, by MWC, the amounts assumed in the SA requires to derive various amounts not specified in the SA. The SA did not provide specific values for most MWCs. The SA identified specific levels for only those MWCs identified in D.11-05-018, Attachment 1 , Appendix A, page 1-A3. Since the final decision was not issued until May 2011, PG&E developed a budget in June 2011. Adjustments include SA call-out, non call-out, and SA burden/payroll tax / chargeback adjustments.

APPENDIX A

Qualifications of Witnesses & Testimony Declarations

QUALIFICATIONS AND TESTIMONY DECLARATION
OF
YAKOV LASKO

Q.1 Please state your name and business address.
A.1 My name is Yakov Lasko. 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 as a Public Utilities Regulatory Analyst II in the Division of Ratepayer Advocates, Electricity Planning & Policy Branch.

Q.3 Please describe your education and professional experience.
A.3 I received a Bachelor of Arts Degree in Political Economy of Industrial Societies from the University of California, Berkeley. I also possess a Master of Science Degree in Corporate Finance from SDA Bocconi School of Management located in Milan, Italy. I joined the Commission on January 3, 2012 in DRA's Electricity Planning and Policy Branch. In DRA, I have worked on Resource Adequacy, Flexible Capacity and Long-Term Planning and Procurement proceedings. At present, I am involved in ERRA Compliance and SONGS OII proceedings.

Q.4. What is your area of responsibility in this proceeding?
A.4 I am sponsoring Chapter 2 of DRA's testimony on PG&E's Nuclear and Hydro Utility Owned Generation and Chapter 4 of DRA's testimony on PG&E's QF Contract Administration, as it relates to the ERRA proceeding in A.13-02-023.

Q.5 Does this complete your testimony at this time?
A.5 Yes.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
RAVINDER MANGAT

Q.1. Please state your name and business address.

A.1. My name is Ravinder Mangat. 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 Regulatory Analyst in the Division of Ratepayer Advocates' (DRA) Electricity Planning and Policy Branch.

Q.3. Please describe your educational and professional experience?

A.3. In 1998, I received my Master's degree in Economics from University College London (UCL), with an emphasis on Applied Economics. Since joining DRA's Electricity Planning and Policy Branch in 2011 one of my primary tasks has been to review investor owned utilities' ERRA Forecasts and ERRA compliance submissions. Prior to working at CPUC I worked for an economic research consultancy based in Oakland, California, for five years. I have over 10 years of experience working as an economic and financial analyst in the private and public sectors.

Q.4. What is the scope of your responsibility in this proceeding?

A.4. I am responsible for preparing "Chapter 3: Utility Owned Generation: Fossil" and "Chapter 5: Least-cost dispatch.

Q.5. Does this complete your testimony at this time?

A.5. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
GRANT C. NOVACK

Q.1. Please state your name and address.

A.1. My name is Grant Novack. 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 Utility Financial Examiner III in the Division of Ratepayer Advocates.

Q.3. Please briefly describe your educational background and work experience.

A.3. I graduated from the University of Nevada, Las Vegas with a Bachelor of Science Degree in Business Administration in 1979. I joined the staff of the Commission in February 2003. I have 30 years auditing experience.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am responsible for the preparation of Chapters 6, 7, and 8.

Q.5. Does that complete your prepared testimony?

A.5. Yes, it does.

QUALIFICATIONS AND TESTIMONY DECLARATION
OF
COLIN RIZZO

Q.1 Please state your name and business address.

A.1 My name is Colin Rizzo. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

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 II in the Electricity Planning and Policy Branch of the Division of Ratepayer Advocates ("DRA").

Q.3 Please describe your education and professional experience.

A.3 I received a Bachelor of Science Degree in Journalism from California Polytechnic State University at San Luis Obispo in 2007. I received a Juris Doctorate from the University of the Pacific, McGeorge Law School in 2012. For the past three years, I have applied my policy and analytical skills to the following subject matter: (1) renewable energy resources; (2) combined heat and power settlement agreement; (3) greenhouse gas reduction programs; (4) long-term procurement policy and planning; and (5) distributive generation.

Q.4. What is your area of responsibility in this proceeding?

A.4 I am sponsoring Chapter 4 of DRA's testimony on PG&E's QF Contract Administration, as it relates to the ERRA proceeding in A.13-02-023.

Q.5 Does this complete your testimony at this time?

A.5 Yes.

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 Division of Ratepayer Advocates (DRA).

Q.3Briefly 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 DRA, 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 1 – Summary and Chapter 9 - Maximum Disallowance for Standard of Conduct 4 Violation

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.