GAS PRELIMINARY STATEMENT PART C Sheet 1
GAS ACCOUNTING TERMS & DEFINITIONS

FC. GAS ACCOUNTING TERMS AND DEFINITIONS

These accounting terms and definitions are used in the authorized gas revenue requirements and surcharge funding as well as the accounting procedure descriptions that follow in this Preliminary Statement. They are consistent with and apply to PG&E's Gas Rate Schedules and Rules. Additional definitions can be found in Rule 1.

1. BALANCING ACCOUNT: In the context of this tariff, a balancing account is an account in which:

   a. expenses are compared with revenues from rates designed to recover those expenses, or

   b. forecast expenses are compared with recorded expenses, or

   c. forecast revenues are compared with recorded revenues, or

   d. authorized funding is compared to surcharge amounts.

   The resulting under- or overcollection, plus interest, is recorded on PG&E's financial statements as an asset or liability, which is owed from or due to the ratepayers. Balances in balancing accounts, plus interest, are to be amortized in rates.

BASE REVENUE AND AUTHORIZED FUNDING AMOUNTS: The GRC Distribution Base Revenue Amount is the annual operating revenue, less other operating revenue adopted in the General Rate Case (GRC) or other proceedings.

Adjustments and credits to GRC Base Revenues were approved in various CPUC decisions. In Decision 05-06-029, the CPUC adopted specific levels of Enhanced Oil Recovery (EOR) revenue. In Decision 04-12-050, the CPUC revised the core brokerage fee authorized in Decision 97-08-055. Adjustments for G-10 employee discounts are revised when the CPUC authorizes revisions to illustrative residential core procurement rates in the BCAP or other proceedings. The currently effective GRC Distribution Base Revenue Amount (with adjustments and credits) is shown in Table C.2.

The Gas Transmission and Storage (GT&S) Base Revenues are comprised of Local Transmission, Backbone Transmission, Storage and transmission-level customer access adopted in GT&S Decision 16-12-010. The currently effective GT&S Revenue Requirement is shown in Table C.2.

The Public Purpose Program (PPP) authorized funding includes amounts for Energy Efficiency (EE) and Low Income Energy Efficiency (LIEE) Programs, public interest Research, Development and Demonstration (RD&D), State Board of Equalization (BOE) and CPUC Surcharge Administration Fees, California Alternate Rates for Energy (CARE) Administrative Expenses and CARE shortfall. PPP-authorized funding and the subsidy for CARE customers are recovered through the gas PPP surcharge, as authorized by Public Utilities Code Sections 890-900, Resolution G-3303 and Decision 04-08-010.* The currently authorized PPP funding amounts are shown in Table C.2.

---

* Decision 04-08-010 determined that Revenue Fees and Uncollectible (RF&U) accounts expense should not be included in the calculation of gas PPP surcharges. (T)

(Continued)

GAS PRELIMINARY STATEMENT PART C Sheet 2
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

Description	Core		Noncore		Unbundled	Core Procurement	Total	
					Amount ($000)			
BASE REVENUES (incl. RF&U) :								
Authorized GRC Distribution Base Revenue (1)							2,799,971	
Pension - Distribution (2)							34,878	
GRC Distribution Base Revenue Undercollection							62,100	
Less: Other Operating Revenue							(33,586)	
Authorized Distribution Revenues	2,893,202		108,650				3,001,852	
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:								
G-10 Procurement-Related Employee Discount	(843)						(843)	
G-10 Procurement Discount Allocation	344		499				843	
Core Brokerage Fee Credit	(5,332)						(5,332)	
Distribution Base Revenue with Adj. and Credits	2,887,371		109,149				2,996,520	
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):								
Transportation Balancing Accounts	(55,763)	(I)	44,433	(I)			(11,329)	(I)
Self-Generation Incentive Program Revenue Requirement	12,990		0				12,990	
CPUC Fee	2,701		2,342				5,043	
Pension – Gas Transmission & Storage (GT&S)	10,150		6,473				16,623	
Greenhouse Gas Obligation Cost	14,068		20,441				34,509	
Greenhouse Gas Compliance Cost	477,845		100,119				577,963	
Greenhouse Gas Allowance Proceeds Return	(440,354)		0				(440,354)	
Revenue Fees and Uncollectible (RF&U) accounts expense (on items above)	6,794	(I)	2,512	(I)			9,305	(I)
CARE Discount included in PPP Funding Requirement	(179,356)						(179,356)	
CARE Discount not included in PPP Surcharge Rates	0						0	
Transportation Forecast Period Costs & Balancing Account Balances	(150,925)	(I)	176,319	(I)			25,394	(I)
GT&S REVENUE REQUIREMENT (incl. RF&U) (4):								
Local Transmission	929,600		431,071				1,360,672	
Customer Access Charge – Transmission			3,740				3,740	
Storage	27,215				-		27,215	
Carrying Cost on PG&E Working Gas in Storage	0				-		0	
Backbone Transmission/L-401	229,676				319,584		549,260	
GT&S Revenue Requirement	1,186,492		434,811		319,584		1,940,887	

(1) The amount includes the authorized distribution base revenue approved in GRC D.23-11-069 and updated for the 2024 uncollectibles factor as determined in Advice 4839-G.

(2) The calculation of the 2023 pension RRQ reflects the capitalization and functional labor ratios approved in the 2023 GRC D.23-11-069. See also Advice 4840-G.

(3) The SGIP revenue requirement was authorized in D.17-04-017.

(4) The 2024 Gas Transmission & Storage Revenue Requirement as adopted in D.23-11-069.

Note: Totals may not add due to rounding.

(Continued)

GAS PRELIMINARY STATEMENT PART C Sheet 3
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)
2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

	Amount ($000)				
Description	Core	Noncore	Unbundled	Core Procurement	Total
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):					
Illustrative Gas Supply Portfolio				622,179	622,179
Interstate and Canadian Capacity				110,000	110,000
RF&U (on items above and Procurement Account Balances Below)				10,057	10,057
Backbone Capacity (incl. RF&U)	(163,073)			163,073	0
Backbone Volumetric (incl. RF&U)	(66,603)			66,603	0
Storage (incl. RF&U)	(27,215)			27,215	0
Carrying Cost on PG&E Working Gas in Storage (incl. RF&U)	-			-	0
Core Brokerage Fee (incl. RF&U)				5,332	5,332
Procurement Account Balances					
Illus. Core Procurement Revenue Requirement	(256,891)			1,004,458	747,567
TOTAL GAS REVENUE REQUIREMENT (without PPP)	3,666,048 (I)	720,280 (I)	319,584	1,004,458	5,710,369 (I)
GT&S LATE IMPLEMENTATION REVENUE REQUIREMENT (7):					
Local Transmission	259,945 (I)	120,234 (I)			380,179 (I)
Backbone	(891) (I)	(17,344) (I)			(18,235) (I)
Storage	15,679 (I)	-			15,679 (I)
Total GT&S Late Implementation Revenue Requirement	274,733 (I)	102,890 (I)			377,623 (I)
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (RF&U exempt) (6):					
Energy Efficiency (EE)	70,391	32,160			102,551
Energy Savings Assistance (ESA)	80,726	-			80,726
Research, Demonstration and Development	6,041	4,453			10,494
CARE Administrative Expense	1,511	1,303			2,814
Statewide Marketing, Education & Outreach	-	-			-
BOE and CPUC Administrative Cost	240	177			417
PPP Balancing Accounts	8,107	15,071			23,178
CARE Discount Recovered from non-CARE customers	96,298	83,058			179,356
Total PPP Funding Requirement in Rates	263,314	136,222			399,536
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT	4,204,095 (I)	959,392 (I)	319,584	1,004,458	6,487,528 (I)

(5) The credits shown in the Core column represent the core portion of the Gas and Transmission & Storage RRQ that is included in the illustrative Core Procurement RRQ and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly.
(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2024 PPP Surcharge AL 4822-G; and includes ESA program and CARE annual administrative expense funding adopted in D.21-06-015, and EE program funding adopted in D.23-06-055, excluding RF&U per D.04-08-010.

Note: Totals may not add due to rounding.

(Continued)

GAS PRELIMINARY STATEMENT PART C Sheet 4
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

3. COST ALLOCATION FACTORS:

a. General: These factors are derived from the allocation policies adopted in the last Cost Allocation Proceeding and are used to allocate recorded costs to customer classes.

	Factor			
Cost Category	Core	Noncore	Unbundled Storage and System Load Balancing	Total
Distribution Base Revenue Requirements	0.963807 (R)	0.036193 (I)		1.000000
Intervenor Compensation	0.963807 (R)	0.036193 (I)		1.000000
Other – Equal Distribution Based on All Transportation Volumes	0.407663 (R)	0.592337 (I)		1.000000
Carrying Cost on PG&E Working Gas in Storage	0.433962		0.566038	1.000000
ARB AB32 Cost of Implementation Fee	0.523528 (R)	0.476472 (I)		1.000000
Self Generation Incentive Program	1.000000 (I)	0.000000 (R)		1.000000

b. Pacific Gas and Electric Gas Transmission Northwest (PG&E GT-NW) and Intrastate Pipeline Demand Charges: Factors are derived based on the procedures defined in Decisions 91-11-025 and 97-05-093.

1) The core procurement factor will be equal to the capacity reserved for core procurement customers on each pipeline divided by the total capacity held by PG&E on that pipeline.

2) The core transport factor will be equal to the capacity reserved for core transport customers on each pipeline divided by the total capacity held by PG&E on that pipeline.

4. COST ALLOCATION PROCEEDING: The proceeding in which the Transportation Revenue Requirement, as described in Section C.10.c below, and the gas PPP authorized funding, as described in Section C.11. below, is allocated between customer classes. This proceeding is currently a biennial proceeding pursuant to CPUC Decision 90-09-089.

5. FORECAST PERIOD OR TEST PERIOD: The 24-month period, beginning with the revision date as specified in the Cost Allocation Proceeding.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

6. REVENUE FEES AND UNCOLLECTIBLE: See Gas Rule 1 for definition

   The RF&U factor is equal to ....1.013332 (R)

7. GAS SUPPLY PORTFOLIO: This portfolio includes the cost of gas procured by PG&E for its Core Portfolio (Core Procurement) customers. The costs and payouts for hedge instruments transacted under the core gas hedging plans, as approved in Decision 05-10-015 (effective October 6, 2005), Decision 06-08-027 (effective August 24, 2006), and Decision 07-06-013 (effective June 7, 2007) are included in the Gas Supply Portfolio, but are tracked separately. Gas Supply Portfolio costs are recovered through the Procurement Revenue Requirement described in Section C.10.d.

   Costs incurred for the portfolio include the cost of volumetric transportation, incremental pipeline capacity costs, imbalance transactions, hub services, incremental storage services, voluntary diversions, and emergency flow order (EFO) and operational flow order (OFO) charges and other portfolio-related services. These costs may be offset by revenue or gains from risk management tools such as derivative financial instruments (net of transaction costs), and other gas sales. Other transactions such as net revenue from imbalance transactions and byproducts extraction, expenses/losses from risk management tools, and pre-payments and credit and collateral payments, including all associated fees for gas procurement purchases, transportation, and related services, are included in the portfolio.

   The net cost of the “flowing supply” is the result of the transactions listed above. This portfolio also includes gas withdrawn from storage and excludes gas injected into storage for Core Procurement customers using the core storage reservation.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

8. CALIFORNIA ALTERNATE RATES FOR ENERGY (CARE) SHORTFALL: This shall be computed by subtracting CARE customers' monthly revenues from the revenues that would have been recovered from CARE customers had they been paying standard transportation and procurement rates.

9. MEMORANDUM ACCOUNT: In the context of this tariff, a memorandum account operates similar to a balancing account except that interest may be excluded and the under- or overcollection may or may not be amortized in future rates.

10. REVENUE REQUIREMENT: The revenue requirement consists of the sum of the Transmission and Storage Revenue Requirement which is set in PG&E's GT&S Decisions, and the Transportation and Procurement Revenue Requirements which are allocated in the Cost Allocation Proceeding, and are defined below. Rates will be established to recover all items in the revenue requirement.

    a. The Transmission System Revenue Requirement includes the Transmission portion of the GT&S base revenue amount,* load balancing storage costs, certain forecast amounts and RF&U. Amounts to be included in the Customer Class Charge paid by Transmission Service customers are allocated in the Cost Allocation Proceeding and described under Transportation Revenue Requirement, below. (T)

    b. The Storage Revenue Requirement includes the core and Unbundled Storage base revenue amount,* carrying costs on PG&E working gas in storage, load balancing gas, and RF&U. (T)

---

* See Section C.2 for details.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

c. The Transportation Revenue Requirement includes the core and noncore GRC Distribution Base Revenue Amounts (with credits and adjustments)*, forecast expenses, and balancing and memorandum account balances, with interest, as listed below. These amounts are recovered through distribution rates and the Customer Class Charge.

1) GRC Distribution Base Revenue Amount (with credits and adjustments): This shall be the GRC Distribution Base Revenue amount, with credits and adjustments as shown in Section C.2.

2) CPUC Reimbursement Fee Expense: This is the amount equal to the CPUC-adopted reimbursement rate, described in Preliminary Statement, Part O, multiplied by the total forecast period deliveries excluding interdepartmental, wholesale, interutility, and UEG deliveries.

3) Core Fixed Cost Account (CFCA) Balance: This is the forecast revision date balance in the CFCA, described in Preliminary Statement, Part F, based on the latest recorded data available.

(D)
I
(D)

4) Noncore Customer Class Charge Account (NCA) Balance: This is the forecast revision-date balance in the NCA, described in Preliminary Statement, Part J, based on the latest recorded data available. (T)

(D)
I
(D)

5) Hazardous Substance Mechanism (HSM) Balance: This is the forecast revision-date balance in the HSM, as described in Preliminary Statement, Part AN, based on the latest recorded data available. (T)

(Continued)

GAS PRELIMINARY STATEMENT PART C Sheet 8
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

c. Transportation Revenue Requirement (Cont'd.)

6) Customer Energy Efficiency Incentive Account (CEEIA) Balance: This is the forecast revision-date balance in the CEEIA, as described in Preliminary Statement, Part Y, based on the latest recorded data available. (T)

7) Core Brokerage Fee Balancing Account (CBFA) Balance: This is the forecast revision-date balance in the CBFA described in Preliminary Statement, Part U, based on the latest recorded data available. (T)

8) Affiliate Transfer Fees Account (ATFA) Balance: This is the forecast revision-date balance in the ATFA described in Preliminary Statement Part Q, based on the latest recorded data available. (T)

9) Self-Generation Program Memorandum Account (SGIP) Balance: This is the forecast revision-date balance in the SGIP described in Preliminary Statement, Part AW, based on the latest recorded data available. (T)

(D)
I
(D)

10) Revenue Fees and Uncollectible (RF&U) Account Expense: The amount to be added for RF&U shall be determined by multiplying the sum of Sections C.10.c.4.a through C.10.c.13, above, by the applicable RF&U factor. (T)

11) Transmission Integrity Management Program Balancing Account (TIMPBA) Balance: This is the forecast revision-date balance in the TIMPBA described in Preliminary Statement Part CL, based on the latest recorded data available. (T)

(D)
I
(D)

12) Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) Balance: This is the forecast revision date balance in the AMCDOP described in Preliminary Statement Part CO, based on the latest recorded data available. (T)

13) Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) Balance: This is the forecast revision-date balance in the GTSRSM described in Preliminary Statement Part CP, based on the latest recorded data available. (T)

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

d. Procurement Revenue Requirement includes the cost of gas from the Gas Supply Portfolio, pipeline capacity costs, intrastate transmission costs, the forecast revision-date balance in the Purchased Gas Account, and other procurement balancing accounts, the brokerage fee and core storage revenue requirements, plus RF&U, as applicable. (T)

1) Procurement Cost of Gas (Sales Only): The Procurement Cost of Gas is determined by multiplying the forecast core sales volume by the Weighted Average Cost of Gas (WACOG).

2) Procurement Cost of Gas (Shrinkage only): This cost-of-gas component shall be determined by multiplying the forecast shrinkage (LUAF & GDU) quantities for core procurement and core subscription customers by the weighted average cost of gas (WACOG). Customers who procure their own supplies are not responsible for this cost component; rather, they deliver shrinkage in-kind.

3) Pipeline Demand Charges: Pipeline Demand Charges include fixed demand and capacity charges from Canadian and FERC-regulated interstate pipelines.

4) Intrastate Transmission Charges: Intrastate Transmission Charges include capacity charges reserved for Core Portfolio customers on PG&E's Backbone Transmission System at the Modified Fixed Variable (MFV) tariff rate for core customers.

5) Carrying Cost on PG&E Working Gas in Storage: The Carrying Cost on PG&E Working Gas in Storage shall be determined by multiplying the forecast value of gas in storage during this forecast period, excluding gas owned by third parties, by the current interest rate on three-month Commercial Paper, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

6) Carrying Cost on Core's Cycled Gas in Storage: The Carrying Cost on Core's Cycled Gas in Storage shall be determined by multiplying the forecast value of gas in storage during this forecast period, excluding gas owned by third parties, by the current interest rate on three-month Commercial Paper, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

7) Purchased Gas Account (PGA): The revenue requirement will include the forecast revision-date balance in the PGA, described in Preliminary Statement, Part D, based on the latest recorded data available.

8) Core Pipeline Demand Charge Account (CPDCA): The revenue requirement will include the forecast revision-date balance in the CPDCA, described in Preliminary Statement, Part AE, based on the latest recorded data available.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

10. REVENUE REQUIREMENT (Cont'd.)

d. Core Procurement Revenue Requirement (Cont'd.)

9) Core Firm Storage Account (CFSA) Balance: The revenue requirement will include the forecast revision-date balance in the CFSA, described in Preliminary Statement, Part AG, based on the latest recorded data available.

10) Core Storage Revenue Requirement: This is the core storage amount shown in the GT&S base revenue in C.2, above.

11) Brokerage Fee Revenue Requirement: This is the amount credited to the GRC Distribution Base Revenues shown in C.10.c.1, above.

12) Revenue Fees and Uncollectible (RF&U) Accounts Expense: The amount to be added for RF&U shall be determined by multiplying the sum of C.10.d.1 through C.10.d.9, above.

(D)
I
(D)

11. PUBLIC PURPOSE PROGRAM AUTHORIZED FUNDING

Public Purpose Program (PPP) authorized funding includes the authorized amounts for Energy Efficiency (EE) and Low Income Energy Efficiency (LIEE) programs, public interest Research, Development & Demonstration (RDD), California Alternate Rates for Energy (CARE) Administrative Expenses, CARE shortfall expenses, and the forecast revision-date balances in the PPP balancing accounts. PPP authorized funding is recovered through the gas PPP surcharge.

1) PPP Authorized Amounts: This shall be the EE, LIEE, and RD&D authorized funding amount shown in Section C.2.

2) CARE Administrative Expense: This shall be the total CARE administrative expense expected to occur during the forecast period, as shown in Section C.2.

3) CARE Shortfall Expense: This shall be the total CARE shortfall expected to occur during the forecast period.

4) PPP-EE Balancing Account Balance: This is the forecast revision-date balance in the PPP EE described in Preliminary Statement, Part BA, based on the latest recorded data available.

5) PPP-LIEE Balancing Account Balance: This is the forecast revision-date balance in the PPP-LIEE described in Preliminary Statement Part BH, based on the latest recorded data available.

6) PPP-RDD Balancing Account Balance: This is the forecast revision-date balance in the PPP-RDD described in Preliminary Statement Part BI, based on the latest recorded data available.

7) PPP-CARE Balancing Account Balance: This is the forecast revision-date balance in the PPP-CARE, described in Preliminary Statement, Part V, based on the latest recorded data available.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

12. REVISION DATES: PG&E's application for the Biennial Cost Allocation Proceeding (BCAP) shall be filed based on a schedule set forth by the CPUC. PG&E's Procurement rate shall be updated monthly.

a. Core Procurement Rate Change

Per Decision 97-10-065, an advice filing to change core procurement rates will be filed monthly. The filing will update certain forecasted procurement costs and the amortization component of the procurement rate. PG&E will continue to provide a Weighted Average Cost of Gas (WACOG) forecast in its BCAP for ratemaking purposes.

Per Decision 03-12-008, noncore customers switching to core service are subject to a crossover procurement rate, as specified in Schedule G-CPX, for the first twelve (12) regular monthly billing periods. Schedule G-CPX is filed by advice letter monthly.

b. Annual Gas True-up of Balancing Accounts (AGT)

Per Decision 05-06-029, an advice filing to change core and noncore transportation rates will be filed 45 days prior to the end of each calendar year for rates effective January 1. The filing will update the customer class charge components of transportation rates to recover all transportation-related balancing and memorandum account balances for costs that the Commission has authorization to be recovered in rates.

To determine the change in the customer charge components of transportation rates, PG&E will rely on the following:

1) The December 31 forecasted balance for each transportation balancing and memorandum account to be updated in the AGT will be determined based on the most recent recorded balance plus a forecast of the costs and revenues, including interest, through December 31. The exceptions are the GTSRSM balance (see 10.c), which will be determined on a recorded basis as of September 30 of each year during the GT&S term (January 1, 2015 through December 31, 2018): and the TIMPBA balance (see (T) 10.c.), which will not be determined annually, but will be determined in aggregate for the GT&S four-year term ending December 31, 2018.

2) The customer class charge components will be calculated by dividing the balancing account balances as determined in 12.b.1 above by the annual average adjusted BCAP throughput. For four balancing accounts, the balance will first be allocated to the Core and Noncore classes, as described below, then divided by the Core and Noncore annual average adjusted BCAP throughput.

i) TID Almond Power Plant Balancing Account (TIDBA) - - Allocate balance to Core and Noncore classes based on Cold-year January throughput.

ii) Transmission Integrity Management Program Balancing Account (TIMPBA) - - (T) Allocate balance 50% to Core and 50% to Noncore.

iii) Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) - - Allocate balance 50% to Core and 50% to Noncore.

iv) Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) -- Allocate balance 50% to Core and 50% to Noncore.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

12. REVISION DATES (Cont'd.)

c. In-Kind Shrinkage

Pursuant to Decision 03-12-061, an in-kind shrinkage allowance will be applied to all scheduled storage injection volumes beginning April 1, 2004. The in-kind shrinkage quantity will be calculated by dividing the total storage-related GDU and LUAF by the forecast annual storage-cycle quantity.

Decision 03-12-061 authorizes PG&E to update its in-kind shrinkage allowances on an annual basis through an advice letter compliance filing. The in-kind shrinkage allowances for
backbone transmission and distribution will change annually effective November 1. The (N)
storage in-kind shrinkage allowance will change effective April 1. Pursuant to Gas Accord I
D.11-04-031, the core distribution in-kind shrinkage allowance will be seasonal, with separate I
allowances for summer (April-October) and winter (November-March).The in-kind shrinkage I
allowances are shown in Rule 21. (N)

If necessary, PG&E may make separate advice letter filings to adjust in-kind shrinkage allowances at other times of the year in order to better match the actual shrinkage experience on PG&E's system. The BCAP shall continue to be the proceeding in which the pipeline shrinkage calculation methodology, and the proportion of LUAF and GDU that are to be assigned to transmission and distribution shrinkage, is determined.

d. PPP Surcharge Rates

1) **Timing and Frequency:** Per Decision 04-08-010, an advice filing to change core and noncore gas PPP surcharges will be filed by October 31 of each year to be effective January 1 of the next year. The PPP surcharge rates will include a forecast of the December 31 balance for each PPP balancing account, in accordance with prevailing Commission balancing account amortization policies. The forecast will be based on the most recent recorded balance, plus a forecast of the costs and revenues, including interest, through December 31. The forecasted balance for the PPP-RDD account will exclude interest until further direction from the CPUC.

   PG&E may request a change in gas PPP surcharge rates during the year if failure to make the rate change would result in a forecasted total rate increase of 10 percent or more on January 1 of the next year. Requested rate changes will be by advice letter filing and be filed at least 40 days prior to the beginning of the next quarter with an effective date to be determined by the Energy Division in consultation with the California State Board Of Equalization (BOE).

   If the current year program budget for CARE subsidy costs has not been adopted by the CPUC, PG&E will use forecasts of expected CARE subsidy costs based upon estimated future gas prices (using a credible, published source) and CARE penetration rates to calculate the surcharge. Amortization of balances in the applicable PPP balancing accounts will be in accordance with CPUC-established policies for the treatment of these funds.

2) **Information due dates**: By October 31, Energy Division will provide the allocation of RDD, BOE and CPUC administrative costs, and interstate pipeline customer gas volumes used for setting surcharge rates.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

12. REVISION DATES (Cont'd.)

PPP Surcharge Rates (Cont'd.)

3) Refunds: In accordance with PU Code Section 896, certain customers are exempt from Schedule G-PPPS, as follows: (a) all gas consumed by customer's served under Schedules G-EG and G-WSL; (b) all gas consumed by Enhanced Oil Recovery facilities; and (c) all gas consumed by customers in which the State of California is prohibited from taxing under the United States Constitution or the California Constitution, consistent with California Energy Resources Surcharge Regulations 2315 and 2316, as described in Publication No. 11 issued by the California State Board of Equalization. See Schedule G-PPPS for a listing of these exempt customers.

PG&E will annually review its customer accounts to determine if any refunds are warranted. To prevent the issuance of duplicate refunds of PPP surcharge collections, PG&E and BOE will exchange information on customer refunds and PG&E will not issue refunds to customers that have previously received a refund from BOE.

4) Calculation: PPP surcharge rates are calculated in accordance with the formulas and throughput volumes specified in Decision 04-08-010. Additionally, Decision 04-08-010 removes Revenue Fees and Uncollectible (RF&U) expense amounts from PPP (T)
surcharges and excludes PPP surcharge amounts in determining franchise payments by utilities.

13. PIPELINE DEMAND CHARGE CREDITS: When PG&E brokers interstate capacity it will receive conditional credits from interstate pipelines which represent accrued revenues to the interstate pipeline from other parties who have acquired PG&E's brokered capacity. These credits may include other items such as reversed credits previously given to PG&E and late charges assessed per the interstate's FERC-approved tariffs.

(Continued)

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

14. CORE PROCUREMENT INCENTIVE MECHANISM: The Core Procurement Incentive Mechanism (CPIM) is designed to replace traditional reasonableness reviews for Gas Procurement Costs as defined in C.10, above. PG&E will report its procurement activities monthly to the CPUC's Energy Division and Office of Ratepayer Advocates (ORA) and will file an annual report outlining cost savings, rewards or (T) penalties under the CPIM. Incentive rewards and penalties are calculated annually and, upon Commission approval, will be recorded in the Core Sales Subaccount of the Purchased Gas Account (PGA).

Decision 97-08-055 adopted a CPIM mechanism for Post-1997 performance as filed in Application 96-08-043, and as affirmed in D.03-12-061. Modifications adopted in D.04-01-047 are effective for the CPIM year starting November 1, 2002. Modifications adopted in D.07-06-013 are effective for the CPIM year starting November 1, 2007. Modifications adopted in D.10-01-023 are effective for the CPIM year starting November 1, 2010. Modifications adopted in D.08-11-032 and D.11-04-031 are effective for the CPIM year starting November 1, 2011. Modifications adopted in D.16-06-056 are effective for the CPIM (N) year starting November 1, 2016. The CPIM will continue indefinitely until modified or terminated by the (N) CPUC.

The CPIM provides PG&E with a direct financial incentive to procure core gas and transportation services at the lowest reasonable cost by calculating rewards or penalties through comparing actual procurement costs to an aggregate market-based benchmark.

The CPIM establishes both a standard benchmark, which applies to purchasing activities occurring under most operating and temperature conditions, and an alternate benchmark which applies only under extraordinary circumstances requiring economic and/or physical diversions of supplies and transportation resources held by other shippers on the interstate and intrastate transmission system.

The CPIM standard benchmark is made up of three components: (1) the fixed transportation cost component, which includes interstate capacity reservation costs, backbone transmission system capacity reservation costs, and upstream Canadian capacity reservation costs; (2) the variable cost component, which covers commodity costs, 80 percent of winter hedging transaction premiums and settlement net gains and losses in the month of related gas flow, and volumetric transportation costs; and (3) a storage cost component.

The CPIM benchmark components are calculated daily. At the end of each 12-month period, the daily benchmark components are added together to form a single annual benchmark budget. Actual incurred costs are compared to the benchmark. If actual gas costs fall within a range (tolerance band) around the benchmark, costs are deemed reasonable, and are fully recoverable from customers. If actual costs fall below the tolerance band, the savings (the difference between the lower limit of the tolerance band and actual recorded costs) are shared between customers and shareholders according to the following procedure:

a) 80 percent to customers and 20 percent to shareholders per D.07-06-013; and

b) Annual PG&E shareholder awards are capped at 1.5 percent of the total annual gas commodity costs.

Customers and shareholders share equally any costs in excess of the upper limit of the tolerance band.

An alternate benchmark can be invoked by PG&E under certain extraordinary circumstances requiring economic and/or mandatory diversions of gas and transmission resources held by other shippers. All voluntary and involuntary diversion costs are compared to the highest value of the daily PG&E Citygate index range. There is no tolerance band for the alternate benchmark, and actual costs savings or overruns, relative to the benchmark, are shared 95 percent by customers and 5 percent by shareholders.