Docket:	A.96-08-043
Commissioner:	
Admin. Law Judge:	

OFFICE OF RATEPAYER ADVOCATES
California Public Utilities Commission

MONITORING AND EVALUATION REPORT

November 1, 2010 through October 31, 2012

Pacific Gas and Electric Company's
Core Procurement Incentive Mechanism
Performance Results
(CPIM Year 18 and 19)

Application 96-08-043

San Francisco, California
June 05, 2014

TABLE OF CONTENTS

1	**SUMMARY AND RECOMMENDATIONS**	
1.1	Introduction and Summary	1-3
1.2	Background	1-3
1.3	Procurement and Sales	1-5
1.4	Financial Hedging Activities	1-6
1.5	Natural Gas Storage	1-7
1.6	Core Intrastate Capacity	1-8
1.7	Core Interstate Capacity	1-8
1.8	Review of CPIM Performance	1-9
1.9	Conclusion	1-10
2	**MONITORING AND EVALUATION AUDIT - Year 18**	
2.1	ORA's CPIM Reward Evaluation	2-1
2.2	Summary of Benchmark and Actual Costs	2-2
2.3	Review of Benchmark Commodity and Reservation Charges	2-3
2.4	Actual Natural Gas Costs and Reservation Charges	2-5
2.5	Natural Gas Storage Costs	2-5
2.6	Review of Purchase Gas Account (PGA)	2-9
2.7	Review of Core Pipeline Demand Charge Account (CPDCA)	2-10
2.8	Review of Miscellaneous Costs and Revenue	2-11
2.9	Examination of Hedging Costs	2-12
2.10	Review of Sales and Volume Transactions	2-14
2.11	Review of Volumetric Transport Costs	2-15
2.12	Review of Reservation Charges	2-16
2.13	Review of Benchmark Commodity Indices	2-19
2.14	Review of Fixed Storage and Transportation Costs	2-20
2.15	Utilization of Firm Interstate and Intrastate Pipeline Assets	2-21

TABLE OF CONTENTS

3	**MONITORING AND EVALUATION AUDIT - Year 19**	
3.1	ORA's CPIM Reward Evaluation	3-1
3.2	Summary of Benchmark and Actual Costs	3-3
3.3	Review of Benchmark Commodity and Reservation Charges	3-4
3.4	Actual Natural Gas Costs	3-5
3.5	Natural Gas Storage Costs	3-8
3.6	Review of Purchase Gas Account (PGA)	3-9
3.7	Review of Core Pipeline Demand Charge Account (CPDCA)	3-10
3.8	Review of Miscellaneous Costs and Revenues	3-11
3.9	Examination of Financial Derivatives	3-12
3.10	Review of Sales and Volume Transactions	3-14
3.11	Review of Volumetric Transport Costs	3-15
3.12	Review of Reservation Charges	3-16
3.13	Review of Benchmark Commodity Indices	3-18
3.14	Examination of Fixed Storage and Transportation Costs	3-19
3.15	Utilization of Firm Interstate and Intrastate Pipeline Assets	3-20

Appendix A - Exhibits for CPIM Report

Appendix B - Glossary

Appendix C - PG&E's Map of Natural Gas Pipelines

CHAPTER 1
SUMMARY AND RECOMMENDATIONS

1.1 Introduction and Summary

The Office of Ratepayer Advocates (ORA) performed an audit and evaluation of the data and documents submitted by Pacific Gas and Electric Company (PG&E) for its Core Procurement Incentive Mechanism (CPIM) Annual Performance Reports for the period November 1, 2010 through October 31, 2011 (Year 18) and the period November 1, 2011 through October 31, 2012 (Year 19). The details and results of ORA's review are presented in Chapter 2 and 3 of this ORA CPIM Monitoring and Evaluation (M&E) Report. ORA's evaluation of PG&E's recorded natural gas costs confirms that PG&E's costs were below the benchmark for periods Year 18 and 19, which resulted in ratepayer savings.

For Year 18, PG&E submitted its CPIM Performance Report on May 11, 2012 for the period November 1, 2010 through October 31, 2011. ORA's examination of PG&E's recorded costs for Year 18 shows that PG&E's costs were below the benchmark lower tolerance band, which results in a reward of $5,265,857 to PG&E's shareholders and a ratepayer benefit of $31,865,127.

For Year 19, PG&E submitted its CPIM Performance Report on May 14, 2013 for the period November 1, 2011 through October 31, 2012. ORA's examination of PG&E's recorded costs for Year 19 shows that PG&E's costs were below the benchmark lower tolerance band, which results in a reward of $5,062,766 to PG&E's shareholders and a ratepayer benefit of $27,344,679.

1.2 Background

The objective of the CPIM is to provide PG&E an incentive to reduce natural gas procurement costs. These costs include fixed transportation costs for Canadian, interstate, intrastate, and reservation costs. Other procurement costs include pipeline volumetric transportation costs and natural gas storage. The incentive mechanism is used as a ratemaking tool that is designed to increase efficiency in administering regulatory controls.

The CPIM structure establishes procedures on performance evaluation and reporting for PG&E's gas procurement costs. It sets forth guidelines for standard operating conditions and for special circumstances. The allowed monthly benchmark dollars are totaled over the annual CPIM period and compared to actual costs for the year to determine PG&E's performance. A tolerance band is constructed around the benchmark, and is defined as a range of costs considered reasonable. If PG&E's actual gas costs, as measured against the CPIM benchmark are between the upper and lower limit specifications for the tolerance band, there is no shareholder reward or penalty for the CPIM period. If actual costs fall outside the tolerance band, there will be sharing between ratepayers and PG&E shareholders of the gains or losses that occur outside the tolerance band. Detailed results of the tolerance band calculation are reported in Chapter 2 and 3 of this report.

The CPIM program was originally approved by the Commission in D.97-08-055 as set forth in the PG&E/ORA Post-1997 CPIM Agreement and PG&E's Supplemental Report describing the Post-1997 CPIM. The program established the framework to recover core gas procurement and transportation costs through rates. Since then, numerous changes and extensions have modified and refined the CPIM program structure and incentives.

In D.07-06-013, the Commission approved a settlement agreement between PG&E, ORA, The Utility Reform Network (TURN), and Aglet Consumer Alliance (Aglet). The settlement modified the CPIM to increase benefits to ratepayers in situations where natural gas purchases are less than the lower range of the tolerance band. The specific CPIM changes included are as follows:

- A 20/80 shareholder/ratepayer sharing of savings below the tolerance band, in contrast to the previous 25/75 shareholder/ratepayer sharing;
- The 2.5 Bcf un-sequenced storage withdrawal adjustment was eliminated and is to be included proportionately to the storage withdrawal sequence;

- Sequencing steps for San Juan Basin and AECO changed for natural gas purchases;
- Savings of five-percent (5%) from full tariff rates on pipeline or storage contracts are to offset CPIM gas costs;
- The index used to calculate the benchmark for daily swing purchases changed from the NGI daily Topock index to using the NGI daily PG&E CityGate index;
- For storage acquired via the Incremental Storage Capacity Request for Offers process, the daily benchmark will be adjusted to accommodate the incremental storage injection and withdrawal requirements to improve savings in gas costs.

In D.10-01-023, the Commission adopted a settlement agreement between PG&E, DRA, and TURN which addressed the treatment of hedging costs for PG&E. The key provisions of the adopted settlement call for the following treatment of hedging transactions:

- 80% of net realized gains or losses and associated transaction costs will be included in the CPIM Benchmark.
- 100% of the net hedging realized gains or losses and associated transaction costs will be included in the cost side of the CPIM calculation. Any gains will be subtracted and losses will be added to CPIM costs.
- The CPIM sharing mechanism is modified such that total shareholders earnings will be capped solely at 1.5 percent of annual gas commodity costs. The hard dollar cap of $25 million on shareholder gains was removed effective November 1, 2009.

1.3 Procurement and Sales

PG&E's actual gas purchase costs (including commodity, transportation, hedging, and storage) for Year 18 totaled $1,328,468,057 which was associated with a volume of 277,482,655 MMBtus (net of sales). For Year 19, PG&E's actual gas purchase costs totaled $969,406,810 which was associated with a volume of 262,597,252 MMBtus (net of sales).

PG&E utilized gas sales to help manage its assets and reduce gas costs. It sells gas supplies to comply with daily pipeline balancing requirements, to respond to changes in core loads, and to capture price arbitrage opportunities. For Year 18, PG&E reported total gas sales of $281,351,907 associated with 67,003,527 MMBtus. For Year 19, total sales were $153,057,884 associated with 50,534,827 MMBtus.

1.4 Financial Hedging Activities

Before CPIM Year 18, all derivative gains, losses and related transaction costs associated with PG&E's winter hedge plan were excluded from CPIM costs per D.07-06-013. These costs flowed directly to PG&E's retail customers. D.07-06-013 authorized PG&E under the settlement to place financial hedges on a rolling three-year basis via an Annual Plan filing. PG&E was required to file five Annual Plans beginning with the 2007/2008 winter season that authorized a hedge plan for the current winter season and the subsequent two winter seasons. In addition, the settlement created a Core Hedging Advisory Group where ORA, Aglet, TURN and PG&E met quarterly to discuss PG&E's Annual Plan, and related hedging operations. By April 1 of each year, PG&E is required to report financial results of its Annual Plan including total funds spent on hedging instruments, total losses and gains for each category of hedging instrument, amount of monthly natural gas supplies hedged, and the impact of hedging results on customer rates.[1]

Pursuant to D.10-01-023, PG&E remains responsible to manage hedges proactively to ensure stability in customer rates. This includes implementing controls and selecting appropriate hedging instruments to mitigate derivative risks. PG&E is also required to take proactive steps by adjusting its hedging positions in response to changing market conditions.

On January 25, 2010, the Commission approved D.10-01-023 and the associated Settlement Agreement which requires eighty percent (80%) of winter hedging gains and losses and related transaction costs to be included in the CPIM benchmark. Also, one hundred percent (100%) of winter hedging gains and losses and related transaction costs would be included in the CPIM actual commodity costs. These CPIM changes would be incorporated starting in CPIM Year 18.

For Year 18, the total cost of financial derivatives was $96,146,432. Total recorded hedge premiums and swaps excluded from CPIM were $91,668,580. These costs were comprised of $9,937,713 in option premium costs and $81,730,868 in financial swaps. The financial derivatives included in CPIM were $4,477,852 in option premium costs.

For Year 19, the total cost of financial derivatives was $69,142,711. The total hedging costs excluded from CPIM were $48,578,694 which comprised of $48,546,200 in financial swaps and $32,494 in fees. The financial derivatives included in CPIM were $20,564,017, which comprised of $8,760,879 in option premiums, $11,783,737 in financial swaps, and $19,401 in fees.

1.5 Natural Gas Storage

Under the CPIM, PG&E has a daily injection and withdrawal schedule. During CPIM Year 18, storage inventory injections were 33,172,676 MMBtus, and storage withdrawals were 31,325,146 MMBtus. Beginning inventory was reported at 31,905,476 MMBtus, and ending inventory shows 33,753,006 MMBtus, which is consistent with the required inventory of 33.5 MMdth.

For CPIM Year 19, storage inventory injections were 29,624,913 MMBtus, and storage withdrawals were 29,550,652 MMBtus. Beginning inventory was reported at 32,253,027 MMBtus, and ending inventory shows 33,827,267 MMBtus, which also complies with the required inventory of 33.5 MMdth.

---

[1] Settlement Agreement – Regarding PG&E Long-Term Core Hedge Program (A.06-05-007), the Core Procurement Incentive Mechanism (CPIM), and Transportation Capacity held on Behalf of Core Customers,

Pursuant to D.06-017-010 and D.07-06-013, PG&E is authorized to acquire incremental storage to meet a 1-day-in-10-year peak-planning standard for its core customers. The incremental storage costs are included in the benchmark and inventory schedules are adjusted by the amount of daily injections and withdrawals on a daily basis. This enables PG&E to track costs for the benchmark and adjust the amount of daily actual incremental natural gas injection and withdrawals.

Pursuant to D. 06-07-010, and modified by D.08-07-009, PG&E acquired additional incremental storage capacity for future winter season periods for 2011 through 2015. This capacity became effective in Year 18 for the purpose of injection activity.

On August 7, 2009, the Commission approved Advice Letter 3031-G, which authorized PG&E to acquire additional incremental storage capacity to improve its reliability during peak demand periods. These acquisition costs will be reported in CPIM Years 18 through 22.

A change of firm storage injection and withdrawal requirements used to calculate the CPIM benchmark was agreed to with a Memorandum of Understanding (MOU) between PG&E and ORA on October 19, 2009. These changes provide an updated profile of storage beginning in Year 17 when core storage will be adjusted for Core Transport Agents (CTAs) as stated in Tariff G-CT. This MOU will remain in effect until both parties agree to make changes.[2]

1.6 Core Intrastate Capacity

Pursuant to D.04-12-050, the Commission allowed the Core Procurement Department of PG&E to recover costs for firm reservation of intrastate backbone pipeline capacity. PG&E should not favor shareholder interests at the expense of core customer interests in the execution of the adopted CPIM.

December 15, 2006.

[2] CPIM - ORA and PG&E Memorandum of Understanding, dated October 19, 2009.

In the Gas Accord V Settlement, PG&E was allowed to retain existing quantities at Baja Path and eliminate Silverado capacity that expired on 04/30/2011 in CPIM Year 18.

1.7 Core Interstate Capacity

PG&E holds interstate capacity for the core on Trans-Canada NOVA Gas Transmission Ltd. (NGTL), Trans-Canada BC system Foothills Pipe Lines, Ltd. (Foothills), Trans-Canada Gas Transmission Northwest (GTN), El Paso Natural Gas Company (EPNG), Transwestern Pipeline Company (TW), and Kern River Gas Transmission Company (Kern River). During Year 18, PG&E's core interstate capacity holdings were approximately 619 MDth/d on NOVA, 611 MDth/d on the BC System, 610 MDth/d on GTN, 202 MDth/d on EPNG, and 177 MDth/d on TW.[3]

For Year 19, core interstate capacity was reported at approximately 370 MDth/d for NOVA, 366 MDth/d on the BC System, 360 MDth/d on GTN, 268 MDth/d on EPNG, 193 MDth/d on TW, 250 MDth/d on Ruby, and 50 MDth/d on Kern River[4]

Pursuant to D.04-09-022, the Commission authorized PG&E to seek pre-approval and expedited advice letter treatment for interstate capacity contracts that meet specified criteria. Prior to seeking pre-approval, PG&E is required to consult with ORA, TURN, and the Energy Division (ED) to obtain agreement.

Approved Advice Letter 3242-G, PG&E had two contract extensions for Foothills. The first contract was for 284,810 Dth/d and the second contract was for 81,384 Dth/d. These contracts terms were effective from November 1, 2012, through Oct 31, 2013.

In Year 19, pursuant to Advice Letter 3326-G, PG&E extended the two contracts on Foothills for 284,810 Dth/d and 81,384 Dth/d, effective November 1, 2013, through October 31, 2014. In addition to core interstate capacity, PG&E

---

[3] PG&E Annual Performance Report, Year 18, Table III.

[4] PG&E Annual Performance Report, Year 19, Table III.

executed one year contracts on El Paso for 66,000 Dth/d and Kern River for 50,033 Dth/d.

Through Advice Letter 3331-G, PG&E renewed the Transwestern contract for 142,970 Dth/d effective April 1, 2013 through March 31, 2015. The new updated capacity is reflected in Table 2-17 and Table 3-17.

1.8 Review of CPIM Performance

Table 1-1 below compares benchmark gas costs to actual costs of natural gas (including transportation and storage costs) in total dollars, as well as by volume, for the last two years starting from Year 18, as confirmed by ORA's examination of PG&E reports.

Table 1-1
Gas Cost Comparison

	CPIM Year 18	CPIM Year 19
Actual Gas Cost	$ 1,328,468,057	$ 969,406,810
Benchmark Gas Cost	$ 1,365,599,041	$ 1,001,814,255
Total Savings	$ 37,130,984	$ 32,407,445
Ratepayer Savings	$ 31,865,127	$ 27,344,679
Shareholder Reward	$ 5,265,857	$ 5,062,766
Average Actual Gas Cost ($/MMBtu)	$ 4.79	$ 3.69
Average Benchmark Cost ($/MMBtu)	$ 4.92	$ 3.82

1.9 Conclusion

Based on the foregoing, ORA recommends a shareholder reward to PG&E for Year 18 of $5,265,857, and Year 19 of $5,062,766 to be recovered through PG&E's Purchased Gas Account. ORA will continue monitoring and evaluating the CPIM and collaborate with PG&E and other parties to identify any modifications needed to enhance CPIM effectiveness.

CHAPTER 2

MONITORING AND EVALUATION AUDIT
Year 18

2.1 ORA's CPIM Reward Evaluation

Pacific Gas and Electric Company (PG&E) filed its Core Procurement Incentive Mechanism (CPIM) Performance Report, Year 18 Application (A.96-08-043), which reports on natural gas procurement results for the period from November 1, 2010 through October 31, 2011. ORA conducted a review and evaluation of PG&E's accompanying performance report. The results from this evaluation include working papers from our compilations, which are incorporated as exhibits in Appendix A. This report filing is in compliance with the Gas Accord Decision D.97-08-055, dated August 1, 1997, which approved the CPIM method for PG&E's recovery of core gas procurement and transportation costs.[5] On August 22, 2002, the Commission issued D.02-08-070, (Gas Accord II Decision), extending the initial Gas Accord market structure including the CPIM, through 2003. On December 18, 2003, the Commission issued D.03-12-061, extending the CPIM through Year 2005, or until a revised CPIM is adopted by the Commission. Pursuant to D.07-06-013, the Commission adopted a Settlement Agreement that address long-term hedging for PG&E's core customers, as well as, related CPIM modifications.

CPIM summarizes gas costs, tolerance band limit, and performance results that compare it to the benchmark. The CPIM benchmark consists of four components: a) fixed transportation costs which include Canadian, U.S. interstate, and California intrastate reservation costs; b) variable costs which include commodity costs, Canadian, U.S. interstate, and California intrastate pipeline fuel and volumetric capacity costs; c) storage costs for fixed reservation charges and variable costs; and

[5] In D.97-08-055 (approving the Gas Accord), the Commission approved a CPIM mechanism for core gas costs incurred after December 31, 1997. In this decision, the Commission ordered PG&E to file quarterly and annual reports on core procurement operations starting after completing one year of Gas Accord operations.

d) Hedging costs which included 80% of net realized gains or losses and associated transaction costs of winter hedges. The total cost of these four components would serve as the benchmark to compare to the actual costs.

The actual commodity costs of gas are measured annually against the benchmark and the calculated tolerance band. The benchmark is based on the prevailing published natural gas price indices for gas delivered from the border and PG&E's CityGate.

ORA's evaluation of PG&E's CPIM Year 18 performance in Table 2-1 shows benchmark commodity costs of $1,365,599,041 and PG&E's actual commodity cost is $1,328,468,057. The difference between the benchmark commodity cost and PG&E's actual commodity cost results in $37,130,984 of total savings in natural gas procurement costs. Results show the upper tolerance band benchmark (benchmark plus 2.0% of commodity benchmark plus reservation charges) is $1,387,202,439, and the lower tolerance band benchmark (benchmark minus 1.0% of commodity benchmark plus reservation charges) is $1,354,797,342.

The actual commodity cost of $1,328,468,057 is $37,130,984 less than the benchmark commodity cost of $1,365,599,041. This is below the CPIM benchmark, which reflects PG&E's gas savings performance. The lower limit of the tolerance band is used to calculate the ratepayers saving and shareholder reward. These results provide savings to be shared between PG&E customers and shareholders, see Table 2-1.

ORA's review shows PG&E's Year 18 savings below the lower tolerance band, and results in total savings of $26,329,285. Based on the CPIM, this saving is shared between ratepayers of $21,063,428 and a shareholder reward of $5,265,857. The total ratepayer savings is $31,865,127.

TABLE 2-1
Pacific Gas & Electric Company
Ratepayer Savings and Shareholder Award Calculation
CPIM 18
November 1, 2010 Through October 31, 2011

CPIM Reward Calculation	
Benchmark Commodity Cost	$ 1,365,599,041
Actual Commodity Cost	1,328,468,057
Under/(Over)	37,130,984
Upper Tolerance Band (Benchmark + 2% of Commodity Cost)	1,387,202,439
Lower Tolerance Band (Benchmark - 1% of Commodity Cost)	1,354,797,342
Lower Tolerance Band Less Actual Commodity Cost	26,329,285
Ratepayer Shared Savings (80%)	21,063,428
Shareholder Shared Savings (20%)	5,265,857
	$ 26,329,285
Total Ratepayer Savings	$ 31,865,127

2.2 Summary of Benchmark and Actual Costs

Table 2-2 shows the overall annual result of the actual commodity cost compared to the benchmark commodity cost of gas operation in CPIM Year 18.

ORA examined and reconciled all gas commodity costs, hedge costs, and transportation reservation charges that were reported in the CPIM Year 18 period. The natural gas sale and miscellaneous costs and revenues are only included in the actual costs as costs or credits depending on the result of natural gas operation. ORA's examination of PG&E's records for miscellaneous costs, winter hedge, reservation and transportation costs, and regulatory balancing accounts is performed to highlight variances in the reporting of gas costs. The following sections in this chapter provide a detailed review and breakdown of these related costs.

Table 2-2
Pacific Gas & Electric Company
Summary of Benchmark and Actual Costs
CPIM 18
November 1, 2010 Through October 31, 2011

	Actual	Benchmark	Difference
Purchased Natural Gas Cost	$ 1,346,680,441	$ 1,076,587,592	$ 270,092,849
Natural Gas Sales	$ (281,351,907)	$ -	$ (281,351,907)
Miscellaneous Costs and Revenues	$ (16,456,030)	$ -	$ (16,456,030)
Winter Hedge	$ 4,477,852	$ 3,582,282	$ 895,570
Reservation Charges*	$ 275,117,701	$ 285,429,167	$ (10,311,466)
Total Commodity Cost	$ 1,328,468,057	$ 1,365,599,041	$ (37,130,984)

* Reservation Charges included total of $220,598 in the rate refund and other charge

2.3 Review of Benchmark Gas Costs and Reservation Charges

The CPIM benchmark is based on published indices for natural gas commodity costs at PG&E's CityGate. This CPIM benchmark consists of three main components, the total gas purchase cost, 80% of winter hedging cost, and reservation charges. Table 2-3 provides a breakdown for each pipeline costs that represents PG&E's commodity costs for the period. For this period, total benchmark commodity costs, including purchased gas costs, winter hedging cost, reservation costs and other costs, are $1,365,599,041. The benchmark commodity costs are $1,076,587,592, and benchmark pipeline reservation charges of $285,429,167. Starting with CPIM Year 18, eighty percent of net realized gains or losses and associated transaction costs of the winter hedging transactions are included in the benchmark cost. The benchmark portion of the winter hedging program of PG&E is $3,582,282. There was a rate refund credit of $221,000 from El Paso Natural Gas Company and Kern River Gas Transmission that is included in the benchmark.

TABLE 2-3
Benchmark Commodity Costs and Reservation Charges
CPIM Year 18
November 1, 2010 Through October 31, 2011

		Market
Benchmark Purchased Gas Costs - by Pipelines:		**Benchmark**
California Firm	$	743,445
Kingsgate	$	12,364,833
San Juan	$	277,407,422
AECO	$	699,707,481
Topock Firm	$	35,459,982
CityGate As Available	$	50,904,429
Total Benchmark Gas Costs:	$	1,076,587,592
Hedging Cost		
80% of Winter Hedging Cost	$	3,582,282
Benchmark Reservation Charges:		
Foothills Pipelines Ltd	$	20,830,286
Nova Gas Transmission Ltd	$	44,424,159
Gas Transmission Northwest Corp	$	71,289,011
El Paso Natural Gas Company	$	22,926,705
Transwestern Pipeline Company	$	19,257,323
California Gas Transmission	$	105,167,101
Losdi Gas Storage, Inc.	$	1,755,180
Rate Refund	$	(221,000)
Other Charge (Credit)	$	402
Total Benchmark Reservation Charges:	$	285,429,167
Total Benchmark Commodity Costs:	$	1,365,599,041

Total Purchased Volume: 344,486,182 MMBtu

2.4 Actual Gas Costs and Reservation Charges

A review of actual costs for commodity purchases and reservation charges reported by PG&E is summarized in Table 2-4. On a monthly basis, PG&E would sell some of its un-used assets. The net sale is treated as a credit to the procurement cost. In addition to the calculation of actual commodity costs of CPIM Year 18, one hundred percent of winter hedging realized gain or losses and associated transaction costs are included in the actual. Reservation charges include intrastate and interstate charges for Trans-Canada-B.C. System, California Gas Transmission, El Paso Natural Gas Company, Lodi Gas Storage, Inc., Nova Gas Transmission, Ltd., Gas Transmission Northwest Corporation, and Transwestern Pipeline Company.[6] PG&E's net total actual commodity costs are $1,328,468,057, which include interstate and intrastate purchased gas costs of $1,048,872,504, winter hedging cost of $4,477,852, reservation charges for interstate and California intrastate capacity of $275,117,701, and adjustments of $220,598 for rate refund and other credits.

[6] PG&E Annual Performance Report, CPIM Year 18, dated May11, 2012.

TABLE 2-4
Summary of Actual Commodity Costs & Reservation Charges
CPIM Year 18
November 1, 2010 Through October 31, 2011

Actual Purchased Gas Costs - by Pipeline:		**Actual Costs**
CGT-Citygate	$	66,198,318
EPNG-Basin	$	234,498,442
EPNG-Topock	$	22,444,911
Kern River-Daggett	$	9,136,553
NGTL-AECO/NIT	$	820,416,847
GTNC-All	$	474,187
TW-Basin	$	153,580,151
TW-Topock	$	15,673,695
Volumetric Transportation Cost	$	24,257,337
Gas Sale	$	(281,351,907)
Miscellaneous Costs & Revenues	$	(16,456,030)
Total Purchased Gas Costs:	$	1,048,872,504
Hedging Costs		
100% Winter Hedging Cost	$	4,477,852
Actual Reservation Charges:		
Foothills Pipelines Ltd	$	20,830,286
Nova Gas Transmission Ltd	$	44,424,159
Gas Transmission North west Corp	$	71,289,011
El Paso Natural Gas Company	$	22,926,705
Transwestern Pipeline Company	$	19,257,323
California Gas Transmission	$	105,167,101
Losdi Gas Storage, Inc.	$	1,755,180
Discount Demand Charges	$	(454,924)
Capacity Release Revenue	$	(11,857,385)
Discounted/(Premium) Capacity Release	$	2,000,843
Rate Refund	$	(221,000)
Other Charges (Credits)	$	402
Total Reservation Charges:	$	275,117,701
Net Actual Commodity Costs:	$	1,328,468,057

2.5 Natural Gas Storage Costs

In accordance with D.06-07-010, a monthly distribution of winter storage withdrawals and summer storage injections is used in the calculation of the monthly benchmark purchase volumes. PG&E reports managing storage so that impacts to

CPIM metrics can be attained while ensuring adequate capacity is available for reliability. A schedule is used to establish daily benchmark allocations of injections and withdrawals and to ensure distributions are allocated evenly throughout the period. When it becomes necessary to balance portfolio supplies with core loads, PG&E will generally make exceptions from its planned schedules in order to meet interstate and intrastate pipeline tolerances, balancing rules, and most importantly, conservation of gas for storage and peak requirements.[7]

For the benchmark, the storage cost component includes volumetric storage charges as well as storage reservation costs at the as-billed rate for a) 33.5 MMdth of annual inventory, b) 115 to 207 Mdth per day of summer injection, and c) 970 to 1,253 Mdth per day of winter withdrawal capacity, which is adjusted for core aggregation elections.[8]

ORA's Exhibit 2-D4 shows total storage charges were $47,419,764, which include $45,690,264 paid to California Gas Transmission (CGT), and $1,729,500 to Lodi Gas Storage, Inc. In addition to storage costs, there was $333,335 for incremental storage cost for CGT during the reporting period, see Exhibit 2-D5 for details.

In Table 2-5, a summary of storage inventory shows the status of physical inventories (measured in MMBtus) for beginning and ending balances as of October 31, 2011. PG&E reported beginning storage inventory levels as of November 1, 2010 at 31,905,476 MMBtus and ending inventory as of October 31, 2011 at 33,753,006 MMBtus. At the CPIM period, injection and withdrawal levels show 33,172,676 MMBtus of injections, and 31,325,146 MMBtus of withdrawals. The reported balances are consistent with the required inventory levels of 33.5 MMdth.

[7] PG&E Annual Performance Report, CPIM Year 18, dated May 11, 2012.

[8] The actual ratemaking treatment of the core storage reservation provides for a fully bundled cost with no variable charge. However, for CPIM calculation purposes, a variable storage cost has been assumed in order to provide an appropriate economic incentive to use storage services efficiently.

TABLE 2-5 Pacific Gas and Electric Company Summary of Storage Inventory Injections and Withdrawals CPIM Year 18 November 1, 2010 through October 31, 2011				
Natural Gas Storage Providers	**Beginning Inventory 11/01/10 (MMBtus)**	**Injections**	**Withdrawals**	**Ending Inventory 10/31/11 (MMBtus)**
Pacific Gas & Electric	30,905,476	31,772,697	(30,425,146)	32,253,027
LODI Storage, Inc.	500,000	1,399,979	(400,000)	1,499,979
California Gas Transmission	500,000	0	(500,000)	0
Total Storage Inventory	31,905,476	33,172,676	(31,325,146)	33,753,006

2.6 Review of Purchase Gas Account (PGA)

PG&E submitted its reconciliation of its regulatory balancing account, Purchase Gas Account (PGA). For the reporting period, PG&E's accounting entries represent the amounts expected to be received from or refunded to its customers through authorized adjustments within a twelve-month period. The PGA shows the tracking of gas related costs and revenues for recovery. The under-or-over collected position of this account is dependent on seasonality and volatility in gas volumes. ORA examined reconciliation entries with related PG&E CPIM documentation to identify the nature and timeliness of these entries. Table 2-6 below shows net commodity costs of $1,049,251,988, with a $701 timing difference, which agrees with supporting documentation presented in PG&E’s Annual Performance Report, for actual natural gas purchases.

A sample test of purchase invoices were randomly selected in addition to the PGA audit. PG&E provided copies of supporting documents and purchase invoices for the purpose of the verification. Costs of these purchase invoices were traced to the monthly statement and then to the annual report. The selected purchase invoices reconciled with recorded amounts in the annual report.

TABLE 2-6
Pacific Gas and Electric Company
Purchase Gas Account Review
CPIM Year 18
November 1, 2010 through October 31, 2011

CPIM Purchase Costs	Commodity Purchases	Volumetric Transportation	Subtract True-up	Add True-up	Total CPIM
EPNG, Kern River, and Transwestern (Baja Path):					
Basin	$ 372,702,452	$ 2,116,941	$ -	$ -	$ 374,819,393
Transmission Line	$ 42,821,674	$ 8,765,818			$ 51,587,492
GTNC and NGTL (Redwood Path):					
Transmission Line	$ 745,886,807	$ 13,378,287			$ 759,265,094
CityGate (Mission Path)	$ (120,339,938)	$ 333,335			$ (120,006,603)
Sub-Total:	$ 1,041,070,995	$ 24,594,381	$ -	$ -	$ 1,065,665,376
Recorded in CGT Core Firm Storage		$ 7,500			$ 7,500
Misc. Revenues and Expenses	$ (14,002,775)	$ -			$ (14,002,775)
Lehman Bros. Settlement	$ (2,417,412)				$ (2,417,412)
Total Per CPIM	$ 1,024,650,808	$ 24,601,881	$ -	$ -	$ 1,049,252,689
Purchase Gas Account Adjustments:					
Acct 5500010	$ 374,939,452		$ 97,016	$ (2,110,080)	$ 372,926,388
Acct 5500021	$ 771,809,023		$ 659,762	$ 1,553,817	$ 774,022,602
Acct 5500041	$ (121,351,407)		$ (295,861)	$ 473,489	$ (121,173,779)
Acct 5500054		$ 5,443,676			$ 5,443,676
Acct 5500055		$ 19,257,630	$ (2,100)	$ (16,741)	$ 19,238,789
Acct 5500056		$ (13,387)			$ (13,387)
Demand Fees	$ 300,000				$ 300,000
EPNG Cash Out		$ 19,993			$ 19,993
Cochrane Revenues Per CPIM					
Gas Storage Sales to CTAs	$ (232,297)				$ (232,297)
CTA Mid-Year Storage Allocation	$ (1,280,220)				$ (1,280,220)
EPNG Overrun Charges	$ (1,577)				$ (1,577)
Recored in Acct 5500065		$ 1,800			$ 1,800
Total PGA:	1,024,182,974	24,709,712	458,817	(99,515)	1,049,251,988
Timing Differences:	$ 467,834	$ (107,831)	$ (458,817)	$ 99,515	$ 701

2.7 Review of Core Pipeline Demand Charge Account (CPDCA)

PG&E submitted its reconciliation for regulatory balancing account, Core Pipeline Demand Charge Account (CPDCA). This account is used to record costs associated with backbone transmission, interstate capacity, and Canadian capacity for core procurement. ORA reviewed PG&E documentation, which shows total charges by pipeline for the period to be $275,117,702.

Balance account entries consist of pipeline demand charges, firm storage costs, and pipeline transport charges. Table 2-7 shows total entries in the amount of $274,870,736, and timing differences of $381,316 are considered nominal.

Table 2-7
Pacific Gas and Electric Company
Review of CPDCA Balancing Account
CPIM Year 18
November 1, 2010 through October 31, 2011

Pipeline	Demand Charges	Subtract True-up	Add True-up	Total CPIM
Foothills Pipe Lines Ltd.	20,515,757	$-	$-	20,515,757
California Gas Transmission	55,888,000			55,888,000
Firm Storage Costs	45,697,764			45,697,764
El Paso Natural Gas	21,136,787			21,136,787
CGT Incremental Storage	-			-
Kern River Gas Transmission Company	(217,473)			(217,473)
Lodi Gas Storage	1,755,180			1,755,180
NOVA Gas Transmission	42,674,206			42,674,206
Gas Transmission N.W.	70,632,223			70,632,223
Transwestern Pipeline Company	17,035,258			17,035,258
Total Demand Charges:	$ 275,117,702	$ -	$ -	$ 275,117,702
SAP Journal Entries:				
Account 5500064 - Demand	133,349,923			133,349,923
Account 5500065 - Demand	94,552,088	(36,184)	(98,166)	94,417,738
Account 5500067 - Firm Storage	45,690,263	-	-	45,690,263
Account 5500055 - Lodi Gas Storage	1,755,180			1,755,180
Transwestern Pipeline Company	(454,924)			(454,924)
EPNG Cash Out (recorded in 5500055)	(19,993)			(19,993)
sge Storage Charge Recorded in Firm Storage in CI	-			-
Recorded in Reservation in CPIM	(1,800)			(1,800)
Prior Period Adjustments	-			-
Total CPDCA	$ 274,870,736	$ (36,184)	$ (98,166)	$ 274,736,386
Timing Difference	$ 246,966	$ 36,184	$ 98,166	$ 381,316

2.8 Review of Miscellaneous Costs and Revenues

Table 2-8 shows a summary of miscellaneous costs and credits that agree with reporting from PG&E's Annual Performance Report for the period. Results show total annual miscellaneous costs and revenues at $16,456,030. This amount consists of Broker Fees of $227,896, Cochrane Extraction Revenue of $14,618,193, EPNG Capacity Release credit of $1,998, Peaking Contract Demand Fees of $300,000, Lehman Bros Settlement of $2,465,147, Overrun and Lending Charges of $1,577, Parking and Lending Charges of $7,002, and Usage Storage Charge of $92,833. These revenues offset reported procurement costs and assist management in managing net costs that impact CPIM performance.

TABLE 2-8
Pacific Gas and Electric Company
Miscellaneous Costs and Revenues
CPIM Year 18
November 1, 2010 through October 31, 2011

Month Year	Broker Fees	Cochrane Extraction Revenue	EPNG Capacity Release	Peaking Contract Demand Fees	Lehman Bros Settlement	Overrun and Lending Charges	Parking and Lending Charges	Usage Storage Charge	Total Misc Charges
Nov-10	$ 17,595	$ (1,230,499)	$ -	$ 300,000	$ -	$ -	$ -	$ -	$ (912,904)
Dec-10	$ 21,860	$ (1,254,059)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,232,199)
Jan-11	$ 20,802	$ (1,288,565)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,267,763)
Feb-11	$ 17,009	$ (1,119,579)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,102,570)
Mar-11	$ 25,147	$ (1,389,595)	$ -	$ -	$ (2,465,147)	$ -	$ -	$ -	$ (3,829,595)
Apr-11	$ 17,276	$ (1,312,050)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,294,774)
May-11	$ 16,943	$ (1,362,229)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,345,286)
Jun-11	$ 20,372	$ (1,351,103)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,330,731)
Jul-11	$ 23,761	$ (1,025,128)	$ -	$ -	$ -	$ -	$ 2,190	$ 7,500	$ (991,677)
Aug-11	$ 14,908	$ (1,008,447)	$ -	$ -	$ -	$ -	$ 3,509	$ 56,333	$ (933,697)
Sep-11	$ 17,973	$ (1,011,088)	$ (1,998)	$ -	$ -	$ 1,577	$ 1,303	$ 29,000	$ (963,233)
Oct-11	$ 14,250	$ (1,265,851)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,251,601)
Totals:	$ 227,896	$ (14,618,193)	$ (1,998)	$ 300,000	$ (2,465,147)	$ 1,577	$ 7,002	$ 92,833	$ (16,456,030)

2.9 Examination of Hedging Costs

Pursuant to D.07-06-013, the Commission authorized PG&E's Annual Core Hedge Implementation Plan for 2008 for long term hedging for purchases of call options and swaps for a three-year period. This decision provided highlights for the long-term core hedge program for its requirements of reporting.

D.07-06-013 requires PG&E to report financial options and swaps under its hedging plan. The total hedge premiums and swap losses recorded and recovered from PG&E ratepayers for Year 18 were $96,146,432. The option premiums and financial swaps that were exempt from CPIM is $91,668,580. As shown in Table 2-9, PG&E reported hedging activity of option premiums paid of $9,937,713, and swap losses of $81,730,868, which are not included in CPIM Year 18 costs.

Table 2-9
Pacific Gas and Electric
CPIM Year 18
November 1, 2010 - October 31, 2011
Hedging Costs

	Inside CPIM	Outside CPIM	Total
Option Premiums	$ 4,477,852	$ 9,937,713	$ 14,415,565
Financial Swaps	$ -	$ 81,730,868	$ 81,730,868
Total Financial Derivatives	$ 4,477,852	$ 91,668,580	$ 96,146,432

The Commission in D.10-01-023, adopted January 25, 2010, approved a policy incorporating winter hedging transactions into CPIM. The winter hedging transactions executed on or after November 1, 2009 would be included into PG&E's CPIM calculation beginning on or after November 1, 2010. CPIM Year 18 was the first year to include the winter hedge costs and this change adopted in future CPIM calculations. The financial results for all hedges executed for Winter 2010-2011 within CPIM are summarized in the Table 2-10. The total cost of financial hedging is $4,477,852.

Table 2-10
Pacific Gas and Electric
CPIM Year 18
November 1, 2010 - October 31, 2011
Actual Winter Hedge Costs

Month	Option Premiums	Option and F/F Swap Settlements	Total
Nov-10	$ -	$ -	$ -
Dec-10	$ 1,542,371	$ -	$ 1,542,371
Jan-11	$ 1,542,371	$ -	$ 1,542,371
Feb-11	$ 1,393,110	$ -	$ 1,393,110
Mar-11	$ -	$ -	$ -
Apr-11	$ -	$ -	$ -
May-11	$ -	$ -	$ -
Jun-11	$ -	$ -	$ -
Jul-11	$ -	$ -	$ -
Aug-11	$ -	$ -	$ -
Sep-11	$ -	$ -	$ -
Oct-11	$ -	$ -	$ -
Total	$ 4,477,852	$ -	$ 4,477,852

2.10 Review of Sales and Volume Transactions

Table 2-11 shows PG&E total sales of $281,351,907, and reported volumes of 67,003,527 MMBtus. A breakdown by pipeline shows sales for CGT CityGate of $186,538,256, EPNG-Basin of $11,946,315, EPNG-Topock of $4,370,341, Kern River-Daggett of $252,990, NGTL-AECO/NIT of $5,961,810, GTNC-All of $69,042,418, TW-Basin of $3,227,024, and TW-Topock of $12,753. The same period sales volume for CGT CityGate showed 43,353,064 MMBtus, EPNG-Basin of 2,759,826 MMBtus, EPNG-Topock of 1,221,071 MMBtus, Kern River-Daggett of 62,507 MMBtus, NGTL-AECO/NIT of 1,662,187 MMBtus, GTNC-All of 17,214,136 MMBtus, TW-Basin of 727,736 MMBtus, and TW-Topock of 3,000 MMBtus.

TABLE 2-11 Pacific Gas and Electric Company Actual Sales and Volume CPIM Year 18 November 1, 2010 through October 31, 2011			
Sales by Pipeline:	**Volume (MMBtus)**		**$ Dollars**
CGT - Citygate	(43,353,064)	$	(186,538,256)
EPNG - Basin	(2,759,826)	$	(11,946,315)
EPNG -Topock	(1,221,071)	$	(4,370,341)
Kern River - Daggett	(62,507)	$	(252,990)
NGTL - AECO/NIT	(1,662,187)	$	(5,961,810)
GTNC - All	(17,214,136)	$	(69,042,418)
TW - Basin	(727,736)	$	(3,227,024)
TW - Topock	(3,000)	$	(12,753)
Total	(67,003,527)	$	(281,351,907)

2.11 Review of Volumetric Transport Costs

Table 2-12 provides a summary of PG&E's reported volumetric transportation costs by pipeline. Trends in transport activity are consistent with purchase and sales transactions. The total volumetric transport costs were $24,257,337. In addition, costs were broken down by pipeline to identify changes: CGT-Baja reported $8,765,619 in costs, CGT-Redwood $10,856,933, EPNG-Basin $1,617,403, NGTL-AECO/NIT $59,500, GTNC-All $2,461,853, and Transwestern-Basin $496,029. These costs are included in the CPIM and are part of the reconciliation of the PGA balancing account.

TABLE 2-12 Pacific Gas and Electric Company Commodity Volumetric Transport Costs CPIM Year 18 November 1, 2010 through October 31, 2011		
CGT - Baja	$	8,765,619
CGT - Redwood	$	10,856,933
EPNG - Basin	$	1,617,403
NGTL - AECO/NIT	$	59,500
GTNC - All	$	2,461,853
TW - Basin	$	496,029
Total Volumetric Transport Costs:	$	24,257,337

2.12 Review of Reservation Charges

ORA completed a reconciliation of the benchmark to actual reservation charges reported in PG&E's Annual Performance Report for subject period to identify any variances. The results show no discrepancies. The reconciliation accounts for actual reservation charges were $275,117,701, and adjustments to this amount were for discounted demand charges of $454,924, capacity release revenue of $11,857,385, discount capacity release of $2,000,843, storage cost of $47,778,779, and other adjustments of $220,598.

Table 2-13 provides a summary of adjustments that were offset against the benchmark. Net results agree with reported actual reservations of $275,117,701.

TABLE 2-13
Pacific Gas and Electric Company
Reconciliation of Reservation Charges
CPIM Year 18
November 1, 2010 through October 31, 2011

				Benchmark Demand Charges:
Actual Demand Charges by Pipeline System:				
Canadian			**$**	**237,870,986**
Foothills Pipelines Ltd.		20,830,286		
Nova Gas Transmission Ltd.		44,424,159		
Canadian Subtotal	$	65,254,445		
Interstate				
Gas Transmission Northwest Corporation		71,289,011		
El Paso Natural Gas Company		22,926,705		
Transwestern Pipeline Company		19,257,323		
Interstate Subtotal	$	113,473,039		
Intrastate				
California Gas Transmission Baja		32,481,562		
California Gas Transmission Redwood		26,643,436		
California Gas Transmission Silverdo		18,504		
Intrastate Subtotal	$	59,143,502		
Total Actual Demand Charges:	$	237,870,986	$	237,870,986
Discount Demand Charges:				
El Paso Natural Gas Company		(372,118)		
Transwesten Pipeline Company		(82,806)		
Demand Charge Discount Subtotal:	$	(454,924)	$	-
Capacity Release Revenue:				
Canadian Pipeline		(2,813,110)		
Interstate Pipeline		(4,210,322)		
Intrastate		(4,833,953)		
Total Capacity Release Revenue:	$	(11,857,385)	$	-
Discounted (Premium) Capacity Release:				
Canadian Pipelines		748,226		
Intrastate Pipelines		1,252,617		
Total Discounted (Premium) Capacity Release:	$	2,000,843	$	-
Storage Cost:				
California Gas Transmission Firm Storage		46,023,599		
Lodi Gas Storage, Inc.		1,755,180		
Storage Cost Subtotal:	$	47,778,779	$	47,778,779
Other Adjustments:				
Refund		(221,000)		
Others		402		
Total Other Adjustments:	$	(220,598)	$	(220,598)
Reconciliation of Reservation Charges:	**$**	**275,117,701**	**$**	**285,429,167**

Table 2-14, is reconciliation of capacity release revenues. It shows the breakdown capacity release revenue and costs by pipelines. The total capacity release revenue reconciled.

TABLE 2-14
Pacific Gas and Electric Company
Reconciliation of Capacity Release Revenue
CPIM Year 18
November 1, 2010 through October 31, 2011

Capacity Release Revenue			
Canadian			
Foothills Pipelines Ltd.			(864,114)
Nova Gas Transmission Ltd.			(1,948,996)
	Canadian Subtotal:	$	(2,813,110)
Interstate			
Gas Transmission Northwest Corporation			(656,788)
El Paso Natural Gas Company			(1,414,275)
Transwestern Pipeline Company			(2,139,259)
	Interstate Subtotal:	$	(4,210,322)
Intrastate			
California Gas Transmission Baja			(3,462,668)
California Gas Transmission Redwood			(1,352,781)
California Gas Transmission Silverdo			(18,504)
	Intrastate Subtotal:	$	(4,833,953)
	Total Capacity Release Revenue:	$	(11,857,385)
Discounted (Premium) Capacity Release:			
Canadian			
Foothills Pipelines Ltd.			549,183
Nova Gas Transmission Ltd.			199,043
	Canadian Subtotal:	$	748,226
Intrastate			
California Gas Transmission Baja			1,923,432
California Gas Transmission Redwood			(671,219)
California Gas Transmission Silverdo			404
	Intrastate Subtotal:	$	1,252,617
	Total Discounted (Premium) Capacity Release:	$	1,496,452

2.13 Review of Benchmark Commodity Indices

Table 2-15 provides a summary of PG&E's CityGate indices used to calculate the benchmark of monthly commodity costs. These indices are reported to *Natural Gas Intelligence*, which publishes them in their gas price index. As such, these indices were applied to the CityGate benchmark volume reported to determine the commodity benchmark costs. ORA compilations show the commodity benchmark cost of $1,076,587,592, plus winter hedging cost of $3,582,282, and the benchmark reservation charges of $285,429,167 results in the total market benchmark costs for Year 18 of $1,365,599,041.

The Canadian benchmark commodity indices are established using the exchange rates in effect when the indices are issued prior to the availability of closing currency exchange rates. However, the final indices, which determine the actual gas supply prices, reflect closing exchange rates.

For Year 18, PG&E's gas operations apply a pipeline sequencing methodology for purposes of purchasing gas at the lowest cost. However, PG&E has the discretion to change the sequence in pipeline selection at any time in order to meet reliability requirements.

Publishers of industry newsletters such as *Platt's*, and *Natural Gas Intelligence* take surveys of the price of transactions at a hub or city-gate where natural gas is sold or delivered. The surveyed prices are calculated into an average, which is reported as an index of those prices. These index prices are used to base the price of gas (spot price) at the hub, city-gate, or a specified location.

TABLE 2-15 Pacific Gas and Electric Company PG&E City Gate Indices CPIM Year 18 November 1, 2010 through October 31, 2011					
Month Year	**California Topock (Firm)**	**Kingsgate**	**San Juan**	**AECO**	**(End of Month) PG&E CityGate NGI Daily**
Nov-10	3.252800	3.820963	3.199990	3.495527	4.78
Dec-10	4.419129	4.329225	4.385128	3.998072	4.35
Jan-11	4.335214	4.438540	4.102600	4.095449	4.26
Feb-11	4.355436	4.503575	4.330634	4.157846	4.06
Mar-11	3.961099	4.178775	3.895297	3.828916	4.42
Apr-11	4.325103	4.363624	4.216617	4.005694	4.52
May-11	4.380235	4.388830	4.253436	4.039248	4.61
Jun-11	4.380235	4.486163	4.263770	4.139531	4.64
Jul-11	4.551606	4.711300	4.315439	4.352762	4.54
Aug-11	4.581848	4.283632	4.356774	3.935567	4.22
Sep-11	4.128219	3.989926	3.953755	3.661907	4.10
Oct-11	4.037494	4.171739	3.726310	3.838815	3.85

2.14 Examination of Fixed Storage and Transportation Costs

PG&E reported its benchmark reservation (demand) and fixed storage charges. Based on this report, ORA reviewed the costs and identified changes in activity from the prior year report. The total transportation and storage costs are $285,649,765, which consisted of the Canadian demand charges of $65,254,445, U.S. interstate pipeline reservation costs of $113,473,039, California intrastate pipeline costs of $59,143,502, and intrastate fixed and incremental storage costs of $47,778,779. Table 2-16 provides a summary of these costs.

TABLE 2-16
Pacifc Gas and Electric Company
Summary of Fixed Transport and Storage Costs
CPIM Year 18
November 1, 2010 through October 31, 2011

Benchmark Demand Charges		
Canadian		
Foothills Pipelines Ltd.		20,830,286
Nova Gas Transmission Ltd.		44,424,159
	Canadian Subtotal	$ 65,254,445
Interstate		
Gas Transmission Northwest Corporation		71,289,011
El Paso Natural Gas Company		22,926,705
Transwestern Pipeline Company		19,257,323
	Interstate Subtotal	$ 113,473,039
Intrastate		
California Gas Transmission Baja		32,481,562
California Gas Transmission Redwood		26,643,436
California Gas Transmission Silverdo		18,504
	Intrastate Subtotal	$ 59,143,502
	Total Demand Charges	**$ 237,870,986**
CA Intrastate Storage Costs:		
California Gas Transmission Firm Storage		
Firm Storage Cost		45,690,264
Incremental Storage		333,335
Lodi Gas Storage, Inc.		
Demand Charge		1,729,500
Injection/Withdrawal Charge		25,680
Total CA Storage Costs:		$ 47,778,779
Total Transportation & Storage Costs:		$ 285,649,765

2.15 Utilization of Firm Interstate and Intrastate Pipeline Assets

PG&E has short and long term contracts for purchases of natural gas resources transported via Canadian, U.S. interstate and California intrastate pipeline systems to meet core gas demand. During Year 18, PG&E transported these resources using firm transportation contracts. Table 2-17 shows PG&E's estimated utilization for the period.

PG&E estimates utilization proportionally based on capacity available to transport supplies and/or releases to other parties. To benefit core users, PG&E was authorized to increase the annual Baja Path core capacity and decrease capacity allocated to the Silverado Path. Increasing the Baja Path capacity encourages purchases of natural gas where prices are deemed to be more competitive, as well as matching the upstream firm capacity on the southwest interstate pipelines.[9] Additionally, PG&E is authorized to recover the costs associated with its Canadian and US interstate capacity through approval procedures specified in D.04-09-022.[10]

Pursuant to D.07-07-002, PG&E can also allocate firm intrastate capacity and recover associated costs. In the CPIM Year 19, PG&E added the Ruby pipeline to PG&E's core supply portfolio effective November 1, 2011. The Ruby pipeline provides contracted quantities of 250,000 Dth/d.[11]

---

[9] D.07-07-002, Opinion Regarding the Request to Change the Allocations of Firm Backbone Pipeline Capacity and Related Charges, p. 6.

[10] D.04-09-022, Rulemaking to Establish Policies and Rules to Ensure Reliable Long Term Supplies of Natural Gas to California.

[11] PG&E's Core Procurement Incentive Mechanism Year 18.

Pacific Gas and Electric Company
Core Gas Supply - Utilization of Interstate, Intrastate and Canadian Pipeline Assets
CPIM Year 18
November 1, 2010 through October 31, 2011

Pipeline Capacity:	**Quantity (Dth/d)**	**Contract Expiration Date**	**Utilization Rate**
TransCanada Pipelines:			
NOVA	249,401	10/31/11	
	287,745	10/31/16	
	82,223	10/31/20	
Total NOVA:	619,369		100%
Foothills-BC System	244,860	10/31/11	
	284,810	10/31/13	
	81,384	10/31/13	
Total Foothills-BC System:	611,054		100%
Interstate Pipelines:			
Gas Transmission Northwest	250,000	10/31/11	
	279,968	10/31/16	
	80,000	10/31/20	
Total Gas Transmission Northwest:	609,968		98%
El Paso Natural Gas	116,035	06/30/12	
	85,739	06/30/13	
Total El Paso Natural Gas:	201,774		89%
Transwestern Pipeline Co.	150,000	03/31/13	
Seasonal 10-11 (Dec-Feb.)	26,720	02/28/11	
Total Transwestern Pipeline Co:	176,720		98%
Intrastate Pipelines:			
Silverado Path	1,000	04/30/11	100%
Redwood Path	608,766	No expiration	100%
Baja Path	348,000	No expiration	
Seasonal (Dec-Feb)	321,000	No expiration	
Total Baja Path Capacity:	669,000		86%

CHAPTER 3
MONITORING AND EVALUATION AUDIT
YEAR 19

3.1 ORA's CPIM Reward Evaluation

Pacific Gas and Electric Company (PG&E) filed its Core Procurement Incentive Mechanism (CPIM) Performance Report, Year 19 Application (A.96-08-043), which reports on natural gas procurement results for the period from November 1, 2011 through October 31, 2012. ORA conducted a review and evaluation of PG&E's accompanying performance report. The results from this evaluation include working papers from our compilations, which are incorporated as exhibits in Appendix A. This report filing is in compliance with the Gas Accord Decision D.97-08-055, dated August 1, 1997, which approved the CPIM method for PG&E's recovery of core gas procurement and transportation costs.[12] On August 22, 2002, the Commission issued D.02-08-070, (Gas Accord II Decision), extending the initial Gas Accord market structure including the CPIM, through 2003. On December 18, 2003, the Commission issued D.03-12-061, extending the CPIM through Year 2005, or until a revised CPIM is adopted by the Commission. Pursuant to D.07-06-013, the Commission adopted a Settlement Agreement that address long-term hedging for PG&E's core customers, as well as, related CPIM modifications.

CPIM summarizes gas costs, tolerance band limit, and performance results that compare actual costs to the benchmark. The CPIM benchmark consists of four components: a) fixed transportation costs which include Canadian, U.S. interstate, and California intrastate reservation costs; b) variable costs which include commodity costs, Canadian, U.S. interstate, and California intrastate pipeline fuel and volumetric capacity costs; c) storage costs for fixed reservation charges and variable costs; and d) Hedging costs which included 80% of net realized gains or losses and associated

[12] In D.97-08-055 (approving the Gas Accord), the Commission approved a CPIM mechanism for core gas costs incurred after December 31, 1997. In this decision, the Commission ordered PG&E to file quarterly and annual reports on core procurement operations starting after completion of one year of Gas Accord operations.

transaction costs of winter hedges. The total cost of these four components serve as the benchmark to compare to the actual costs.

The actual commodity costs of gas are measured annually against the benchmark and the calculated tolerance band. The benchmark is based on the prevailing published natural gas price indices for gas delivered from the border and PG&E’s CityGate.

ORA’s evaluation of PG&E's CPIM Year 19 performance in Table 3-1 shows benchmark commodity costs of $1,001,814,255 and PG&E’s actual commodity cost is $969,406,810. The difference between the benchmark commodity cost and PG&E’s actual commodity cost results in $32,407,445 of total natural gas procurement savings. Results show the upper tolerance band benchmark (benchmark plus 2.0% of commodity benchmark plus reservation charges) is $1,016,001,485, and the lower tolerance band benchmark (benchmark minus 1.0% of commodity benchmark plus reservation charges) is $994,720,639.

The actual commodity cost of $969,406,810 is $32,407,445 less than benchmark commodity cost of $1,001,814,255. This is below the CPIM benchmark, which reflects PG&E's gas savings performance. The lower limit of the tolerance band is used to calculate the ratepayers saving and shareholder reward. These results provide savings to be shared between PG&E customers and shareholders, see Table 3-1.

ORA's review shows PG&E’s Year 19 savings below the lower tolerance band, and results in total savings of $25,313,829. Based on the CPIM, this saving is shared between ratepayers of $20,251,063 and a shareholder reward of $5,062,766. The total ratepayer savings is $27,344,679.

TABLE 3-1
Pacific Gas & Electric Company
Ratepayer Savings and Shareholder Award Calculation
CPIM 19
November 1, 2011 Through October 31, 2012

CPIM Reward Calculation	
Benchmark Commodity Cost	$ 1,001,814,255
Actual Commodity Cost	969,406,810
Under/(Over)	32,407,445
Upper Tolerance Band (Benchmark + 2% of Commodity Cost)	1,016,001,485
Lower Tolerance Band (Benchmark - 1% of Commodity Cost)	994,720,639
Lower Tolerance Band Less Actual Commodity Cost	25,313,829
Ratepayer Shared Savings (80%)	20,251,063
Shareholder Shared Savings (20%)	5,062,766
	$ 25,313,829
Total Ratepayer Savings	$ 27,344,679

3.2 Summary of Benchmark and Actual Costs

Table 3-2 shows the overall annual result of the actual commodity cost compared to the benchmark commodity cost of gas operation in CPIM Year 19.

ORA examined and reconciled all gas commodity costs, hedge costs, and transportation reservation charges that were reported in the CPIM Year 19 period. The natural gas sale and miscellaneous costs and revenues only included in the actual costs as costs or credits depending on the result of natural gas operation. ORA's examination of PG&E's records for miscellaneous costs, winter hedge, reservation and transportation costs, and regulatory balancing accounts is performed to highlight variances in the reporting of gas costs. The following sections in this chapter will provide a detailed review and breakdown of these related costs.

Table 3-2
Pacific Gas & Electric Company
Summary of Benchmark and Actual Costs
CPIM 19
November 1, 2011 Through October 31, 2012

	Actual	Benchmark	Difference
Purchased Natural Gas Cost	$ 830,079,074	$ 693,116,302	$ 136,962,772
Natural Gas Sales	$ (153,057,884)	$ -	$ (153,057,884)
Miscellaneous Costs and Revenues	$ (9,839,300)	$ -	$ (9,839,300)
Hedge Cost	$ 20,564,017	$ 16,245,301	$ 4,318,716
Reservation Charges	$ 281,660,903	$ 292,452,652	$ (10,791,749)
Total Commodity Cost	$ 969,406,810	$ 1,001,814,255	$ (32,407,445)

3.3 Review of Benchmark Commodity and Reservation (Demand) Charges

The CPIM benchmark is based on published indices for natural gas commodity costs at PG&E's CityGate. This CPIM benchmark consists of three main components, the total gas purchase cost, 80% of winter hedging cost, and reservation charges. Table 3-3 provides a breakdown for each pipeline costs that represent PG&E's commodity costs for the period. For this period, total benchmark commodity costs, including purchased gas costs, winter hedging cost, reservation costs and other costs, are $1,001,814,255. The benchmark commodity costs are $693,116,302; the benchmark winter hedge costs are $16,245,301 and benchmark pipeline reservation charges are $292,452,652.

TABLE 3-3
Benchmark Commodity Costs and Reservation Charges
CPIM Year 19
November 1, 2011 Through October 31, 2012

		Market Benchmark
Benchmark Purchased Gas Costs - by Pipelines:		
Ruby Roockies	$	143,034,677
AECO	$	298,781,544
San Juan	$	205,707,302
Kingsgate	$	547,113
Kern River	$	16,571,561
Topock	$	13,485,177
PG&E Citygate	$	14,988,928
Total Benchmark Gas Costs:	$	693,116,302
Hedging Cost		
80% of Winter Hedging Cost	$	16,245,301
Benchmark Reservation Charges:		
Foothills Pipelines Ltd	$	12,969,045
Nova Gas Transmission Ltd	$	23,110,844
Gas Transmission Northwest Corp	$	44,447,602
El Paso Natural Gas Company	$	21,045,908
Kern River Gas Transmission	$	1,692,656
Ruby Pipeline	$	61,134,526
Transwestern Pipeline Company	$	18,548,934
California Gas Transmission	$	58,063,182
CGT-Storage	$	49,095,955
Losdi Gas Storage, Inc.	$	2,344,000
Total Benchmark Reservation Charges:	$	292,452,652
Total Benchmark Commodity Costs:	$	1,001,814,255

3.4 Actual Natural Gas Costs

A review of actual costs for commodity purchases and reservation charges reported by PG&E is summarized in Table 3-4. On a monthly basis, PG&E would sell some of its un-used assets. The net sale is treated as a credit to the procurement cost. In addition to the calculation of actual commodity costs of CPIM Year 19, one hundred percent of winter hedging realized gain or losses and associated transaction costs are included in the actual. Reservation charges include intrastate and interstate charges for Trans-Canada-B.C. System, California Gas Transmission, El Paso Natural Gas

Company, Lodi Gas Storage, Inc., Ruby Pipeline LLC, Kern River Gas Transmission, Nova Gas Transmission, Ltd., Gas Transmission Northwest Corporation, and Transwestern Pipeline Company.[13]

PG&E's net total actual commodity costs are $969,406,810, which include interstate and intrastate purchased gas costs of $677,181,890, winter hedging cost of $20,564,017, reservation charges for interstate and California intrastate capacity of $281,660,903.

[13] PG&E Annual Performance Report, CPIM Year 19, dated May17, 2013.

TABLE 3-4
Summary of Actual Commodity Costs & Reservation Charges
CPIM Year 19
November 1, 2011 Through October 31, 2012

Actual Purchased Gas Costs - by Pipeline:		**Actual Costs**
CGT-Citygate	$	11,881,081
EPNG-Basin	$	153,143,126
EPNG-Topock	$	8,536,939
Kern River-Daggett	$	10,766,334
Kern River-Opal	$	2,936,683
NGTL-AECO/NIT	$	322,225,165
GTNC-All	$	7,047,107
Ruby Pipeline	$	188,079,503
TW-Basin	$	86,686,557
TW-Topock	$	11,119,113
Volumetric Transportation Cost	$	27,657,466
Gas Sale	$	(153,057,884)
Miscellaneous Costs & Revenues	$	(9,839,300)
Total Purchased Gas Costs:	$	667,181,890
Hedging Costs		
100% Winter Hedging Cost	$	20,564,017
Actual Reservation Charges:		
Foothills Pipelines Ltd	$	12,969,045
Nova Gas Transmission Ltd	$	23,110,844
Gas Transmission North west Corp	$	44,447,602
El Paso Natural Gas Company	$	21,045,908
Kern River Gas Transmission	$	1,692,656
Ruby Pipeline	$	61,134,526
Transwestern Pipeline Company	$	18,548,934
California Gas Transmission	$	58,063,182
CGT-Storage	$	49,095,955
Losdi Gas Storage, Inc.	$	2,344,000
Discount Demand Charges	$	(665,268)
Capacity Release Revenue	$	(12,075,415)
Discounted/(Premium) Capacity Release	$	1,948,934
Total Reservation Charges:	$	281,660,903
Net Actual Commodity Costs:	$	969,406,810

3.5 Natural Gas Storage Costs

In accordance with D.06-07-010, a monthly distribution of winter storage withdrawals and summer storage injections is used in the calculation of the monthly benchmark purchase volumes. PG&E reports managing storage so that impacts to CPIM metrics can be attained while ensuring adequate capacity is available for reliability. A schedule is used to establish daily benchmark allocations of injections and withdrawals and to ensure distributions are allocated evenly throughout the period. When it becomes necessary to balance portfolio supplies with core loads, PG&E will generally make exceptions from its planned schedules in order to meet interstate and intrastate pipeline tolerances, balancing rules, and most importantly, conservation of gas for storage and peak requirements.[14]

For the benchmark, the storage cost component includes volumetric storage charges as well as storage reservation costs at the as-billed rate for a) 33.5 MMdth of annual inventory, b) 115 to 207 Mdth per day of summer injection, and c) 970 to 1,253 Mdth per day of winter withdrawal capacity, which is adjusted for core aggregation elections.[15]

ORA's Exhibit 3-D4 show total storage charges were $51,417,955, which include $49,095,955 paid to California Gas Transmission (CGT), and $2,322,000 to Lodi Gas Storage, Inc. In addition to storage costs, there was injection and withdrawal cost of $22,000 for Lodi Gas storage during the reporting period, see Exhibit 3-D5 for details.

In Table 3-5, a summary of storage inventory shows the status of physical inventories (measured in MMBtus) for beginning and ending balances as of October 31, 2012. PG&E reported beginning storage inventory levels as of November 1, 2011 at 33,753,006 MMBtus and ending inventory as of October 31, 2012 at 33,827,267 MMBtus. In this CPIM period, injection and withdrawal levels show 29,624,913 MMBtus of injections, and 29,550,652 MMBtus of withdrawals. The reported balances are consistent with the required inventory levels of 33.5 MMdth.

---

[14] PG&E Annual Performance Report, CPIM Year 19, dated May 17, 2013.

[15] The actual ratemaking treatment of the core storage reservation provides for a fully bundled cost with no variable charge. However, for CPIM calculation purposes, a variable storage cost has been assumed in order to provide an appropriate economic incentive to use storage services efficiently.

TABLE 3-5
Pacific Gas and Electric Company
Summary of Storage Inventory Injections and Withdrawals
CPIM Year 19
November 1, 2011 through October 31, 2012

Natural Gas Storage Providers	Beginning Inventory 11/01/11 (MMBtus)	Injections	Withdrawals	Ending Inventory 10/31/12 (MMBtus)
Pacific Gas & Electric	32,253,027	28,524,892	(28,450,652)	32,327,267
LODI Storage, Inc.	1,499,979	1,100,021	(1,100,000)	1,500,000
California Gas Transmission	0	0	0	0
Total Storage Inventory	33,753,006	29,624,913	(29,550,652)	33,827,267

3.6 Review of Purchase Gas Account (PGA)

PG&E submitted its reconciliation of its regulatory balancing account, Purchase Gas Account (PGA). For the reporting period, PG&E’s accounting entries represent amounts expected to be received from or refunded to PG&E's customers through authorized adjustments within a twelve-month period. The PGA shows the tracking of gas related costs and revenues for recovery. The under-or-over collected position of this account is dependent on seasonality and volatility in gas volumes. Table 3-6 below shows net commodity costs of $667,326,576, which also agrees with supporting documentation presented in PG&E’s Performance Report, for actual natural gas purchases.

A sample of purchase invoices were randomly selected in addition to the PGA audit. PG&E provided copies of supporting documents and purchase invoices for the purpose of the verification. Costs of these purchase invoices were traced to the monthly statement and then to the annual report. The selected purchase invoices reconciled with recorded amounts in the annual report.

TABLE 3-6
Pacific Gas and Electric Company
Purchase Gas Account Review
CPIM Year 19
November 1, 2011 through October 31, 2012

CPIM Purchase Costs	Commodity Purchases	Volumetric Transportation	Subtract True-up	Add True-up	Total CPIM
CPIM Costs:					
Purchases and Sales:					
EPNG, Kern River, and Transwestern (Baja Path):					
Basin	$ 239,490,239	$ 2,348,868			$ 241,839,107
Transmission Line	$ 31,170,186	$ 7,837,541			$ 39,007,727
GTNC and NGTL (Redwood Path):					$ -
Transmission Line	$ 319,609,343	$ 15,135,987			$ 334,745,330
Citygate (Mission Path)	$ (126,007,354)	$ -			$ (126,007,354)
SubTotal	$ 649,356,335	$ 27,634,300	$ -	$ -	$ 676,990,635
Misc. Revenues and Expenses	$ (10,257,475)				$ (10,257,475)
Fixed and Floating Swaps	$ 593,416				$ 593,416
Option Premiums	$ -				$ -
Total	$ 639,692,276	$ 27,634,300	$ -	$ -	$ 667,326,576
SAP Journal Entries:					
Account 5500010	$ 237,401,135		$ 2,110,080	$ (4,426)	$ 239,506,789
Account 5500021	$ 527,995,268		$ (1,553,817)	$ 45,962	$ 526,487,413
Account 5500041	$ (125,735,320)		$ (473,489)	$ 781,799	$ (125,427,010)
Account 5500054	$ -	$ 8,605,312			$ 8,605,312
Account 5500055	$ -	$ 19,062,864	$ 16,741	$ (6,692)	$ 19,072,913
Pricing Index Gas Refund	$ (770,114)				$ (770,114)
Prior Period Adjustment	$ (115,781)				$ (115,781)
Demand Fees (1)	$ (150,000)				$ (150,000)
FFSW recorded in CPIM	$ 115,333				$ 115,333
CTA Costs not included in CPIM (1)	$ (18,119)				$ (18,119)
CTA Mid Year Storage Adjustment	$ 18,036				$ 18,036
Total PGA	$ 638,740,438	$ 27,668,175	$ 99,515	$ 816,643	$ 667,324,771
Difference	$ 951,838	$ (33,875)	$ (99,515)	$ (816,643)	$ 1,805

3.7 Review of Core Pipeline Demand Charge Account (CPDCA)

PG&E submitted its reconciliation for regulatory balancing account Core Pipeline Demand Charge Account (CPDCA). This account is used to record costs associated with backbone transmission, interstate capacity, and Canadian capacity for core procurement. ORA reviewed PG&E documentation, which shows total charges by pipeline for the period to be $281,660,903.

Balance account entries reflect timing differences for pipeline demand charges, firm storage costs, and pipeline transport charges. Table 3-6 shows total entries were $281,659,950, showing net timing differences of $953.

TABLE 3-7 Pacific Gas and Electric Company Review of CPDCA Balancing Account CPIM Year 19 November 1, 2011 through October 31, 2012				
Reservation Charges by Pipeline	**Reservation Charges**	**Subtract True-up**	**Add True-up**	**Total CPIM**
CPIM Demand Costs:				
Foothills Pipe Lines Ltd.	12,969,045	-	-	12,969,045
California Gas Transmission	55,906,040			55,906,040
Firm Storage Costs	49,095,955			49,095,955
Ruby Pipeline	60,844,326			60,844,326
Lodi Gas Storage	2,344,000			2,344,000
NOVA Gas Transmission	23,110,844			23,110,844
Gas Transmission N.W.	44,447,602			44,447,602
Transwestern Pipeline Company	12,458,075			12,458,075
Kern River Gas	851,543			851,543
Total	$ 281,660,903	$ -	$ -	$ 281,660,903
SAP Journal Entries:				
Account 5500064 - Demand	176,820,685	98,166	6,028	176,924,879
Account 5500065 - Demand	53,959,596			53,959,596
Account 5500067 - Firm Storage	49,025,148			49,025,148
Account 5500055 - Lodi Gas Storage	$2,344,000			2,344,000
EPNG, TW & Kern Reservation Discount	(665,268)			(665,268)
EPNG Cash Out (recorded in 5500055)	0			0
Recorded in the Core Fixed Storage Accour	71,596			71,596
Total CPDCA	$ 281,555,756	$ 98,166	$ 6,028	$ 281,659,950
Timing difference	$ 105,147	$ (98,166)	$ (6,028)	$ 953

3.8 Review of Miscellaneous Costs and Revenues

Table 3-8 shows a summary of miscellaneous costs and credits that agree with reporting from PG&E's Annual Performance Report for the period. Results show total annual miscellaneous costs and revenues at $9,839,300. This amount consists of Broker Fees of $173,215, Cochrane Extraction Revenue of $10,272,857, Peaking Contract Demand Fees of $240,000, Parking and Lending Charges of $18,882, and Usage Storage Charge of $1,460. These revenues offset reported procurement costs and assist management in managing net costs that impact CPIM performance.

TABLE 3-8
Pacific Gas and Electric Company
Miscellaneous Costs and Revenues
CPIM Year 19
November 1, 2011 through October 31, 2012

Month Year	Broker Fees	Cochrane Extraction Revenue	Peaking Contract Demand Fees	Parking and Lending Charges	Usage Storage Charge	Total Misc Charges
Nov-10	$ 17,739	$ (510,386)	$ 240,000	$ 5,490	$ 1,460	$ (245,697)
Dec-10	$ 17,647	$ (909,758)	$ -	$ -	$ -	$ (892,111)
Jan-11	$ 17,269	$ (1,028,858)	$ -	$ -	$ -	$ (1,011,589)
Feb-11	$ 10,001	$ (926,892)	$ -	$ -	$ -	$ (916,891)
Mar-11	$ 20,569	$ (1,026,669)	$ -	$ 6,000	$ -	$ (1,000,100)
Apr-11	$ 15,763	$ (983,093)	$ -	$ 57	$ -	$ (967,273)
May-11	$ 11,703	$ (914,355)	$ -	$ 7,335	$ -	$ (895,317)
Jun-11	$ 13,975	$ (745,791)	$ -	$ -	$ -	$ (731,816)
Jul-11	$ 10,404	$ (791,505)	$ -	$ -	$ -	$ (781,101)
Aug-11	$ 10,880	$ (825,170)	$ -	$ -	$ -	$ (814,290)
Sep-11	$ 12,629	$ (812,080)	$ -	$ -	$ -	$ (799,451)
Oct-11	$ 14,636	$ (798,300)	$ -	$ -	$ -	$ (783,664)
Totals:	$ 173,215	$ (10,272,857)	$ 240,000	$ 18,882	$ 1,460	$ (9,839,300)

3.9 Examination of Financial Derivatives

Pursuant to D.07-06-013, the Commission authorized PG&E's Annual Core Hedge Implementation Plan for 2008 for long term hedging for purchases of call options and swaps for a three-year period. This decision provided highlights for the long-term core hedge program for its requirements of reporting.

D.07-06-013 requires PG&E to report financial options and swaps under its hedging plan. The total hedge premiums and swap losses recorded and recovered from PG&E ratepayers for Year 19 were $69,142,711. The option premiums and financial swaps that were exempt from CPIM is $48,578,694. As shown in Table 3-9, PG&E reported hedge activities with no option premiums, and swap costs of $48,546,200 which are not included in CPIM Year 19 costs.

Table 3-9
Pacific Gas and Electric
CPIM Year 19
November 1, 2011 - October 31, 2012
Financial Derivatives Costs

	Inside CPIM	Outside CPIM	Total
Option Premiums*	$ 8,760,879	$ -	$ 8,760,879
Financial Swaps*	$ 11,526,346	$ 48,546,200	$ 60,072,546
Other Swaps	$ 257,391	$ -	$ 257,391
Fees*	$ 19,401	$ 32,494	$ 51,895
Total Financial Derivatives	$ 20,564,017	$ 48,578,694	$ 69,142,711

*See Table 3-10

The Commission in D.10-01-023 on January 25, 2010, approved a policy incorporating winter hedging transactions into CPIM. The winter hedging transactions executed on or after November 1, 2009 would be included into PG&E's CPIM calculation beginning on or after November 1, 2010. CPIM Year 18 was the first year to include the winter hedge costs and this change adopted for future CPIM calculations. The financial results for all hedges executed for Winter 2011-2012 within CPIM are summarized in the Table 3-10. The total cost of the 2011/2012 Winter Hedge is $20,306,626.

Table 3-10
Pacific Gas and Electric
CPIM Year 19
November 1, 2011 - October 31, 2012
Actual Winter Hedge Costs

	Option Premiums	Swap Settlements	Commissions and Fees	Total
Nov-11	$ -	$ -	$ -	$ -
Dec-11	$ 2,984,475	$ 3,290,917	$ 6,609	$ 6,282,001
Jan-12	$ 2,984,475	$ 3,779,257	$ 6,609	$ 6,770,341
Feb-12	$ 2,791,929	$ 4,456,172	$ 6,183	$ 7,254,284
Mar-12	$ -	$ -	$ -	$ -
Apr-12	$ -	$ -	$ -	$ -
May-12	$ -	$ -	$ -	$ -
Jun-12	$ -	$ -	$ -	$ -
Jul-12	$ -	$ -	$ -	$ -
Aug-12	$ -	$ -	$ -	$ -
Sep-12	$ -	$ -	$ -	$ -
Oct-12	$ -	$ -	$ -	$ -
Total	$ 8,760,879	$ 11,526,346	$ 19,401	$ 20,306,626

3.10 Review of Sales and Volume Transactions

Table 3-11 shows PG&E total sales of $153,057,884, and reported volume of 50,534,827 MMBtus. A breakdown by pipeline shows sales for CGT CityGate of $137,888,435, EPNG-Basin of $216,351, EPNG-Topock of $1,077,943, Kern River-Daggett of $40,740, NGTL-AECO/NIT of $743,376, GTNC-All of 8,919,553, Ruby Pipeline of $2,985,582, TW-Basin of $115,704, and TW-Topock of $1,070,200. The same period sales volume for CGT CityGate showed 44,958,892 MMBtus, EPNG-Basin of 75,948 MMBtus, EPNG-Topock of 349,886 MMBtus, Kern River-Daggett of 12,125 MMBtus, NGTL-AECO/NIT of 369,459 MMBtus, GTNC-All of 3,112,690 MMBtus, Ruby Pipeline of $1,247,080 MMbtu, TW-Basin of 32,747 MMBtus, and TW-Topock of 376,000 MMBtu.

Table 3-11 Pacific Gas and Electric Company Actual Sales and Volume CPIM Year 19 November 1, 2011 through October 31, 2012		
Sales by Pipeline:	**Volume (MMBtus)**	**$ Dollars**
CGT CityGate	44,958,892	$ 137,888,435
EPNG-Basin	75,948	216,351
EPNG-Topock	349,886	1,077,943
Kern River-Daggett	12,125	40,740
NGTL-AECO/NIT	369,459	743,376
GTNC-All	3,112,690	8,919,553
Ruby Pipeline	1,247,080	2,985,582
TW Basin	32,747	115,704
TW Topock	376,000	1,070,200
Total:	50,534,827	$ 153,057,884

3.11 Review of Volumetric Transport Costs

Table 3-12 provides a summary of PG&E's reported volumetric transportation costs by pipeline. Trends in transport activity are consistent with purchase and sales transactions.

The total volumetric transport costs were $27,657,466. In addition, costs were broken down by pipeline to identify changes: CGT-Baja reported $7,837,541 in costs, CGT-Redwood $13,561,388, EPNG-Basin $1,971,654, Kern River-Daggett $9,925, NGTL-AECO/NIT $38,852, GTNC-All $1,535,747, Ruby Pipeline $2,311,904, and Transwestern-Basin $390,455. These costs are included in the CPIM and are part of the reconciliation of the PGA balancing account.

TABLE 3-12 Pacific Gas and Electric Company Commodity Volumetric Transport Costs CPIM Year 19 November 1, 2011 through October 31, 2012	
CGT-Baja	$ 7,837,541
CGT-Redwood	13,561,388
EPNG-Basin	1,971,654
Kern River-Daggett	9,925
NGTL-AECO/NT	38,852
GTNC-ALL	1,535,747
Ruby Pipeline	2,311,904
TW-Basin	390,455
Total Volumetric Transport Costs:	$ 27,657,466

3.12 Review of Reservation Charges

ORA completed a reconciliation of the benchmark to actual reservation charges reported in PG&E's Annual Performance Report for subject period to identify any variances. Table 3-13 provides a summary of adjustments that were offset against the benchmark. The results show no discrepancies. The reconciliation accounts for actual reservation charges was $241,012,697, and adjustments to this amount were for discounted demand charges of $665,268, capacity release revenue of $12,075,415, discount capacity release of $1,948,934, and storage cost of $51,439,955.

TABLE 3-13
Pacific Gas and Electric Company
Reconciliation of Reservation Charges
CPIM Year 19
November 1, 2011 through October 31, 2012

				Benchmark Demand Charges:
Actual Demand Charges by Pipeline System:				
Canadian			**$**	**241,012,697**
Foothills Pipelines Ltd.		12,969,045		
Nova Gas Transmission Ltd.		23,110,844		
Canadian Subtotal	$	36,079,889		
Interstate				
Gas Transmission Northwest Corporation		44,447,602		
El Paso Natural Gas Company		21,045,908		
Kern River Gas Transmission		1,692,656		
Ruby Pipeline		61,134,526		
Transwestern Pipeline Company		18,548,934		
Interstate Subtotal	$	146,869,626		
Intrastate				
California Gas Transmission Baja		27,591,514		
California Gas Transmission Redwood		30,471,668		
California Gas Transmission Silverdo		-		
Intrastate Subtotal	$	58,063,182		
Total Actual Demand Charges:	$	241,012,697	$	241,012,697
Discount Demand Charges:				
El Paso Natural Gas Company		(465,233)		
Transwesten Pipeline Company		(140,924)		
Kern River Gas Transmission		(59,111)		
Demand Charge Discount Subtotal:	$	(665,268)	$	-
Capacity Release Revenue:				
Canadian Pipeline		0		
Interstate Pipeline		(7,969,339)		
Intrastate		(4,106,076)		
Total Capacity Release Revenue:	$	(12,075,415)	$	-
Discounted (Premium) Capacity Release:				
Canadian Pipelines		0		
Intrastate Pipelines		1,948,934		
Total Discounted (Premium) Capacity Release:	$	1,948,934	$	-
Storage Cost:				
California Gas Transmission Firm Storage		49,095,955		
Lodi Gas Storage, Inc.		2,344,000		
Storage Cost Subtotal:	$	51,439,955	$	51,439,955
Reconciliation of Reservation Charges:	**$**	**281,660,903**	**$**	**292,452,652**

3.13 Review of Benchmark Commodity Indices

Table 3-12 provides a summary of PG&E's CityGate indices used to calculate the benchmark of monthly commodity costs. These indices are reported to *Natural Gas Intelligence*, which publishes them in their gas price index. As such, these indices were applied to the CityGate benchmark volume reported.

The Canadian benchmark commodity indices are established using the exchange rates in effect when the indices are issued prior to the availability of closing currency exchange rates. However, the final indices, which determine the actual gas supply prices, reflect closing exchange rates.

For the reporting period, PG&E's gas operations apply a pipeline sequencing methodology for purposes of purchasing gas at the lowest cost. PG&E however has the discretion to change the sequence to select a pipeline at any time in order to meet reliability requirements.

TABLE 3-12
Pacific Gas and Electric Company
PG&E City Gate Indices
CPIM Year 19
November 1, 2011 through October 31, 2012

	Ruby Rookies	AECO	San Juan	Kingsgate	Kern River	Topock	PG&E Citygate Daily
Nov-11	3.59153	3.44781	3.58872	3.77122	3.63366	3.67176	3.89
Dec-11	3.53080	3.49721	3.48517	3.82363	3.56741	3.68186	3.38
Jan-12	3.22806	3.20324	3.28068	3.53114	3.25246	3.43194	3.06
Feb-12	2.68151	2.62495	2.69046	2.95464	2.69630	3.03800	2.76
Mar-12	2.54697	2.26010	2.56620	2.59223	2.55253	2.66426	2.39
Apr-12	2.03815	1.97570	2.05279	2.30842	2.03454	2.29052	2.30
May-12	1.95674	1.73282	1.98053	2.05177	1.95106	2.20971	2.70
Jun-12	2.46047	2.16029	2.52765	2.48144	2.58756	2.64406	2.99
Jul-12	2.55920	2.14776	2.66185	2.47535	2.58986	2.90668	3.20
Aug-12	2.92284	2.61904	3.01283	2.95367	2.96025	3.09860	3.00
Sep-12	2.56930	2.39589	2.65152	2.73378	2.60166	2.83598	3.61
Oct-12	2.88243	2.64722	2.94057	2.97752	2.91858	3.22992	3.94

3.14 Examination of Fixed Storage and Transportation Costs

PG&E reported its benchmark reservation (demand) and fixed storage charges. Based on this report, ORA reviewed the costs and identified changes in activity from the prior year report. The total transportation and storage costs are $292,452,652, which consisted of the Canadian pipeline demand charges of $36,079,889, U.S. interstate pipeline reservation costs of $146,869,626, California intrastate pipeline costs of $58,063,182, and storage costs of $51,439,955. Table 3-16 provides a summary of these costs.

TABLE 3-16
Pacifc Gas and Electric Company
Summary of Fixed Transport and Storage Costs
CPIM Year 19
November 1, 2011 through October 31, 2012

Benchmark Demand Charges			
Canadian			
Foothills Pipelines Ltd.			12,969,045
Nova Gas Transmission Ltd.			23,110,844
	Canadian Subtotal	$	36,079,889
Interstate			
Gas Transmission Northwest Corporation			44,447,602
El Paso Natural Gas Company			21,045,908
Kern River Gas Transmission			1,692,656
Ruby Pipeline			61,134,526
Transwestern Pipeline Company			18,548,934
	Interstate Subtotal		146,869,626
Intrastate			
California Gas Transmission Baja			27,591,514
California Gas Transmission Redwood			30,471,668
California Gas Transmission Silverdo			-
	Intrastate Subtotal	$	58,063,182
	Total Demand Charges	$	241,012,697
CA Intrastate Storage Costs:			
California Gas Transmission Firm Storage			
Firm Storage Cost			49,095,955
Lodi Gas Storage, Inc.			
Demand Charge			2,322,000
Injection/Withdrawal Charge			22,000
Total CA Storage Costs:		$	51,439,955
Total Transportation & Storage Costs:		$	292,452,652

3.15 Utilization of Firm Interstate and Intrastate Pipeline Assets

PG&E has short and long term contracts for purchases of natural gas resources transported from Canadian, U.S. interstate and California intrastate pipeline systems to meet core gas demand. During Year 19, PG&E transported these resources using firm transportation contracts. The summary in Table 3-17 below shows PG&E's estimated utilization for the period and noted changes in contract activity from prior year.

PG&E estimates utilization proportionally based on capacity available to transport supplies and/or releases to other parties.

Pursuant to D.04-09-022, [16] PG&E is authorized to recover the costs associated with its Canadian and U.S. interstate capacity, allocate firm intrastate capacity and recover associated costs.

Pursuant to D.07-07-002, PG&E can also allocate firm intrastate capacity and recover associated costs. In the CPIM Year 19, PG&E added the Ruby pipeline to PG&E's core supply portfolio effective November 1, 2011. The Ruby pipeline provides contracted quantities of 250,000 Dth/d.[17]

---

[16] D.04-09-022, OIR to establish Policies and Rules to Ensure Reliable; Long term Supplies of Natural Gas to California.

[17] PG&E's Core Procurement Incentive Mechanism Year 19.

Pacific Gas and Electric Company
Core Gas Supply - Utilization of Interstate, Intrastate and Canadian Pipeline Assets
CPIM Year 19
November 1, 2011 through October 31, 2012

Pipeline Capacity:	Quantity (Dth/d)	Contract Expiration Date	Utilization Rate
TransCanada Pipelines:			
NOVA	287,745	10/31/16	
	82,223	10/31/20	
Total NOVA:	369,968		100%
	284,810	10/31/13	
Foothills-BC System	81,384	10/31/13	
Total Foothills-BC System:	366,194		100%
Interstate Pipelines:			
Gas Transmission Northwest	279,968	10/31/16	
	80,000	10/31/20	
Total Gas Transmission Northwest:	359,968		100%
El Paso Natural Gas	116,035	06/30/12	
	66,000	06/30/13	
	85,739	06/30/13	
Total El Paso Natural Gas:	Varies		97%
Transwestern Pipeline Co.	150,000	03/31/13	
Seasonal 11-12 (Dec-Feb.)	43,220	02/28/12	
Total Transwestern Pipeline Co:	193,220		99%
Ruby	250,000	10/31/26	84%
Kern River	50,033	06/30/13	96%
Intrastate Pipelines:			
Redwood Path	608,766	No expiration	99%
Baja Path	348,000	No expiration	
Seasonal (Dec-Feb)	321,000	No expiration	
Total Baja Path Capacity:	669,000		75%

Appedix A
Exhibits For CPIM Year 18

Section	Descriptioin	Exhibit Number
Reward Calcuation 2-1		
	CPIM Calculation	2-A
	CPIM Performance	2-A1
	Monthly Benchmark Cost Total	2-B1
	Monthly Actual Cost Total	2-B
Benchmark 2-2		
	Benchmark Commodity Costs	2-C1
	Bechmark Sequenced Volume	2-E
Actual Cost 2-2		
	Actual Commodity Cost	2-C
	Gas Purchase Volume	2-F
Sales 2-3		
	Gas Sale	2-C3
	Gas Sale Volume	2-G
Transportation Cost 2-4		
	Volumetric Transportation Cost	2-C2
Reservation Costs 2-5		
	Reservation Charge	2-D
	Reservation Charge Discount	2-D1
Storage/Inventory 2-6		
	Firm Storage Inventory	2-H
	Storage Cost	2-D4
	Incremental Storage Cost	2-D5
	Injection/Withdraw Charge	2-D6
Miscellaneous Costs 2-7		
	Miscellaneous Costs and Revenues	2-C4
	Capacity Release Revenue	2-D2
	Capacity Release Discount (Premium)	2-D3
	Refund Credit	2-D7
	Other Charges and Credits	2-D8
Hedge Cost 2-8		
	Actual Winter Hedge Cost	2-C5
	Benchmark Winter Hedge Cost	2-C6

Appedix A
Exhibits For CPIM Year 19

Section	Descriptioin	Exhibit Number
Reward Calcuation 3-1		
	CPIM Calculation	3-A
	CPIM Performance	3-A1
	Monthly Benchmark Cost Total	3-B1
	Monthly Actual Cost Total	3-B
Benchmark 3-2		
	Benchmark Commodity Costs	3-C1
	Bechmark Sequenced Volume	3-E
Actual Cost 3-2		
	Actual Commodity Cost	3-C
	Gas Purchase Volume	3-F
Sales 3-3		
	Gas Sale	3-C3
	Gas Sale Volume	3-G
Transportation Cost 3-4		
	Volumetric Transportation Cost	3-C2
Reservation Costs 3-5		
	Reservation Charge	3-D
	Reservation Charge Discount	3-D1
	Capacity Release Revenue	3-D2
	Capacity Release Discount (Premium)	3-D3
Storage/Inventory 3-6		
	Firm Storage Inventory	3-H
	Storage Cost	3-D4
	Incremental Storage Cost	3-D5
Miscellaneous Costs 3-7		
	Miscellaneous Costs and Revenues	3-C4
	Refund Credit	3-D7
	Other Charges and Credits	3-D8
Hedge Cost 3-8		
	Actual Winter Hedge Cost	3-C5
	Benchmark Winter Hedge Cost	3-C6