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OFFICE OF RATEPAYER ADVOCATES
California Public Utilities Commission

MONITORING AND EVALUATION REPORT

November 1, 2012 through October 31, 2013

Pacific Gas and Electric Company's
Core Procurement Incentive Mechanism
Performance Results
(CPIM Year 20)

Application 96-08-043

San Francisco, California
February 06, 2015

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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, 2012 through October 31, 2013 (Year 20). The details and results of ORA's review are presented in Chapter 2 of this ORA CPIM Monitoring and Evaluation 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 20 which resulted in ratepayer savings.

For Year 20, PG&E submitted its CPIM Performance Report on June 13, 2014 for the period November 1, 2012 through October 31, 2013. ORA's examination of PG&E's recorded costs for Year 20 shows that PG&E's costs were below the benchmark lower tolerance band, which results in a reward of $1,397,952[1] to PG&E's shareholders and a ratepayer benefit of $13,881,888.[2]

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

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[1] ORA Monitoring and Evaluation Report CPIM Year 20, Table 1-1.

[2] Id.

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 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 20 totaled $1,074,518,806 which was associated with a volume of 241,969,450,450 MMBtus (net of sales).

PG&E utilized gas sales to help manage its assets and reduce gas costs. It purchases and sells gas supplies to comply with daily pipeline balancing requirements, to respond to changes in core loads, and to capture price arbitrage opportunities. For CPIM Year 20, PG&E reported total gas sales of $238,265,336 in revenue with associated sale volume of 60,800,743 MMBtus.

1.4 Financial Hedging Activities

Per D.07-06-013, 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. 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.[3]

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 current Year 20, the total costs of financial derivatives included in CPIM were $22,786,580.[4] The Winter Hedge costs were $23,132,296, which comprised of

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[3] 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, December 15, 2006.

[4] ORA Monitoring and Evaluation Report CPIM Year 20, Table 2-9

$10,066,146 in option premiums, $13,039,220 in financial swaps, and $26,930 in fees. The swaps outside of winter hedge resulted in revenue of $345,716.[5]

1.5 Natural Gas Storage

Under the CPIM, PG&E has a daily injection and withdrawal schedule. During CPIM Year 20, storage inventory injections were 27,789,214 MMBtus, and storage withdrawals were 30,247,172 MMBtus. Beginning inventory was reported at 33,827,267 MMBtus, and ending inventory shows 31,369,309 MMBtus.

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 storage profile beginning in Year 17 and will be adjusted for allocations to

[5] ORA Monitoring and Evaluation Report CPIM Year 20, Table 2-9.

Core Transport Agents (CTAs) as detailed in Tariff G-CT. This MOU will remain in effect until both parties agree to make changes.[6]

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.

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. Currently, PG&E holds Redwood and Baja intrastate capacity which providing approximately 956 MDth/d and an additional of 321 Mdth/d during December to February.[7]

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), Ruby Pipeline, LLC (Ruby), and Kern River Gas Transmission Company (Kern River).

For Year 20, core interstate capacity was reported at approximately 370 MDth/d for NOVA, 366 MDth/d on the BC System, 360 MDth/d on GTN, 192 MDth/d on EPNG, 293 MDth/d on TW, 250 MDth/d on Ruby, and 60 MDth/d on Kern River.[8]

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

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

[7] PG&E Annual Performance Report, Year 20, Table IV.

[8] PG&E Annual Performance Report, Year 20, Table IV.

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.

In Advice Letter 3242-G, PG&E had two contract extensions for Foothills approved. 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 October 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 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.

Authorized by Advice Letter 3368-G PG&E executed one year flat annual contracts on El Paso (30,000 Dth/d) and Kern River (10,000 Dth/d) effective July 1, 2013, and one seasonal contract on Kern River (55,000 Dth/d) effective from December 1, 2013 to March 31, 2014.

1.8 Review of CPIM Performance

Table 1-1 below compares benchmark gas costs to actual costs of natural gas (including transportation, reservation and storage costs) in total dollars.

Table 1-1 CPIM Year 20 Gas Cost Comparison November 1, 2012-October 31, 2013		
CPIM Year 20		
Actual Gas Cost	$ 1,074,518,806	
Benchmark Gas Cost	$ 1,089,798,654	
Total Saving		$ 15,279,848
PG&E Reported Year 20 Saving	$ 15,279,840	
Rounding Difference	$ 8	
Variance		$ -
Saving and Reward		
Ratepayer Saving		$ 13,881,888
Shareholder Reward		$ 1,397,952

1.9 Conclusion

Based on the foregoing, ORA recommends a shareholder reward to PG&E for Year 20 of $1,397,952 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 20

2.1 ORA's CPIM Reward Evaluation

Pacific Gas and Electric Company (PG&E) filed its Core Procurement Incentive Mechanism (CPIM) Performance Report, Year 20 Application (A.96-08-043), which reports on natural gas procurement results for the period from November 1, 2012 through October 31, 2013. 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.[9] 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.

The 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) variable costs which include commodity costs, Canadian, U.S. interstate, and California intrastate pipeline fuel and volumetric capacity costs; b) fixed transportation costs which include Canadian, U.S. interstate, and California intrastate reservation 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

[9] 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.

associated 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 on annual basis against the benchmark and the calculated tolerance band. The benchmark commodity cost 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 20 performance in Table 2-1 shows benchmark commodity costs of $1,089,798,654 and PG&E's actual commodity cost is $1,074,518,806. The difference between the benchmark commodity cost and PG&E's actual commodity cost results in $15,279,848 of total natural gas procurement savings. Results show the upper tolerance band benchmark (benchmark plus 2.0% of commodity benchmark plus reservation charges) is $1,106,378,806, and the lower tolerance band benchmark (benchmark minus 1.0% of commodity benchmark plus reservation charges) is $1,081,508,577.

The actual commodity cost of $816,785,698 is $12,222,014 less than the benchmark commodity cost of $829,007,712. 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 20 savings below the lower tolerance band, and results in total savings of $15,279,848. Based on the CPIM, this saving is shared between ratepayers of $5,591,817 and a shareholder reward of $1,397,954. The total ratepayer savings is $13,881,894.

TABLE 2-1 Pacific Gas & Electric Company Ratepayer Savings and Shareholder Award Calculation CPIM 20 November 1, 2012 Through October 31, 2013		
CPIM Reward Calculation		
Total Benchmark Costs	$	1,089,798,654
Total Actual Costs		1,074,518,806
Under/(Over)		15,279,848
Upper Tolerance Band (Benchmark + 2% of Commodity Cost)		1,106,378,806
Lower Tolerance Band (Benchmark - 1% of Commodity Cost)		1,081,508,577
Lower Tolerance Band Less Actual Commodity Cost		6,989,771
Ratepayer Shared Savings (80%)		5,591,817
Shareholder Shared Savings (20%)		1,397,954
	$	6,989,771
Total Ratepayer Savings	$	13,881,894

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 20.

ORA examined and reconciled all gas commodity costs, hedge costs, and transportation reservation charges that were reported in the CPIM Year 20 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 2-2
Pacific Gas & Electric Company
Summary of Benchmark and Actual Costs
CPIM 20
November 1, 2012 Through October 31, 2013

		Actual		Benchmark		Difference
Purchased Natural Gas Cost	$	1,039,642,350	$	810,501,874	$	(229,140,476)
Natural Gas Sales	$	(238,265,336)	$	-	$	238,265,336
Miscellaneous Costs and Revenues	$	(7,377,896)	$	-	$	7,377,896
Hedge Cost	$	22,786,580	$	18,505,838	$	(4,280,742)
Reservation Charges	$	257,733,108	$	260,790,942	$	3,057,834
Total Commodity Cost	$	1,074,518,806	$	1,089,798,654	$	15,279,848

2.3 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 2-3 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 $1,089,798,654. The benchmark commodity costs are $810,501,874 the benchmark winter hedge costs are $18,505,838 and benchmark pipeline reservation charges are $260,790,942.

TABLE 2-3
Benchmark Commodity Costs and Reservation Charges
CPIM Year 20
November 1, 2012 Through October 31, 2013

		Market Benchmark
Benchmark Purchased Gas Costs - by Pipelines:		
Ruby Rockies	$	187,392,572
AECO	$	361,745,626
San Juan	$	170,918,966
Kingsgate	$	465,883
Kern River	$	46,353,601
Topock	$	37,002,038
PG&E Citygate	$	6,623,188
Total Benchmark Gas Costs:	$	810,501,874
Hedging Cost		
80% of Winter Hedging Cost	$	18,505,838
Benchmark Reservation Charges:		
Foothills Pipelines Ltd	$	10,176,625
Nova Gas Transmission Ltd	$	20,971,125
Gas Transmission Northwest Corp	$	42,163,536
El Paso Natural Gas Company	$	11,576,917
Kern River Gas Transmission	$	57,866,324
Ruby Pipeline	$	3,496,825
Transwestern Pipeline Company	$	12,042,502
California Gas Transmission	$	54,156,513
CGT Storage	$	45,988,831
Losdi Gas Storage, Inc.	$	2,322,000
Injection/Withdraw Charges	$	29,744
Total Benchmark Reservation Charges:	$	260,790,942
Total Benchmark Commodity Costs:	$	1,089,798,654

2.4 Actual Natural Gas Costs

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 20, 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 TransCanada 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.[10]

PG&E's net total actual commodity costs are $1,074,518,806, which include interstate and intrastate purchased gas costs of $793,999,118, winter hedging cost of $22,786,580, reservation charges for interstate and California intrastate capacity of $257,733,108.

[10] PG&E Annual Performance Report, CPIM Year 20, dated June 13, 2014.

TABLE 2-4
Summary of Actual Commodity Costs & Reservation Charges
CPIM Year 20
November 1, 2012 Through October 31, 2013

Actual Purchased Gas Costs - by Pipeline:		**Actual Costs**
CGT-Citygate	$	16,903,621
EPNG-Basin	$	129,849,197
EPNG-Topock	$	14,681,842
Kern River-Daggett	$	16,873,188
Kern River-Opal	$	47,636,060
NGTL-AECO/NIT	$	388,538,790
GTNC-All	$	2,388,955
Ruby Pipeline	$	247,445,404
TW-Basin	$	135,029,042
TW-Topock	$	13,800,309
Volumetric Transportation Cost	$	26,495,942
Gas Sale	$	(238,265,336)
Miscellaneous Costs & Revenues	$	(7,377,896)
Total Purchased Gas Costs:	$	793,999,118
Hedging Costs		
100% Winter Hedging Cost	$	22,786,580
Actual Reservation Charges:		
Foothills Pipelines Ltd	$	10,176,625
Nova Gas Transmission Ltd	$	20,971,125
Gas Transmission Northwest Corp	$	42,163,536
El Paso Natural Gas Company	$	11,576,917
Kern River Gas Transmission	$	57,866,324
Ruby Pipeline	$	3,496,825
Transwestern Pipeline Company	$	12,042,502
California Gas Transmission	$	54,156,513
CGT Storage	$	45,988,831
Losdi Gas Storage, Inc.	$	2,322,000
Discount Demand Charges	$	(551,496)
Capacity Release Revenue	$	(3,319,717)
Discounted/(Premium) Capacity Release	$	813,379
Injection/Withdraw Charges	$	29,744
Total Reservation Charges:	$	257,733,108
Net Actual Commodity Costs:	$	1,074,518,806

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.[11]

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.[12]

ORA's Exhibit 2-D4 show total storage charges were $48,310,831, which include $45,988,831 paid to California Gas Transmission (CGT), and $2,322,000 to Lodi Gas Storage, Inc. In addition to storage costs, there was an injection and withdrawal cost of $29,744 for Lodi Gas storage 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, 2013. PG&E reported beginning storage inventory levels as of November 1, 2012 at 33,827,267 MMBtus and ending inventory as of October 31, 2013 at 31,369,309 MMBtus. In this CPIM period, injection and withdrawal levels show 27,789,214 MMBtus of injections, and 30,247,172 MMBtus of withdrawals.

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[11] PG&E Annual Performance Report, CPIM Year 20, dated June 13, 2014.

[12] 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 20 November 1, 2012 through October 31, 2013				
Natural Gas Storage Providers	**Beginning Inventory 11/01/12 (MMBtus)**	**Injections**	**Withdrawals**	**Ending Inventory 10/31/13 (MMBtus)**
Pacific Gas & Electric CGT	32,327,267	26,314,778	(28,747,172)	29,894,873
Lodi Storage, Inc.	1,500,000	1,474,436	(1,500,000)	1,474,436
Total Storage Inventory	33,827,267	27,789,214	(30,247,172)	31,369,309

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 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 2-6 below shows net commodity costs of $793,999,118, 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 2-6 Pacific Gas and Electric Company Purchase Gas Account Review CPIM Year 20 November 1, 2012 through October 31, 2013					
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	$ 263,816,727	$ 1,769,851			$ 265,586,578
Transmission Line	$ 89,174,137	$ 7,803,879			$ 96,978,016
GTN and NGTL (Redwood Path):					
Transmission Line	$ 376,155,209	$ 14,129,673			$ 390,284,882
Ruby Pipeline	$ 246,833,898	$ 2,792,539			$ 249,626,437
Citygate (Mission Path)	$ (201,098,899)	$ -			$ (201,098,899)
SubTotal	$ 774,881,072	$ 26,495,942	$ -	$ -	$ 801,377,014
Misc. Revenues and Expenses	$ (7,377,896)				$ (7,377,896)
Total	$ 767,503,176	$ 26,495,942	$ -	$ -	$ 793,999,118
SAP Journal Entries:					
Account 5500010	$ 263,694,998		$ 4,426	$ 46,843,482	$ 310,542,906
Account 5500021	$ 704,488,480		$ (45,962)	$ (46,626,804)	$ 657,815,714
Account 5500041	$ (200,219,635)		$ (781,799)	$ 91,066	$ (200,910,368)
Account 5500054	$ -	$ 6,352,075			$ 6,352,075
Account 5500055	$ -	$ 20,155,273	$ 6,692	$ (7,508)	$ 20,154,457
Account 5500067	$ 10,725				$ 10,725
Interest	$ 343				$ 343
Prior Period Adjustment	$ 2,351				$ 2,351
Demand Fees	$ 150,000				$ 150,000
Demand Fees	$ (125,000)				$ (125,000)
OFO Charge	$ 5,909				$ 5,909
Total PGA	$ 768,008,171	$ 26,507,348	$ (816,643)	$ 300,236	$ 793,999,112
Difference	$ (504,995)	$ (11,406)	$ 816,643	$ (300,236)	$ 6

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 $209,392,520.

The audit shows the CPIM demand costs was $209,392,522 which included the demand charges, discount demand charges, capacity release revenue and release revenue charges. Balance account entries reflect timing differences for pipeline demand charges of $34,644. Comparing the reported CPIM demand costs and SAP journal entries, the total difference was $13. This is a rounding difference in the journal entries.

TABLE 2-7
Pacific Gas and Electric Company
CPDCA Account Review
CPIM Year 20
November 1, 2012 through October 31, 2013

CPIM Demand Costs	Demand Charges	Subtract True-up	Add True-up	Total CPIM
Foothills Pipe Lines Ltd	$ 10,176,625			$ 10,176,625
California Gas Transmission	$ 52,005,953			$ 52,005,953
El Paso Natural Gas	$ 11,206,831			$ 11,206,831
Ruby Pipeline	$ 57,769,224			$ 57,769,224
NOVA Gas Transmission	$ 20,941,847			$ 20,941,847
Gas Transmission N.W.	$ 42,163,536			$ 42,163,536
Transwestern Pipeline Company	$ 11,762,642			$ 11,762,642
Kern River Gas	$ 3,365,875			$ 3,365,875
Total Demand Charges:	$ 209,392,533	$ -	$ -	$ 209,392,533
SAP Journal Entries				
Account 5500064	$ 158,807,422	$ (6,028)	$ (29,629)	$ 158,771,765
Account 5500065	$ 51,176,742			$ 51,176,742
EPNG, TW & Kern Reservation Discoun	$ (551,496)			$ (551,496)
Interest	$ (343)			$ (343)
Prior Period Adjustments	$ (4,148)			$ (4,148)
Total CPDCA:	$ 209,428,177	$ (6,028)	$ (29,629)	$ 209,392,520
Timing Difference:	$ (35,644)	$ 6,028	$ 29,629	$ 13

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 $7,377,896. This amount consists of Broker Fees of $147,520, Cochrane Extraction Revenue of $7,702,988, Peaking

Contract Demand Fees of $150,000, OFO Charge of $15,267, Interest Cost of $685, Parking and Lending Charges of $895, and Usage Storage Charge of $10,725. 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 20
November 1, 2012 through October 31, 2013

Month	Broker Fees	Cochrane Extraction Revenue	Peaking Contract Demand Fees	OFO Charge	Interest	Parking and Lending Charges	Usage Storage Charge	Total
Nov-12	$ 14,190	$ (724,442)	$ 150,000	$ -	$ -	$ -	$ -	$ (560,252)
Dec-12	$ 9,899	$ (736,104)	$ -	$ 15,267	$ -	$ -	$ -	$ (710,938)
Jan-13	$ 10,692	$ (725,690)	$ -	$ -	$ -	$ -	$ -	$ (714,998)
Feb-13	$ 11,339	$ (661,108)	$ -	$ -	$ -	$ -	$ -	$ (649,769)
Mar-13	$ 14,695	$ (715,988)	$ -	$ -	$ -	$ -	$ -	$ (701,293)
Apr-13	$ 16,448	$ (663,150)	$ -	$ -	$ -	$ -	$ -	$ (646,702)
May-13	$ 15,673	$ (254,090)	$ -	$ -	$ -	$ -	$ -	$ (238,417)
Jun-13	$ 12,197	$ (353,211)	$ -	$ -	$ -	$ -	$ 10,725	$ (330,289)
Jul-13	$ 11,136	$ (691,150)	$ -	$ -	$ -	$ -	$ -	$ (680,014)
Aug-13	$ 14,101	$ (717,329)	$ -	$ -	$ 343	$ -	$ -	$ (702,885)
Sep-13	$ 8,331	$ (739,260)	$ -	$ 5,909	$ 342	$ 895	$ -	$ (723,783)
Oct-13	$ 8,819	$ (721,466)	$ -	$ (5,909)	$ -	$ -	$ -	$ (718,556)
Total	$ 147,520	$ (7,702,988)	$ 150,000	$ 15,267	$ 685	$ 895	$ 10,725	$ (7,377,896)

2.9 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 20 were $22,786,580. The total of the Winter Hedge is $23,132,296. The financial swaps that were outside of Winter Hedge result of revenue of $345,716 as shown in Table 2-9.

Table 2-9 Pacific Gas and Electric CPIM Year 20 November 1, 2012 - October 31, 2013 Financial Derivatives Costs			
	Inside Winter Hedge	Outside Winter Hedge	Total
Option Premiums*	$ 10,066,146	$ -	$ 10,066,146
Financial Swaps*	$ 13,039,220	$ (345,716)	$ 12,693,504
Other Swaps	$ -	$ -	$ -
Fees*	$ 26,930	$ -	$ 26,930
Total Financial Derivatives	$ 23,132,296	$ (345,716)	$ 22,786,580
*See Table 2-10			

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 current CPIM Year 20, Winter 2012-2013 are summarized in the Table 2-10.

Table 2-10 Pacific Gas and Electric CPIM Year 20 November 1, 2012 - October 31, 2013 Actual Winter Hedge Costs				
	Option Premiums	Swap Settlements	Commissions and Fees	Total
Nov-12	$ -	$ -	$ -	$ -
Dec-12	$ 3,467,228	$ 3,971,164	$ 9,276	$ 7,447,668
Jan-13	$ 3,467,228	$ 4,744,141	$ 9,276	$ 8,220,645
Feb-13	$ 3,131,690	$ 4,323,915	$ 8,378	$ 7,463,983
Mar-13	$ -	$ -	$ -	$ -
Apr-13	$ -	$ -	$ -	$ -
May-13	$ -	$ -	$ -	$ -
Jun-13	$ -	$ -	$ -	$ -
Jul-13	$ -	$ -	$ -	$ -
Aug-13	$ -	$ -	$ -	$ -
Sep-13	$ -	$ -	$ -	$ -
Oct-13	$ -	$ -	$ -	$ -
Total	$ 10,066,146	$ 13,039,220	$ 26,930	$ 23,132,296

2.10 Review of Sales and Volume Transactions

Table 2-11 shows PG&E total sales of $23,265,336, and reported volume of 60,800,743 MMBtus. A breakdown by pipeline shows sales for CGT CityGate of $218,002,520, EPNG-Basin of $1,058,760, EPNG-Topock of $406,927, Kern River Opal of $389, NGTL-AECO/NIT of $2,747,381, GTN-All of 12,025,155, Ruby Pipeline of $4,020,510, TW-Basin of $2,752, and TW-Topock of $942.

The same period sales volume for CGT CityGate showed 54,840,884 MMBtus, EPNG-Basin of 290,368 MMBtus, EPNG-Topock of 105,795 MMBtus, Kern River Opal of 100 MMBtus, NGTL-AECO/NIT of 1,019,657 MMBtus, GTN-All of 3,462,561 MMBtus, Ruby Pipeline of 1,080,376 MMbtu, TW-Basin of 754 MMBtus, and TW-Topock of 248 MMBtu.

Table 2-11
Pacific Gas and Electric Company
Gas Sale and Volume
CPIM Year 20
November 1, 2012 through October 31, 2013

Sale by Pipeline:	Volume (MMBtus)		Dollars
CGT CityGate	(54,840,884)	$	(218,002,520)
EPNG Basin	(290,368)	$	(1,058,760)
EPNG Topock	(105,795)	$	(406,927)
Kern River Opal	(100)	$	(389)
NGTL AECO/NIT	(1,019,657)	$	(2,747,381)
GTN All	(3,462,561)	$	(12,025,155)
Ruby	(1,080,376)	$	(4,020,510)
TW Basin	(754)	$	(2,752)
TW Topock	(248)	$	(942)
Total:	(60,800,743)		(238,265,336)

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 $26,495,942. In addition, costs were broken down by pipeline to identify changes: CGT-Baja reported $7,803,879 in costs, CGT-Redwood $12,727,126, EPNG-Basin $1,198,959, Kern River-Daggett $83,353, GTN-All $1,402,547, Ruby Pipeline $2,792,539, and Transwestern-Basin $487,539. 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 20 November 1, 2012 through October 31, 2013		
Pipeline	**Costs**	
CGT-Baja	$	7,803,879
CGT-Redwood	$	12,727,126
EPNG-Basin	$	1,198,959
Kern River-Daggett	$	83,353
GTN-ALL	$	1,402,547
Ruby Pipeline	$	2,792,539
TW-Basin	$	487,539
Total Volumetric Transport Costs:	$	26,495,942

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. Table 2-13 provides a summary of adjustments that were offset against the benchmark. The results show no discrepancies. The reconciliation accounts for actual reservation charges was $257,733,108, and adjustments to this amount were for discounted demand charges of $511,496, capacity release revenue of $3,319,717, discount capacity release of $813,379, and storage cost of $48,340,575.

TABLE 2-13
Pacific Gas and Electric Company
Reconciliation of Reservation Charges
CPIM Year 20
November 1, 2012 through October 31, 2013

				Benchmark Demand Charges:
Actual Demand Charges by Pipeline System:				
Canadian			**$**	**212,450,367**
Foothills Pipelines Ltd.		10,176,625		
Nova Gas Transmission Ltd.		20,971,125		
Canadian Subtotal	$	31,147,750		
Interstate				
Gas Transmission Northwest Corporation		42,163,536		
El Paso Natural Gas Company		11,576,917		
Kern River Gas Transmission		3,496,825		
Ruby Pipeline		57,866,324		
Transwestern Pipeline Company		12,042,502		
Interstate Subtotal	$	127,146,104		
Intrastate				
California Gas Transmission Baja		26,120,434		
California Gas Transmission Redwood		28,036,079		
Intrastate Subtotal	$	54,156,513		
Total Actual Demand Charges:	$	212,450,367	$	212,450,367
Discount Demand Charges:				
El Paso Natural Gas Company		(284,286)		
Transwesten Pipeline Company		(136,260)		
Kern River Gas Transmission		(130,950)		
Demand Charge Discount Subtotal:	$	(551,496)	$	-
Capacity Release Revenue:				
Canadian Pipeline		(33,200)		
Interstate Pipeline		(326,500)		
Intrastate		(2,960,017)		
Total Capacity Release Revenue:	$	(3,319,717)	$	-
Discounted (Premium) Capacity Release:				
Canadian Pipelines		3,922		
Interstate Pipelines		809,457		
Total Discounted (Premium) Capacity Release:	$	813,379	$	-
Storage Cost:				
California Gas Transmission Firm Storage		45,988,831		
Lodi Gas Storage, Inc.		2,322,000		
Injection/Withdraw Charges		29,744		
Storage Cost Subtotal:	$	48,340,575	$	48,340,575
Reconciliation of Reservation Charges:	**$**	**257,733,108**	**$**	**260,790,942**

2.13 Review of Benchmark Commodity Indices

Table 2-14 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 2-14
Pacific Gas and Electric Company
PG&E City Gate Indices
CPIM Year 20
November 1, 2012 through October 31, 2013

	Ruby Rockies	AECO	San Juan	Kingsgate	Kern River	Topock	PG&E Citygate Daily
Nov-12	3.52890	3.47809	3.50833	3.80739	3.57460	-	3.93
Dec-12	3.75112	3.63815	3.76640	3.96772	3.79862	3.60318	3.73
Jan-13	3.42990	3.29644	3.43567	3.59762	3.45991	3.60952	3.62
Feb-13	3.42299	3.14520	3.43567	3.44026	3.45578	3.59912	3.78
Mar-13	3.37237	3.20487	3.43567	3.50172	3.40437	-	4.23
Apr-13	3.97910	3.58981	3.98021	3.88598	4.00448	4.24102	4.33
May-13	4.06015	3.76674	4.14521	4.05955	4.07725	-	4.23
Jun-13	4.11081	3.67022	4.16583	3.95897	4.13707	-	3.80
Jul-13	3.62656	3.33923	3.72240	3.63341	3.63380	-	3.71
Aug-13	3.54527	2.79429	3.61928	3.08406	3.55149	-	3.96
Sep-13	3.46398	2.60541	3.55740	2.91635	3.47367	-	3.83
Oct-13	3.44958	2.67299	3.52586	2.97939	3.45246	3.91216	3.93

2.14 Examination of Benchmark Storage Charges 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 $260,790,942, which consisted of the Canadian pipeline demand charges of $31,147,750, U.S. interstate pipeline reservation costs of $127,146,104, California intrastate pipeline costs of $54,156,513, and storage costs of $48,340,575. Table 2-15 provides a summary of these costs.

TABLE 2-15
Pacifc Gas and Electric Company
Summary of Fixed Transport and Storage Costs
CPIM Year 20
November 1, 2012 through October 31, 2013

Benchmark Demand Charges			
Canadian			
Foothills Pipelines Ltd.			10,176,625
Nova Gas Transmission Ltd.			20,971,125
	Canadian Subtotal	$	31,147,750
Interstate			
Gas Transmission Northwest Corporation			42,163,536
El Paso Natural Gas Company			11,576,917
Kern River Gas Transmission			3,496,825
Ruby Pipeline			57,866,324
Transwestern Pipeline Company			12,042,502
	Interstate Subtotal		127,146,104
Intrastate			
California Gas Transmission Baja			26,120,434
California Gas Transmission Redwood			28,036,079
	Intrastate Subtotal	$	54,156,513
	Total Demand Charges	$	212,450,367
CA Intrastate Storage Costs:			
California Gas Transmission Firm Storage			
			45,988,831
Lodi Gas Storage, Inc.			
			2,322,000
			29,744
Total CA Storage Costs:		$	48,340,575
Total Transportation & Storage Costs:		$	260,790,942

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 from Canadian, U.S. interstate and California intrastate pipeline systems to meet core gas demand. During Year 20, PG&E transported these resources using firm transportation contracts. The summary in Table 2-16 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, 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 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.[13]

[13] PG&E Annual Performance Report, CPIM Year 20, dated June 13, 2014.

Table 2-16
Pacific Gas and Electric Company
Core Gas Supply - Utilization of Interstate, Intrastate and Canadian Pipeline Assets
CPIM Year 20
November 1, 2012 through October 31, 2013

Pipeline Capacity:	Quantity (Dth/d)	Contract Expiration Date	Utilization Rate
TransCanada Pipelines:			
NGTL	287,745	10/31/16	
	82,223	10/31/20	
Total NOVA:	369,968		100%
Foothills-BC System	284,810	10/31/15	
	81,384	10/31/15	
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	66,000	06/30/13	
	85,739	06/30/13	
	30,000	06/30/14	
Total El Paso Natural Gas:	Varies		97%
Transwestern Pipeline Co.	150,000	03/31/13	
	142,970	03/31/15	
Total Transwestern Pipeline Co:	292,970		99%
Ruby	250,000	10/31/26	84%
Kern River	50,033	06/30/13	
	10,000	06/30/14	
	Varies		100%
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:	Varies		74%

Appedix A Exhibits For CPIM Year 20		
Section	**Descriptioin**	**Exhibit Number**
Reward Calcuation 2-1		
	CPIM Tolerance Band Calculation	2-A
	CPIM Performance	2-A1
	Monthly Actual Cost Total	2-B
	Monthly Benchmark Cost Total	2-B1
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/Demand Charge	2-D
	Reservation Charge Discount	2-D1
Storage/Inventory 2-6		
	Firm Storage Inventory	2-H
	Storage Cost	2-D4
	Injection/Withdraw Charge	2-D5
Miscellaneous Costs 2-7		
	Miscellaneous Costs and Revenues	2-C4
	Capacity Release Revenue	2-D2
	Capacity Release Discount (Premium)	2-D3
Hedge Cost 2-8		
	Financial Derivatives Costs	2-C5
	Benchmark Winter Hedge Cost	2-C6
	Actual Winter Hedge Cost	2-C7