PACIFIC GAS AND ELECTRIC COMPANY

CORE PROCUREMENT INCENTIVE MECHANISM (CPIM)
Application 96-08-043

November 1, 2009 through October 31, 2010
CPIM ANNUAL PERFORMANCE REPORT
CPIM Year 17

Before the Public Utilities Commission
of the
State of California
March 16, 2011

PUBLIC VERSION

Pacific Gas and Electric Company

CPIM Annual Performance Report

Year 17

November 1, 2009 through October 31, 2010

1. Introduction

This report, filed with the California Public Utilities Commission (Commission) in compliance with Decision (D.) 97-08-055,[1] documents the performance of Pacific Gas and Electric Company (PG&E) under the Core Procurement Incentive Mechanism (CPIM) for the period November 1, 2009, through October 31, 2010 (CPIM Year 17).[2] During CPIM Year 17, PG&E served its core gas customers reliably and in a manner that resulted in total costs that were $33,578,338 below the CPIM benchmark, delivering substantial savings to its customers. PG&E's core gas customers receive 100% of the gas cost savings within the CPIM "Tolerance Band," and 80% of the savings below the "Lower Limit" of the "Tolerance Band." PG&E shareholders receive 20% of the savings below the "Lower Limit" of the "Tolerance Band." During CPIM Year 17, PG&E's core gas customers received total savings of $29,283,101. In accordance with the CPIM savings sharing formula, PG&E requests a shareholder award of $4,295,237.

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[1] PG&E's Gas Accord Application (A.) 96-08-043, Supplemental Report Describing the Post-1997 Core Procurement Incentive Mechanism, October 18, 1996. In D.97-08-055, the Commission approved a CPIM mechanism for core gas costs incurred after December 31, 1997 (Post-1997 CPIM). In that decision, the Commission ordered PG&E to file quarterly and annual reports on core procurement operations commencing 30 days after completion of one year of Gas Accord operating experience (Sixth Interim Order, D.97-08-055, at *mimeo*, pp. 65, and Ordering Paragraph 10).

[2] PG&E's Gas Accord Application (A.) 96-08-043, Supplemental Report Describing the Post-1997 Core Procurement Incentive Mechanism, October 18, 1996.

The CPIM Annual Performance Report provides the Division of Ratepayer Advocates (DRA) and the Commission's Energy Division an opportunity to review PG&E's core procurement costs, the calculation of savings to core gas customers, and the calculation of the resulting shareholder award. In addition, the report, excluding confidential Appendix A, is provided to all parties in Application (A.) 09-09-013 (PG&E's Gas Transmission and Storage 2011 Rate Case). The reporting, evaluation, and approval process described below is consistent with the procedures utilized in PG&E's previous CPIM periods.

2. CPIM Overview

The CPIM provides PG&E with a direct financial incentive to procure and manage gas supplies and transportation at the lowest reasonable cost by calculating shareholder awards or penalties through comparisons of total gas costs to a market-based composite benchmark described in Section 5 below. PG&E's performance is calculated annually, and any associated shareholder award or penalty is then recorded in the Core Sales Subaccount of the Purchased Gas Account (PGA).

The CPIM provides a standard benchmark that applies to purchasing activities occurring under most operating and temperature conditions. An alternate benchmark may be invoked under extraordinary circumstances of extremely heavy core demand or significant supply shortfalls. CPIM Year 17 did not utilize the alternate benchmark and therefore, only the standard benchmark is reflected in this report.

3. Procedural Background and Recent Modifications

On August 1, 1997, the Commission issued D.97-08-055 (the Gas Accord Decision), which approved recovery of PG&E's core gas procurement, storage and transportation costs in customer rates for the period January 1, 1998, to December 31, 2002.[3] In D. 02-08-070 (the Gas Accord II Decision) and D.03-12-061, the Commission extended the recovery of core gas procurement, storage and transportation costs (by way of the CPIM), and set the extension to terminate on the earlier of, (1) December 31, 2005; or (2) when a revised CPIM was adopted by the Commission. In the proceeding requiring the California energy utilities to preserve interstate pipeline capacity to California (Rulemaking (R.) 02-06-041), PG&E and DRA reached a stipulation and agreement that addressed modifications to PG&E's CPIM, including a provision that: "[t]he CPIM will continue until either DRA or PG&E proposes modifications and those modifications are approved by the Commission." This stipulation and agreement, which is Exhibit 1 of R.02-06-041, was approved by the Commission in D.04-01-047, at mimeo p. 21 and Finding of Fact 12. The Commission's decision in D.04-12-050 (the Gas Accord III Decision) made no substantive changes to the CPIM (D.04-12-050, at mimeo p. 17-18 and Conclusion of Law 8).

Core portfolio cost recovery is to be consistent with the PG&E/DRA Post-1997 CPIM Agreement dated October 16, 1996 (Post-1997 CPIM Agreement); PG&E's Supplemental Report Describing the Post-1997 CPIM, dated October 18, 1996 (Supplemental Report), filed in A.96-08-043 and approved in D.97-08-055; and the

[3] Appendix 1 to the Gas Accord Settlement Agreement, p. 57, filed with the Commission on August 21, 1996, indicated that PG&E would file a CPIM mechanism applicable to the Gas Accord period. Appendix 1 was incorporated into D.97-08-055 (see D.97-08-055, Appendix B).

Memorandum of Understanding (DRA/PG&E MOU) addressing certain procedural details (attached as Appendix A in the 1999 report). Additional modifications were adopted by the Commission in D.04-01-047, accommodating additional pipeline capacity and addressing other changes as agreed to by DRA, The Utility Reform Network (TURN), and PG&E.[4]

a. CPIM Hedging Settlement Agreement

Effective November 1, 2010, in accordance with the CPIM Hedging Settlement Agreement approved by the Commission in D.10-01-023, future winter hedges implemented to protect PG&E's core gas customers against extreme winter price spikes are to be included in the CPIM. Eighty percent (80%) of the net realized gains or losses and associated transaction costs will be included in the CPIM benchmark, while 100% of the net realized gains or losses and associated transaction costs will be included in the actual cost side of the CPIM. These changes are effective for all hedging transactions executed by PG&E on or after November 1, 2009 for CPIM years beginning on or after November 1, 2010.[5]

During CPIM Year 17, PG&E engaged in hedging transactions which will settle during CPIM Year 18. The details of these transactions will be provided to DRA in future reports, in accordance with the CPIM Hedging Settlement Agreement. In addition, hedging transactions previously authorized under the Long Term Core Hedge Program (D.07-06-013) settled during CPIM Year 17. The costs and benefits

[4] The Commission adopted changes to utilities' gas cost incentive mechanisms to accommodate pre-existing and newly acquired interstate capacity by utilities in compliance with D.02-07-037. In D.04-01-047, the Commission also adopted the stipulations.
[5] D.10-01-023.

of these transactions remain outside of CPIM. PG&E submitted monthly position reports throughout CPIM Year 17, and discussed these activities with DRA during monthly conference calls.

4. CPIM Year 17 Performance Results

For CPIM Year 17, the aggregate gas cost benchmark was $1,480,687,740 and actual gas costs were $1,447,109,403, or 97.7 percent of the aggregate benchmark. As specified by the CPIM, Chapter 2, Part III, Incentive Rewards and Penalties,[6] and by PG&E's Gas Preliminary Statement Part C, all gas cost savings that are below the "Lower Limit" of the "Tolerance Band" are subject to sharing between core gas customers and PG&E shareholders.

Table I shows that the actual gas costs are $33,578,338 below the CPIM benchmark and $21,476,184 below the "Lower Limit" of the "Tolerance Band", yielding a shareholder award of $4,295,237. PG&E requests that DRA confirm the gas cost benchmark and performance calculations and recommend to the Commission that PG&E's shareholders be awarded $4,295,237.

[6] The shareholder incentive award formula is described in the CPIM, Chapter 2, Part III, Section B, Sharing Outside of the Tolerance Band. The Commission approved modifications to this formula are in the Settlement Agreement dated December 15, 2006, and D.07-06-013 dated June 7, 2007, effective in CPIM Year 15.

Table I

CPIM Performance Summary
November 1, 2009 – October 31, 2010

Total Commodity, Transportation and Storage Costs						
Zone of Reasonableness			Actual Costs			
Upper Tolerance Limit (Benchmark + 2.0% Commodity Benchmark)	Total Benchmark	Lower Tolerance Limit (Benchmark – 1.0% Commodity Benchmark)	Total Costs Incurred	Amount Under Benchmark	Amount Under Tolerance Band	Shareholder Award
$1,504,892,048	$1,480,687,740	$1,468,585,586	$1,447,109,403	$33,578,338	$21,476,184	$4,295,237

PG&E's Core Gas Supply Year 17 Monthly CPIM Summary, provided in Table II below, summarizes monthly gas costs, benchmarks, tolerance band limits, and resulting performance relative to the benchmarks. Appendix A, which is submitted to the DRA and Energy Division on a confidential basis under General Order 66-C and the Public Utilities Code Section 583, contains detailed monthly cost information upon which Table II, the Monthly CPIM Summary, is based.

Table II

Pacific Gas and Electric Company
Core Gas Supply
Cumulative Monthly CPIM Year 17 Report
November 1, 2009 - October 31, 2010

	INTERSTATE AND CALIFORNIA GAS PURCHASES (1)			RESERVATION CHARGES (2)		TOTAL CPIM PERFORMANCE					
	Commodity		Benchmark -	Pipeline Charges		Total		Benchmark -	Tolerance Band		(Over)/Under
Month	Actuals	Benchmark	Actuals	Actuals	Benchmark	Actuals	Benchmark	Actuals	"Upper Limit" (3)	"Lower Limit" (4)	Tolerance Band
Nov-09	$107,944,949	$112,717,408	$4,772,459	$19,939,840	$20,619,619	$127,884,789	$133,337,027	$5,452,238	$135,591,375	$132,209,853	$4,325,064
Dec-09	157,052,676	155,620,615	(1,432,061)	22,821,178	23,972,546	179,873,854	179,593,161	(280,693)	182,705,573	178,036,955	Within
Jan-10	161,191,724	157,492,102	(3,699,622)	24,841,126	25,064,044	186,032,851	182,556,146	(3,476,704)	185,705,988	180,981,225	(326,863)
Feb-10	124,086,091	126,510,462	2,424,371	24,095,402	24,307,776	148,181,493	150,818,238	2,636,745	153,348,447	149,553,133	1,371,640
Mar-10	127,933,010	129,948,888	2,015,878	22,085,050	22,139,440	150,018,060	152,088,328	2,070,268	154,687,306	150,788,839	770,779
Apr-10	115,071,556	118,349,264	3,277,708	22,077,848	22,112,798	137,149,404	140,462,062	3,312,658	142,829,047	139,278,569	2,129,165
May-10	84,999,140	86,040,845	1,041,705	20,992,889	22,063,603	105,992,029	108,104,448	2,112,419	109,825,265	107,244,040	1,252,011
Jun-10	63,031,585	65,285,656	2,254,071	20,171,139	22,006,986	83,202,724	87,292,642	4,089,918	88,598,355	86,639,785	3,437,061
Jul-10	68,159,671	70,219,394	2,059,723	20,091,326	22,569,208	88,250,997	92,788,602	4,537,605	94,192,990	92,086,408	3,835,411
Aug-10	66,599,997	67,669,431	1,069,434	18,643,488	21,524,171	85,243,485	89,193,602	3,950,118	90,546,991	88,516,908	3,273,424
Sep-10	53,383,651	54,642,318	1,258,667	19,087,546	21,530,015	72,471,197	76,172,333	3,701,136	77,265,179	75,625,910	3,154,713
Oct-10	61,275,353	65,719,031	4,443,678	21,533,167	22,562,120	82,808,520	88,281,151	5,472,631	89,595,532	87,623,961	4,815,441
Total	$1,190,729,402	$1,210,215,414	$19,486,012	$256,379,999	$270,472,326	$1,447,109,403	$1,480,687,740	$33,578,338	$1,504,892,048	$1,468,585,586	$21,476,184
						2010 (Year 17) Shareholder Earnings/(Loss)					$4,295,237

(1) Canadian and U.S. gas commodity costs. Volumetric costs to PG&E's Citygate are included.
(2) Includes intrastate, applicable interstate and Canadian pipeline reservation charges net of capacity release revenue.
(3) "Upper Limit" = Benchmark + 2.0% of Commodity Benchmark
(4) "Lower Limit" = Benchmark - 1.0% of Commodity Benchmark

5. <u>How the Standard Benchmark is Determined</u>

The CPIM standard benchmark is made up of three components:

1) Fixed transportation costs which include Canadian, U.S. interstate, and California intrastate capacity reservation costs;

2) Variable costs which include commodity costs, Canadian, U.S. interstate, and California intrastate pipeline fuel and volumetric capacity costs; and

3) Storage costs which include both the fixed reservation charges and variable costs.

The total benchmark, composed of fixed and variable costs, is compared to total gas costs, transportation costs, and storage costs for the applicable CPIM period.

As more fully described in Section 3 above, winter hedging costs will be included in the CPIM beginning in Year 18. No hedging costs are included in CPIM Year 17.

The specific benchmark components are described below.

a. Fixed Transportation Component

The fixed transportation component of the benchmark is composed of capacity reservation costs associated with PG&E's firm capacity holdings on the following pipeline systems:

1. TransCanada Pipelines Limited (TransCanada) – NOVA Gas Transmission Ltd. (NGTL);

2. TransCanada – Foothills Pipe Lines, Ltd. (Foothills);

3. TransCanada – Gas Transmission Northwest Corporation (GTN);

4. El Paso Natural Gas Company;

5. Transwestern Pipeline Company (Transwestern); and

6. PG&E's California Gas Transmission (CGT).

The daily contract quantities for each pipeline during CPIM Year 17 are shown in Table III of this report.

Revenue from the release of unused capacity is credited against actual costs. The costs of interstate capacity, intrastate capacity and storage capacity offered to and accepted by Core Transport Agents (CTAs) for gas commodity service provided through core aggregation are not included in the CPIM benchmark or actual costs. Those costs are recovered directly from CTAs, as provided by D.97-12-032 and PG&E's Schedule G-CT - Core Gas Aggregation Service.

b. Variable Cost Component

The variable cost component of the benchmark represents the cost of gas, including fuel and volumetric transportation charges from the supply region, delivered to the

PG&E Citygate (where PG&E's backbone transmission system connects to the local distribution system). The benchmark is based upon the forecasted level of daily demand, adjusted for an agreed-upon amount of storage injection or withdrawal, as described below in Section 5(c). The storage-adjusted demand is allocated among the various transportation paths available to the core gas customers based on an established sequence of supply acquisition as set by the CPIM. The allocated amounts are then multiplied by the appropriate gas cost index associated with the specific transportation path. The total forms a daily commodity benchmark. The daily benchmark amounts are summed to establish the annual benchmark.

c. Storage Cost Component

The benchmark includes a monthly storage reservation cost at the tariff rate set for the Core's capacity. The storage cost component of the benchmark is described in Appendix B of D.97-08-055, page 18, and modified by the DRA – PG&E Stipulation(s) as approved in D.04-01-047.[7] The storage component includes the storage reservation costs at the as-billed rate for (i) 33.5 million decatherms (MMDth) of inventory, (ii) 115 to 207 thousand decatherms (MDth) per day of summer injection, and (iii) 970 to 1,253 MDth per day of winter withdrawal capacity, adjusted for CTA elections. The CPIM storage profile establishes daily and monthly benchmark allocations of injection and withdrawal. The current profile was established by an agreement between DRA and PG&E on October 19, 2009, and this agreement was provided as Appendix B in the CPIM Year 16 Annual

[7] See Footnote 4.

Performance Report. This modified profile became effective in CPIM Year 17 and will apply to all subsequent CPIM years. PG&E's Gas Schedule G-CFS provides the rate and operational details of the firm storage service for PG&E's core gas customers.

d. Liquids Extraction Revenue

Any gas by-products extraction revenues are credited against gas costs under the CPIM, with no adjustment to benchmark dollars.[8] In CPIM Year 17, PG&E earned $12,142,892 in liquids extraction revenue attributable to gas transportation on the TransCanada – NGTL system.

6. Canadian and U.S. Pipeline Capacity Holdings

As described in the *Fixed Transportation Component* of Section 5 above, PG&E holds Canadian, U.S. interstate, and California intrastate capacity for the core gas portfolio. PG&E is authorized to recover the costs associated with its Canadian and U.S. interstate capacity through approval procedures specified in D.04-09-022.[9]

PG&E's Core Gas Supply is allocated firm intrastate capacity to transport supplies for the core portfolio according to PG&E's Gas Accord III (A.04-03-021), and is authorized to recover such costs under D.04-12-050.[10] PG&E's Baja Path quantities were modified by D.07-07-002, dated July 12, 2007, and as a result the annual Baja Path capacity

[8] See Footnote 1. (Section VI "Additional Features." Part A – Gas Sales/Capacity Brokering Revenue.)
[9] D.04-09-022, Order Instituting Rulemaking to establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California, September 2, 2004.
[10] Ordering Paragraph 1, at *mimeo*, p. 25, approves and adopts all rates and services.

allocated to PG&E's core is 348 MDth per day and the winter seasonal Baja Path capacity (December through February) is 321 MDth per day. Thus, the maximum combined annual and winter seasonal Baja core capacity holdings are 669 MDth per day.

a. Canadian and U.S. Interstate Pipeline Capacity Changes

PG&E's Core Gas Supply utilized the winter seasonal pipeline capacity it acquired in CPIM Year 16 under the pre-approval process and procedures established in D.04-09-022 during CPIM Year 17. This seasonal capacity was contracted for three consecutive winters (2009-2010, 2010-2011, and 2011-2012) and is detailed below in Table III. All approved capacity costs are recovered from PG&E's core gas customers through the PGA in accordance with D.04-09-022, the Core Pipeline Demand Charge Account (CPDCA), and PG&E's gas tariffs. The capacity transactions are described below.

• <u>Transwestern Pipeline Company</u>

On March 5, 2010, PG&E submitted expedited Advice Letter 3100-G requesting approval for a two-year Transwestern contract extension for 150,000 decatherms (Dth) per day beginning April 1, 2011. PG&E's Core Gas Supply received Energy Division approval of Advice Letter 3100-G on March 23, 2010.

As shown in Table III, PG&E holds a maximum annual quantity of 150,000 Dth per day through one Transwestern contract. In addition, PG&E held a winter seasonal

(December 1, 2009 – February 28, 2010) quantity of 76,720 Dth per day during CPIM Year 17.

• TransCanada – NGTL, Foothills, and GTN Contracts

On September 24, 2010, PG&E submitted expedited Advice Letter 3153-G requesting approval to extend two of its three existing contracts on NGTL. PG&E's Core Gas Supply received Energy Division approval of Advice Letter 3153-G on October 21, 2010.

The first contract for 249,401 Dth per day expires on October 31, 2011; the second contract for 287,745 Dth per day expires on October 31, 2016; and the third contract for 82,223 Dth per day expires on October 31, 2020.[11] Furthermore, the multi-year contract extensions receive a 10% term differentiated reservation rate discount.

Advice Letter 3153-G also approved a one-year contract extension for two contracts totaling 366,194 Dth per day on Foothills. These new Foothills contracts terminate on October 31, 2012.

Table III below, shows the interstate and intrastate pipeline capacity contract quantities and the average capacity utilization for each contract during CPIM Year 17.

[11] Contract quantities are stated in gigajoules (GJ) per day.

Table III

PG&E Core Gas Supply Pipeline Assets

Interstate and Canadian Pipeline Assets and Utilization

Pipeline	Description	Quantity (Dth/d)	Expiration Date	Approx.% Utilization (1)
NGTL (1)	2010433015	249,401	10/31/2011	
	2010433016	287,745	10/31/2016	
	2010433017	82,223	10/31/2020	
Total NGTL		**619,369**		100%
Foothills – BC System	PGE-F1	244,860	10/31/2011	
	PGE-F3	284,810	10/31/2012	
	PGE-F4	81,384	10/31/2012	
Total BC System		**611,054**		100%
GTN	10523	250,000	10/31/2011	
	10524	279,968	10/31/2016	
	10525	80,000	10/31/2020	
Total GTN		**609,968**		98%
El Paso	9RJE	116,035	6/30/2012	
	9RJG	85,739	6/30/2013	
Total El Paso		**201,774**		89%
Transwestern	101629 / 102769	**150,000**	3/31/2013	98%
Seasonal 09-10 (Dec. – Feb.)		**76,720**	2/28/2010	
Seasonal 10-11 (Dec. – Feb.)		26,720	2/28/2011	
Seasonal 11-12 (Dec. – Feb.)		43,220	2/29/2012	

Utilization of Intrastate Pipeline Assets

Pipeline	Description	Quantity (Dth/d)	Expiration Date	Approx. % Utilization (1)
PG&E's California Gas Transmission				
Silverado		**1,000**		100%
Redwood		**608,766**		100%
Baja				86%
Annual		348,000		
Seasonal (Dec. – Feb.)		321,000		
Total Baja		**669,000**		

(1) Utilization is the percentage of capacity used to transport supplies or release to other parties, and includes seasonal capacity.

b. Proposed Intrastate Pipeline Capacity Changes

As described in PG&E's CPIM Year 16 Annual Performance Report, PG&E's Core Gas Supply sponsored testimony in PG&E's 2011 Gas Transmission and Storage Rate Case proceeding, A.09-09-013, proposing to decrease Core's winter seasonal Baja Path capacity by 100 MDth per day, from 321 to 221 MDth per day, beginning on March 1, 2011. PG&E also proposed elimination of the Core's existing allocation of annual firm Silverado Path capacity. The Silverado capacity was originally held to take delivery of gas contracted to PG&E's Core Gas Supply under long-term traditional California gas production contracts, which have since expired. The Division of Ratepayer Advocates (DRA) opposed the decrease of winter Baja capacity, and on October 8, 2010, PG&E and the Settling Parties, including DRA, submitted Gas Accord V to the Commission, which among other things, retains the existing quantity of Core's winter seasonal Baja capacity, but eliminates the Silverado capacity. The Gas Accord V Settlement is currently awaiting decision before the Commission under A.09-09-013. If approved by the Commission, the elimination of the Silverado capacity will become effective during CPIM Year 18.

8. Efforts to Provide Benefits and Protect Core Customers

The CPIM encourages PG&E to proactively lower core gas costs through physical and financial transactions and through use of storage and pipeline capacity. PG&E endeavors to minimize costs by optimizing its gas purchases and assets while maintaining a high degree of supply reliability. As described in Section 1 and Section 4, PG&E obtained significant gas cost savings for its core customers during CPIM Year 17. PG&E achieved these savings by effectively managing the use of the assets assigned to PG&E's Core Gas Supply, including storage inventory, injection and withdrawal rights, Canadian, U.S. interstate and intrastate pipeline capacity rights. PG&E lowered overall gas costs by monetizing these assets when not needed for core reliability. This included releasing pipeline capacity, selling gas when not needed to meet daily core demands, using storage when gas demand or prices were high, and carefully managing pipeline receipts and deliveries to avoid imbalance penalties.

In addition to the above physical activities during CPIM Year 17, and as discussed previously in Section 3, PG&E also employed a winter hedging strategy to protect core customers from potential extreme gas cost spikes during the peak winter months when core usage is typically the highest.

9. Conclusion

PG&E's annual CPIM performance report concludes that PG&E's core gas costs, as measured against the aggregate CPIM benchmark during the period November 1, 2009 through October 31, 2010 (CPIM Year 17), are below the annual CPIM benchmark by $33,578,338. The total recorded gas costs should be deemed reasonable and recoverable from PG&E's core customers. In accordance with the incentive award formula, PG&E requests a shareholder award of $4,295,237.

Appendix A

Core Procurement Incentive Mechanism

Performance Report Monthly Detail

CPIM Year 17

Submitted to DRA and the Energy Division

Under General Order 66-C and

Public Utilities Code, Section 583