PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

February 20, 2014

Advice Letter 3447-G

Brian Cherry
Vice President, Regulation and Rates
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177

SUBJECT: ANNUAL GAS TRUE-UP: CONSOLIDATED GAS RATE UPDATE FOR RATES EFFECTIVE JANUARY 1, 2014

Dear Mr. Brian Cherry:

Advice Letter 3447-G is effective as of January 1, 2014.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-7226

December 24, 2013

Advice 3447-G
(Pacific Gas and Electric Company ID U 39 G)

Public Utilities Commission of the State of California

Subject: **Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2014**

Purpose

Pacific Gas and Electric Company ("PG&E") submits for approval by the California Public Utilities Commission ("Commission" or "CPUC") revisions to PG&E's gas tariff schedules effective January 1, 2014.

Consistent with prior years, this AGT advice letter does not include the 2014 gas procurement-related revenue requirement changes, which are being submitted concurrently in PG&E's monthly core procurement advice letter.

Background/Summary

On November 4, 2013, PG&E filed its Annual Gas True-Up ("AGT")[1] Advice Letter 3430-G, requesting approval: (1) to amortize forecast December 31, 2013 gas transportation balancing account balances in rates effective January 1, 2014; and (2) to close two accounts, namely the Winter Gas Savings Program Transportation Subaccount of the Core Fixed Cost Account ("CFCA") and the Sempra and Price Indexing Cases Gas Settlement Refund Memorandum Account. On December 17, 2013, the Energy Division issued a letter approving Advice 3430-G.

This "Annual Gas True-Up: Consolidated Rate Update" advice letter consolidates forecast end-of-year gas balancing account balances with final authorized gas revenue requirement changes previously approved by the CPUC. In order to provide a more accurate forecast, this advice letter updates the forecast balancing account balances that were provided in Advice 3430-G using November 30, 2013 recorded

[1] The AGT is an annual process to update gas transportation balancing accounts as established in PG&E's 2005 Biennial Cost Allocation Proceeding ("BCAP") Decision 05-06-029, p.10 and Finding of Fact 9.

balances as the starting point.[2]

In Advice 3430-G, PG&E provided a preliminary estimate of its 2014 gas transportation revenue requirements, which at the time were estimated to be $2,191 million. In this advice letter, PG&E proposes to recover its final authorized 2014 gas transportation revenue requirements totaling $2,195 million, which is a $172 million increase compared to revenue requirements in present rates. The 2014 gas transportation revenue requirements include end-user transportation costs, gas PPP surcharges (which were submitted for Commission approval in Advice 3426-G), and gas transmission and storage (i.e., Gas Accord V) unbundled costs (See Table 1 below).

Table 1
Proposed Gas Transportation Revenue Requirements
Effective January 1, 2014
(in $ millions)[3]

Description	Currently in Rates	Proposed	Change
End-Use Gas Transportation	$1,647	$1,769	$122
Gas Accord Unbundled Costs	$169	$170	$1
Gas PPP Surcharges	$207	$256	$49
Total Gas Transportation Revenue Requirements	**$2,023**	**$2,195**	**$172**

Attachment 1 and 1A summarize the proposed 2014 gas transportation revenue requirements. Attachment 2 summarizes the gas transportation balancing accounts, which PG&E proposes to amortize in 2014. Attachments 3 through 6 provide rates and surcharges incorporating: (1) amounts previously authorized to be recovered in rates, effective January 1, 2014; and (2) the forecast December 31, 2013 account balances to be amortized in 2014.

Recovery of Transportation Balancing Accounts Already Approved for Amortization in the 2014 AGT

As described in PG&E's Preliminary Statement C-Gas Accounting Terms and Definitions, Part 12.b, Revision Dates, the AGT updates the customer class charge components of transportation rates to recover all gas transportation-related balancing and memorandum account balances for costs that the Commission has authorized to be recovered in rates. PG&E determines the change in the customer class charge components of transportation rates, as follows:

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[2] Advice Letter 3430-G used September 30, 2013 recorded balances as the starting point for December 31, 2013 forecast balancing account balances.

[3] This table does not include the 2014 gas procurement-related revenue requirement changes, which will be submitted concurrently in PG&E's monthly core procurement advice letter.

1) December 31, 2013 balances are forecasted for each gas transportation balancing and memorandum account based on the November 30, 2013[4] recorded balances and a forecast of costs and revenues, including interest, through December 31, 2013; and

2) Customer class charge rate components are calculated by dividing the forecasted December 31, 2013 balancing account balance by PG&E's currently adopted BCAP throughput forecast (D.10-06-035).

Attachment 2 summarizes the forecast December 31, 2013 balances for gas transportation balancing accounts using recorded balances through November 30, 2013. The total December 31, 2013 gas transportation balancing account balances are projected to be undercollected by $175 million, as shown in Attachment 1, line 1, and Attachment 2, line 23. This represents a $53 million increase in the gas transportation balancing account undercollections from those currently amortized in gas transportation rates. Because different balancing accounts are allocated differently to customer classes, the balancing account update results in a $46 million increase in core transportation revenues and a $7 million increase in noncore transportation revenues.

The remainder of this section describes the balancing accounts that will be amortized through this AGT advice letter, effective January 1, 2014.

Certain account balances are recovered in rates through the CFCA and/or Noncore Customer Class Charge Account ("NCA") rate components, as described below. For these accounts, PG&E will transfer the recorded December 31, 2013 balance to the appropriate subaccount of the CFCA and/or NCA, once this advice letter is approved.

Core Fixed Cost Account (CFCA) – (Attachment 2, Lines 1-3)

The CFCA records authorized General Rate Case ("GRC") distribution base revenue amounts (with credits and adjustments), certain other core transportation costs, and transportation revenue from core customers. The CFCA has four subaccounts:

(i) The Distribution Cost subaccount, which recovers the core distribution base revenue requirement adopted in PG&E's GRC, including Annual Attrition Adjustments and the Cost of Capital Proceedings, and other core distribution-related costs authorized by the Commission. The Distribution Cost subaccount is allocated to core customer classes in proportion to their allocation of distribution base revenues;

(ii) The Core Cost subaccount, which recovers non-distribution-related costs, such as the Self-Generation Incentive Program ("SGIP") budget

[4] The PPP surcharge balancing accounts are included in the PPP surcharge proposed in Advice 3426-G. As a result, these PPP surcharge balancing accounts use September 30, 2013 recorded balances as the starting point of their respective December 30, 2103 forecast balances.

and Gas Accord local transmission revenue requirement, adopted by the Commission. The Core Cost subaccount is allocated to core transportation customers on an equal-cents-per-therm basis;

(iii) The Winter Gas Savings Program ("WGSP") Transportation subaccount,[5] which recovers transportation-related WGSP program credits and costs from core customer classes participating in the Program; and

(iv) The AB 32 Cost of Implementation Fee Core subaccount, which recovers the gas cost portion of California Air Resources Board's (ARB) AB 32 Cost of Implementation Fee, allocated to PG&E's core transportation customers.

The AGT includes a forecasted $55.2 million net undercollection in the CFCA, excluding the AB 32 Cost of Implementation Fee Core subaccount, which is described separately below. The net undercollection in the CFCA results from:

(i) A forecasted $45.0 million undercollection in the Distribution Cost subaccount;

(ii) A forecasted $4.7 million undercollection in the Core Cost subaccount; and

(iii) A forecasted $5.5 million undercollection in the WGSP Transportation subaccount.

Noncore Customer Class Charge Account (NCA) – (Attachment 2, Lines 4-5)

The NCA records noncore costs and revenues from noncore customers for balancing account protected items such as SGIP. The NCA has three subaccounts:

(i) The Noncore subaccount, which recovers costs and balances from all noncore customers for non-distribution cost-related items and is allocated on an equal-cents-per-therm basis;

(ii) The Distribution subaccount, which recovers the noncore distribution portion of gas revenue requirements adopted in GRC decisions and other noncore distribution related costs and balances approved by the Commission. It is allocated to noncore classes in proportion to their allocation of distribution base revenues; and

[5] Advice 3430-G requested permission to close the Winter Gas Savings Program Subaccount and transfer the balance as of December 31, 2013 to the CFCA. On December 17, 2013, the CPUC issued a letter approving Advice 3430-G.

(iii) The AB 32 Cost of Implementation Fee Noncore subaccount, which recovers the gas cost portion of the AB 32 cost of implementation fee, allocated to PG&E's noncore transportation customers.

The AGT includes a forecasted $4.2 million net overcollection in the NCA, excluding the AB 32 Cost of Implementation Fee Noncore subaccount, which is described separately below. The net overcollection in the NCA results from:

(i) A forecasted $3.2 million overcollection in the Noncore subaccount; and

(ii) A forecasted $1.0 million overcollection in the Distribution subaccount.

AB 32 Cost of Implementation Fee – (Attachment 2, Line 15)

As described above, the AB 32 Cost of Implementation (COI) Fee consists of two subaccounts: (1) the core subaccount of the CFCA recovers the gas cost portion of the AB 32 COI Fee allocated to core customers; and (2) the noncore subaccount of the NCA recovers the gas cost portion of the AB 32 COI Fee allocated to noncore customers. In accordance with D.12-10-044 and Advice 3348-G, the AB 32 COI Fee is allocated to all non-exempt customers on an equal-cents-per-therm basis. As indicated in Advice Letter 3348-G, the ARB provides PG&E with an invoice and a list of PG&E customers who pay the COI fee directly to the ARB. These customers paying the COI fee directly to the ARB are exempt from paying for COI fee costs through PG&E's rates. PG&E has updated the volumes used to calculate PG&E's 2014 COI rates to reflect a reduction of the volumes associated with exempt customers. The AGT balance amortized in 2014 rates consists of a forecasted $5.0 million net undercollection in the AB 32 Cost of Implementation Fee subaccounts. This balance is the sum of COI invoice costs received from the ARB recorded during 2013 plus a small forecast undercollection of the adopted COI costs included in 2013 rates.

Core Brokerage Fee Balancing Account (CBFBA) – (Attachment 2, Line 6)

The CBFBA ensures that variations between the adopted forecast brokerage fee revenue requirement credits in core transportation rates and actual brokerage fee revenues collected from core procurement customers will flow through core transportation rates. This account was adopted in PG&E's 2005 BCAP decision (D.05-06-029). The AGT includes a forecasted $0.7 million undercollection in the CBFBA. The CBFBA balance is included in the rate component of the Core Cost subaccount of the CFCA.

Hazardous Substance Mechanism (HSM) – (Attachment 2, Line 7)

The HSM provides a uniform methodology for allocating costs and related recoveries associated with covered hazardous substance-related activities, including hazardous substance clean-up and litigation, and related insurance recoveries, as set forth in D.94-05-020 (the original HSM decision) through the

Hazardous Substance Cost Recovery Account ("HSCRA"). This AGT forecasts a $51.8 million undercollection in the HSCRA. Once allocated, the HSCRA balance is included in the rate component of the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA.

Balancing Charge Account (BCA) – (Attachment 2, Line 8)

The BCA records the revenue and costs associated with providing gas balancing service, including charges and credits, as described in gas Schedule G-BAL and Gas Rule 14. PG&E currently forecasts a $25,000 overcollection in the BCA as of December 31, 2013.

Affiliate Transfer Fees Account (ATFA) – (Attachment 2, Line 9)

The ATFA records employee transfer fees paid to PG&E by its holding company, PG&E Corporation, and affiliates for future ratemaking treatment to ensure that PG&E's customers receive the fees, pursuant to the decision which approved for PG&E to become a wholly owned subsidiary of a holding company (D.96-11-017). This AGT forecasts a $0 balance in the ATFA, which represents activity in the account for 2013. The ATFA balance is included in the rate component of the Distribution Cost subaccount of the CFCA and the Distribution subaccount of the NCA.

Customer Energy Efficiency Incentive Account (CEEIA) – (Attachment 2, Line 10)

The CEEIA records the gas portion of any Energy Efficiency Risk Reward Incentive Mechanism ("RRIM") award or penalty that is authorized by the Commission to be recovered in rates. The forecast year-end balance incorporates the residual 2013 balance in the account and the gas portion of the 2011 RRIM claim as authorized by the CPUC in Resolution G-3491. Interest does not accrue in this subaccount pursuant to D.07-09-043. This AGT includes a forecasted $4.0 million undercollected balance, which will be recovered through the CEE Incentive rate component.

SmartMeter™ Project Balancing Account-Gas (SBA-G) – (Attachment 2, Line 11)

The SBA-G recovers the incremental Operating and Maintenance ("O&M") and Administrative and General ("A&G") expenditures, capital-related costs, capital-related revenue requirements, benefits, and revenues associated with the SmartMeter™ Project, as authorized in D.06-07-027. This AGT includes a forecasted $15.9 million undercollected balance in the SBA-G. The SBA-G is recovered through the SmartMeter™ Project rate component.

California Solar Initiative Thermal Program Memorandum Account (CSITPMA) – (Attachment 2, Line 12)

Advice 3093-G established the CSITPMA to record expenses incurred by PG&E for implementing the CSI Thermal Program authorized by D.10-01-022. Customers who participate in the California Alternate Rates for Energy ("CARE") or Family Electric Rate Assistance ("FERA") Programs and customers who are currently exempt from funding the Self-Generation Incentive Program and customers exempt pursuant to Public Utilities Code Section 2863(b)(4) are exempt from CSI Thermal Program charges. This AGT includes a forecasted $4.6 million undercollected balance in the CSITPMA as of December 31, 2013 and will be recovered in the CSITPMA rate component.

Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) – (Attachment 2, Line 13)

The AMCDOP records the difference in the revenue requirement associated with the costs determined in other proceedings and the revenue requirement based on placeholder costs included in the Gas Accord V Settlement Agreement as adopted in D.11-04-031. The AMCDOP consists of the following five subaccounts:

(i) The Administrative and General ("A&G") Subaccount, which tracks the amount of A&G expenses allocated to Gas Transmission & Storage ("GT&S") in the GRC against the allocation of A&G to GT&S services in the Gas Accord V Settlement Agreement;

(ii) The Uncollectibles Subaccount, which tracks the amount of uncollectibles expense based on the uncollectibles factor determined in the GRC against the uncollectible costs included in the Gas Accord V Settlement Agreement;

(iii) The Pension Subaccount, which tracks the amount of pension costs allocated to GT&S in the Pension Recovery proceeding against the pension costs allocated to GT&S services in the Gas Accord V Settlement Agreement;

(iv) The Cost of Capital Subaccount, which tracks the authorized cost of capital as determined in PG&E's cost of capital proceeding against the cost of capital used to set GT&S cost of service revenue requirements in the Gas Accord V Settlement Agreement; and

(v) The Other GRC Costs Subaccount, which tracks the amount of costs and policies determined to be allocated and applied to GT&S in the GRC (not already reflected in the preceding A&G and Uncollectibles subaccounts) against the allocation of costs and policies allocated and applied to GT&S services in the Gas Accord V Settlement Agreement.

The AGT includes a forecasted net $0 balance in the AMCDOP. The AMCDOP is included in the rate component of the Core Cost subaccount of the CFCA and Noncore subaccount of the NCA. As further described in the "Gas Transmission and Storage Rates" section below, Attachment 6 contains the complete set of Gas Accord V rate tables.

Non-Tariffed Products and Services Balancing Account (NTBA-G) – (Attachment 2, Line 14)

The NTBA-G is used to record the customer share of revenues net of costs and income taxes associated with new Non-Tariffed Products and Services ("NTP&S"), pursuant to CPUC Affiliate Transaction Rule VII. Costs and revenues are tracked for appropriate disbursement of revenues, net of expense, to customers and shareholders via the 50/50 sharing mechanism as approved by D.99-04-021. The NTBA-G does not apply to NTP&S in PG&E's existing NTP&S catalogue, which remains subject to Other Operating Revenue treatment, consistent with D.99-04-021. In Resolution G-3417, the Commission approved PG&E's proposal to offer the Mover Services Program; to recover costs and disburse net revenues through the NTBA-G; to transfer the balance at the end of the year from the NTBA-G to the CFCA; and to include it in the AGT filing, in order to credit customer revenues pursuant to D.99.04-021. If the balance at the end of the year for any product or service category is undercollected, no transfer will be made for that product or service category, and the balance for that product or service category will be reset to zero at the beginning of the year. PG&E forecasts a $0.2 million overcollected balance for this account, as of December 31, 2013; which will be transferred to the Distribution Cost subaccount of the CFCA.

Gas Pipeline Expense and Capital Balancing Account (GPECBA) – (Attachment 2, Line 16)

The GPECBA tracks the aggregate revenue requirements associated with the expense and capital costs of PG&E's Pipeline Safety Enhancement Plan, as authorized by the Commission in D.12-12-030, and any other subsequent Commission decisions. The GPECBA records the difference between adopted forecast revenue requirements and capital and expense revenue requirements based on actual costs for the Plan through 2014. The GPECBA has two subaccounts:

(i) The CPUC Reimbursement Subaccount, which records PG&E's reimbursements to the Commission associated with implementing and complying with D.12-12-030, up to $15 million. This AGT includes a forecasted $0 balance in the CPUC Reimbursement Subaccount as of December 31, 2013.

(ii) The Program Expense and Capital Subaccount, which records the revenue requirements associated with the actual expense and capital cost PG&E incurred to implement the programs authorized in

D.12-12-030. The 2012-2014 revenue requirement recorded in this subaccount is capped at $299.2 million or $295.4 million (without FF&U). Disposition of the balance in this subaccount shall be determined in the AGT at the end of 2014 (for rates effective January 1, 2015). As a result, this subaccount is not included in the forecasted balance for the GPECBA in this AGT advice letter.

Gas Meter Reading Costs Balancing Account (MRCBA-G) – Attachment 2, Line 17)

The MRCBA-G records and recovers gas meter reading costs, including Energy Delivery Services meter reading costs and severance costs, up to an annual combined electric and gas balancing accounts cap of $76.2 million, pursuant to D.11-05-018 in PG&E's 2011 GRC. The MRCBA-G is recovered through the Distribution Cost subaccount of the CFCA. This AGT includes a forecasted $26.8 million undercollected balance in the MRCBA-G as of December 31, 2013. The 2014 Annual Electric True-Up ("AET") Advice 4278-E-B, which is expected to be filed December 31, 2013, will include a $33.0 million forecast for December 31, 2013, for the MRCBA-E, for a combined total of $59.8 million, which is under the $76.2 million cap.

Gas Operational Cost Balancing Account (GOBA) – (Attachment 2, Line 18)

The GOBA records the difference between PG&E's authorized and actual cost associated with the cost of electricity used to provide gas transmission and storage services to its customers and Greenhouse Gas (GHG) cost associated with PG&E's gas compressor stations. The GOBA has two subaccounts:

(i) The Electricity Cost Subaccount, which records the difference between the cost of electricity used to provide gas transmission and storage services adopted in PG&E's Gas Accord V Settlement Agreement, and PG&E's recorded cost of electricity used to provide gas transmission and storage services; and

(ii) The Compressor Station Greenhouse Gas (GHG) Cost subaccount, which records the difference between the Commission's forecast and PG&E's actual GHG costs associated with its gas compressor stations, as authorized in D.13-03-017.

This AGT includes a forecasted $9.9 million net undercollection in the GOBA. The GOBA is recovered through the Core Cost subaccount of the CFCA and Noncore subaccount of the NCA.

Pension Contribution Balancing Account (PCBA) – (Attachment 2, Line 19)

The PCBA includes the revenue requirement associated with the difference, if any, between adopted pension contributions and (i) lower contributions for any reason; or (ii) federally mandated higher contributions, with the difference to be refunded to or recovered from customers. PG&E's contribution to the pension plan have matched the amounts adopted in D.06-06-014 and D.07-03-044. As a result, PG&E does not expect that the PCBA will have a balance on December 31, 2013.

TID Almond Power Plant Balancing Account (TIDBA) – (Attachment 2, Line 20)

The purpose of the TIDBA is to record the difference in revenue requirement based on the amount credited to rate base per the adopted Gas Accord V Settlement Agreement and the actual amount. The TIDBA balance is included in the rate component of the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA. This AGT includes a forecasted $1.3 million overcollected balance in the TIDBA. In accordance with the Gas Accord V Settlement Agreement (Section 7.2.10), this balance is allocated to customers through the Customer Class Charge in the AGT.

Revised Customer Energy Statement Balancing Account (RCESBA-G) – (Attachment 2, Line 21)

The RCESBA-G (Gas Preliminary Statement Part CV) tracks and records actual gas revenue requirements associated with authorized costs incurred to implement the Revised Customer Energy Statement Project, pursuant to D.12-03-015. Advice 3287-G filed in compliance with D.12-03-015 provided that the disposition of the balance in the account shall be through the AGT via the CFCA and the NCA, or through another proceeding as authorized by the Commission. The final disposition of this account shall be through PG&E's 2014 GRC proceeding. This AGT includes a forecasted $4.4 million overcollected balance in the RCESBA as of December 31, 2013.

Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) – (Attachment 2, Line 22)

The GTSRSM records the difference between the customer portion of recorded total revenue over- or under-collections (derived for backbone, local transmission and storage service) and the $30.0 million seed value embedded in rates as adopted in PG&E's Gas Accord V Settlement Agreement. The over- or under-collections are determined by comparing revenue from implemented Gas Accord V rates with the revenue requirement used to determine those rates. The difference between the adopted revenue requirement in D.11-04-031 and the adjusted Gas Accord revenue requirement post-GRC and Pension decisions is tracked in the AMCDOP as discussed above. The GTSRSM consists of the following four subaccounts:

(i) The Backbone Subaccount, which records the difference between the adopted backbone revenue requirement (including the portion of the Local Transmission Bill Credits recovered through the surcharge on backbone rates) and recorded backbone revenues, whether an over-collection or an under-collection, to be shared 50 percent to customers and 50 percent to shareholders.

(ii) The Local Transmission Subaccount, which records the difference between the adopted local transmission revenue requirement (excluding the Local Transmission Bill Credits) and recorded local transmission revenues, whether an over-collection or an under-collection, to be shared 75 percent to customers and 25 percent to shareholders.

(iii) The Storage Subaccount, which records the difference between the adopted storage revenue requirement and recorded storage revenues, if an over-collection, to be shared 75 percent to customers and 25 percent to shareholders. PG&E is at risk for 100 percent of any net undercollections.

(iv) The Revenue Sharing Subaccount, which records the difference between the customer portion of recorded total over- or under-collections, as determined in the above three subaccounts, and the $30.0 million seed value embedded in rates.

In accordance with Preliminary Statement Part CP, the balances in the first three subaccounts[6] are transferred to the Revenue Sharing Subaccount as of September 30 of each year; and the Revenue Sharing Subaccount is transferred to the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA. This advice letter includes a forecasted $11.0 million undercollected balance in the GTSRSM.

<u>Closure of Transportation Balancing Accounts</u>

Winter Gas Savings Program Subaccount of CFCA

On October 3, 2013, PG&E submitted advice letter 3422-G to retire its Winter Gas Savings Program gas schedule tariff (G-WGSP). As PG&E had previously indicated to the Energy Division, the 2013 program year was the final year of the WGSP. As a result, in Advice 3430-G, PG&E requested permission to close the WGSP subaccount of the CFCA and transfer the remaining balance as of December 31, 2013 to the CFCA's Distribution Subaccount.[7] On December 17, 2013, the Energy Division approved Advice 3430-G. The January 1, 2014 CFCA-Distribution subcomponent rates will include the impacts of trueing up recorded 2013 WGS

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[6] If the storage subaccount is undercollected as of September 30, the balance will be transferred to earnings.

[7] PG&E also requested permission in Advice 3430-G to close the December 31, 2013 WGSP Procurement subaccount of the Purchased Gas Account ("PGA") to the Core Sales subaccount of the PGA. PG&E's monthly pricing filing for gas procurement rates effective January 1, 2014 will include the PGA-WGSP true up for 2013 bill credits versus 2013 revenues by class.

Program bill credits by customer class with 2013 WGS Program revenues by customer class.

Sempra and Price Indexing Cases Gas Settlement Refund Memorandum Account (SPGSRMA)

The SPGSRMA recorded the proportional share of the Sempra and Price Indexing Cases Gas Settlements considerations attributable to core aggregation customers, as authorized in D.10-01-024. On July 25, 2011, PG&E submitted its status report to the CPUC, stating all refunds had been returned to customers, completing the final compliance item required related to the refunds. On August 29, 2011, the law firm representing core gas customers in the Sempra and Price Indexing Cases filed a Petition to Modify (PTM) D.10-01-024, claiming that proceeds from the Price Indexing Settlement had been erroneously allocated to the core customer class instead of the non-core customer classes. As a result of this PTM, PG&E maintained the SPGSRMA until this final issue was resolved. In October 2012, pursuant to D.12-09-032, PG&E made a final payment to the Class Settlement Administrator, and the Rulemaking was closed. PG&E requested permission to close this account in Advice 3430-G. On December 17, 2013, the Energy Division issued a letter approving Advice 3430-G.

Discussion of Recent, Pending and Anticipated CPUC Proceedings and Advice Letters

The following section highlights recent and pending decisions and advice letter filings that impact PG&E's gas transportation revenue requirements and rates filed in the AGT:

2014 General Rate Case – (Attachment 1, Lines 2, 7)

The Commission has not issued a final decision on PG&E's 2014 General Rate Case (GRC) Phase 1 Application, A.12-11-009. As a result, the GRC gas distribution and SmartMeter™ revenue requirements of this advice letter reflect the 2013 authorized revenue requirements, consistent with the 2013 AGT Advice 3353-G.[8]

Mobile Home Park – (Attachment 1, Line 4)

The Commission did not issue a final decision on PG&E's 2014 master-metered mobile home park (MHP) conversion program estimated revenue requirement by December 19, 2013. As a result, the revenue requirement and resulting rates are not included in this AGT Consolidated Gas Update advice letter.

[8] This treatment is also consistent with the December 19, 2013 Resolution approving PG&E's 2014 Annual Electric True-Up Advice Letter. Resolution E-4620 allowed PG&E to hold electric distribution and SmartMeter revenue requirements at their 2013 levels until the Commission issues a decision on A.12-11-009.

SmartMeter™ Opt-Out – (Attachment 1, Line 5)

The Commission did not issue a final decision on PG&E's application (A.11-03-014) to recover its incremental capital and operating expenses needed to implement its SmartMeter™ Opt-Out Program for residential customers by December 19, 2013. As a result, the revenue requirement and resulting rates are not included in this AGT Consolidated Gas Update advice letter.

Energy Efficiency Risk Reward Incentive Mechanism (RRIM) – (Attachment 2, Line 10)

Decision 12-12-032 adopted a new incentive mechanism applicable to the 2010-2012 Energy Efficiency Program cycle. On September 30, 2013, PG&E filed Advice 3419-G requesting earnings for 2011 to be approved before the end of the year. On December 5, 2013, the CPUC issued Resolution G-3491, which authorized PG&E's total requested award of $21.6 million, with the gas portion of $3.9 million based on PG&E's net benefit split of 82 percent electric and 18 percent gas as approved in Advice 3356-G-A/4176-E-A. PG&E has recorded the amount in the Customer Energy Efficiency Balancing Account for rate recovery effective January 1, 2014.

Pipeline Safety Enhancement Plan – (Attachment 1, Lines 21-24)

On December 28, 2012, the CPUC issued D. 12-12-030, approving PG&E's Pipeline Modernization scope of work and ordering PG&E to file an application after the completion of its Maximum Allowable Operating Pressure (MAOP) Validation Project and records search to present the results of those efforts, and update its authorized revenue requirements and related budgets. Accordingly, on October 29, 2013, PG&E filed its Pipeline Safety Enhancement Program (PSEP) Update application. Due to records found and other information learned during MAOP Validation, PG&E proposes a reduction in the breadth of its strength testing and pipe replacement programs. The Commission has not issued a final decision on this PSEP Update application. As a result, the revenue requirements in Attachment 1 reflect the 2014 PSEP revenue requirement of $181 million as authorized in D.12-12-030 and confirmed by the Energy Division's December 17, 2013 approval letter of Advice 3430-G.

<u>Gas Public Purpose Program Authorized Funding</u>

This AGT incorporates gas PPP surcharge changes that were filed in Advice Letter 3426-G on October 31, 2013. The gas PPP surcharge rate impacts on customers are shown in Attachment 1.

PU Code Sections 890-900 and D.04-08-010 authorize a gas surcharge rate to fund public purpose programs. The gas PPP Surcharge advice letter updates the natural gas PPP surcharge rates to fund authorized energy efficiency ("EE"), Energy Savings

Assistance (“ESA”) (formerly low income energy efficiency), CARE and public-interest research, development and demonstration (“RD&D”) programs.

The gas PPP surcharges proposed include:

1) Total gas PPP authorized program funding of $156.2 million for EE, ESA, CARE administrative expenses, RD&D, Board of Equalization and Statewide Marketing Education & Outreach administrative costs. This represents a $21.2 million increase from 2013;

2) Amortization over 12 months of forecasted December 31, 2013 balances in the PPP surcharge balancing accounts totaling a $9.3 million overcollection; and

3) A projected 2013 CARE revenue shortfall of $108.9 million, which represents a $3.5 million decrease from the forecasted 2013 CARE customer discount. This shortfall is included in the PPP-CARE portion of the gas PPP surcharge rates for 2014 and accounted for as a reduction of net transportation revenue requirement in rates for a zero-sum impact on the total gas revenue requirement.

Gas Transmission and Storage Rates

Revenue Requirement Adjustment

The Commission adopted the Gas Accord V Settlement in D.11-04-031, dated April 14, 2011. The following table shows resulting total annual 2014 revenue requirement changes.

Annual Gas Transmission and Storage Revenue Requirements
2014
($000)

GT&S 2014 Revenue Requirement (Filed in AL 3374-G)	$556,557
Less: 2014 Local Transmission line 304 Project	($539)
Less: 2014 Local Transmission Line 407 Phase 1 project	($6,576)
Less: 2014 Local Transmission Line 407 Phase 2 project	($6,484)
Less: 2014 Backbone P02158-Topock K-Units Replacement-Ph1 Project	($7,525)
Less: 2014 Backbone Delevan K3/Gerber – Line 400 project	($493)
Less: 2014 Backbone Delevan K3/Gerber – Line 401 project	($518)
2014 GT&S Revenue Requirements (excluding non-operational projects)	$534,421

Attachment 6 provides an update of the GT&S revenue requirements and rates tables, included in Appendix A of the Gas Accord V Settlement. This Attachment is unchanged from that filed in Advice 3430-G, the Annual Gas True-Up of Gas Transportation Balancing Accounts, which was filed on November 4, 2013.

Backbone and Local Transmission Adder Project Rate Adjustments

Section 7.4 of the Gas Accord V Settlement addresses treatment of costs associated with various Backbone and Local Transmission adder projects. Under the terms of the Settlement, adder project costs are to be included in rates only if the project is actually built and only starting on January 1 following the project's in-service date. Three Local Transmission adder projects, Line 304, Line 407 Phase 1, and Line 407 Phase 2, were scheduled to be, but were not, operational in 2013. As shown above, Local Transmission rates effective January 1, 2014 have been adjusted to remove recovery of the Line 304, Line 407 Phase 1, and Line 407 Phase 2 adder project revenue requirements.

Three Backbone Transmission adder project, P02158-Topock K-Units Replacement Phase 1, Delevan K3/Gerber – Line 400, and Delevan K3/Gerber – Line 401 were scheduled to be, but were not, operational in 2013. Accordingly, as shown above, Backbone Transmission rates effective January 1, 2014 have been adjusted to remove recovery of the P02158-Topock K-Units Replacement Phase 1, Delevan K3/Gerber – Line 400, and Delevan K3/Gerber – Line 401 adder project revenue requirements.

<u>Effective Date</u>

PG&E requests that this Tier 1 filing be approved effective January 1, 2014.

Changes to core gas transportation rates will be incorporated into the monthly core procurement advice filing for rates effective January 1, 2014.

<u>Protests</u>

Anyone wishing to protest this advice letter may do so by sending a letter by January 13, 2014, which is 20 days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via e-mail or U.S. Mail (and by facsimile if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter. (General Order 96-B, Rule 7.4.) The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Rule 3.11).

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list, and the service lists below. Address changes to the General Order 96-B service and all electronic approvals should be directed to PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Advice letter filings can also be accessed electronically at http://www.pge.com/tariffs.

Brian Cherry /IG

Vice President – Regulatory Relations

cc: 2009 Biennial Cost Allocation Proceeding (BCAP) (A.09-05-026)
Gas PPP Surcharge (R.02-10-001)
2011 Gas Transmission and Storage Proceeding (A.09-09-013)
Eugene Cadenasso, Energy Division
Richard Myers, Energy Division

Attachments

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 G)**

Utility type:	Contact Person: Igor Grinberg
☐ ELC ☑ GAS	Phone #: 415-973-8580
☐ PLC ☐ HEAT ☐ WATER	E-mail: ixg8@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **3447-G** **Tier: 1**

Subject of AL: **Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2014**

Keywords (choose from CPUC listing): Transportation Rates, Balancing Accounts, Non-Core, Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☑ Annual ☐ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.05-06-029

Does AL replace a withdrawn or rejected AL? No. If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Is AL requesting confidential treatment? No.

If so, what information is the utility seeking confidential treatment for: N/A

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: N/A

Resolution Required? ☐ Yes ☑No

Requested effective date: **January 1, 2014** No. of tariff sheets: 37

Estimated system annual revenue effect (%): $2,195 million

Estimated system average rate effect (%): see advice letter

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: G-NT, G-EG, G-WSL, G-NGV4, G-AA, G-AAOFF, G-AFT, G-AFTOFF, G-BAL G-CFS, G-LEND, G-LNG, G-NAS, G-NFS, G-PARK, G-SFS, G-SFT, G-XF, Gas Preliminary Statements Part B, Part C

Service affected and changes proposed: Rate value changes per the advice letter and attachments, and minor text updates.

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

ATTACHMENT 1

PACIFIC GAS AND ELECTRIC COMPANY
2014 ANNUAL GAS TRUE-UP (AGT)
2014 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING
($ THOUSANDS)

Line No.		A Present in Rates as of 4/1/13	B Proposed as of 1/1/2014	C Total Change	D Core	E Noncore / Unbundled	Line No.
	END-USE GAS TRANSPORTATION						
1	Gas Transportation Balancing Accounts	121,520	174,813	53,293	45,890	7,403	1
2	GRC Distribution Base Revenues (includes distribution portion of Cost of Capital) [1, 2]	1,172,719	1,172,719	-	(17)	17	2
3	Pension	52,691	46,015	(6,676)	(6,444)	(232)	3
4	Mobile Home Park	-	-	-	-	-	4
5	SmartMeter™ Opt-Out	-	-	-	-	-	5
6	Self Generation Incentive Program Revenue Requirement	5,760	6,480	720	285	435	6
7	SmartMeter™ Project [1]	79,202	79,202	-	-	-	7
8	CPUC Fee	3,210	3,210	-	-	-	8
9	Core Brokerage Fee Credit	(6,583)	(6,583)	-	-	-	9
10	Winter Gas Savings Program - Transportation	2,474	-	(2,474)	(2,474)	-	10
11	Less CARE discount recovered in PPP surcharge from non-CARE customers	(112,382)	(108,850)	3,532	3,532	-	11
12	FF&U	2,764	3,435	671	569	102	12
13	Total Transportation RRQ with Adjustments and Credits	1,321,375	1,370,441	49,066	41,341	7,725	13
14	Procurement-Related G-10 Total	(1,025)	(1,042)	(17)	(17)	-	14
15	Procurement-Related G-10 Total Allocated	1,025	1,042	17	6	11	15
16	Total Transportation Revenue Requirements Reallocated	1,321,375	1,370,441	49,066	41,330	7,736	16
	Gas Accord Transportation Revenue Requirements						
17	Local Transmission	205,643	212,200	6,557	2,486	4,071	17
18	Customer Access	4,860	5,026	166	-	166	18
19	Total Gas Accord Transportation RRQ	210,503	217,226	6,723	2,486	4,237	19
20	Implementation Plan Revenue Requirements						20
21	Implementation Plan - Local Transmission	91,312	134,616	43,304	26,872	16,432	21
22	Implementation Plan - Backbone	22,415	40,770	18,355	7,920	10,435	22
23	Implementation Plan - Storage	1,616	5,572	3,956	2,342	1,614	23
24	Total Implementation Plan	115,343	180,958	65,615	37,134	28,481	24
25	**Total End Use Gas Transportation RRQ**	**1,647,221**	**1,768,625**	**121,404**	**80,950**	**40,454**	25
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING						
26	Energy Efficiency	56,178	74,077	17,899	16,107	1,792	26
27	Energy Savings Assistance	65,208	67,982	2,774	2,496	278	27
28	Research and Development and BOE Administrative Fees	10,882	11,079	197	139	58	28
29	CARE Administrative Expense	2,739	2,806	67	52	15	29
30	Statewide Marketing, Education & Outreach - EE Flex Alert	-	255	255	229	26	30
31	Total Authorized PPP Funding	135,007	156,199	21,192	19,023	2,169	31
32	PPP Surcharge Balancing Accounts	(40,827)	(9,295)	31,532	25,351	6,181	32
33	CARE discount recovered from non-CARE customers	112,382	108,850	(3,532)	(1,610)	(1,922)	33
34	**Total PPP Required Funding**	**206,562**	**255,754**	**49,192**	**42,764**	**6,428**	34
	GAS ACCORD UNBUNDLED COSTS						
35	Backbone Transmission	134,765	135,405	640	-	640	35
36	Storage	34,615	34,980	365	-	365	36
37	**Total Gas Accord Unbundled**	**169,380**	**170,385**	**1,005**	**-**	**1,005**	37
38	**TOTAL REVENUE REQUIREMENTS**	**2,023,163**	**2,194,764**	**171,601**	**123,714**	**47,887**	38

1. The CPUC has not issued a final decision for the 2014 GRC before the end of 2013. As a result, January 1 revenue requirements for GRC Distribution and SmartMeter are kept at the same level as the 2013 AGT amounts as a placeholder.
2. Since the 2013 AGT AL, the allocation between core and noncore has changed slightly due to the update of the average A-10 electric rate which impacts the NGV2 Compressor cost.

Notes:
A positive balance represents an under-collection. A negative balance represents an over-collection.

ATTACHMENT 1A

PACIFIC GAS AND ELECTRIC COMPANY
2014 ANNUAL GAS TRUE-UP (AGT)

2014 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS,
AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING ALLOCATION TO CORE/NONCORE/UNBUNDLED
($ THOUSANDS)

Line No.		Proposed as of 1/1/2014	Core	Noncore / Unbundled	Line No.
	END-USE GAS TRANSPORTATION				
1	Gas Transportation Balancing Accounts	174,813	132,406	42,407	1
2	GRC Distribution Base Revenues	1,172,719	1,131,944	40,775	2
3	Pension	46,015	44,415	1,600	3
4	Mobile Home Park	-	-	-	4
5	SmartMeter™ Opt-Out	-	-	-	5
6	Self Generation Incentive Program Revenue Requirement	6,480	2,569	3,911	6
7	SmartMeter™ Project	79,202	79,202	-	7
8	CPUC Fee	3,210	1,970	1,240	8
9	Core Brokerage Fee Credit	(6,583)	(6,583)	-	9
10	Winter Gas Savings Program - Transportation	-	-	-	10
11	Less CARE discount recovered in PPP surcharge from non-CARE customers	(108,850)	(108,850)	-	11
12	FF&U	3,435	2,808	627	12
13	Total Transportation RRQ with Adjustments and Credits	1,370,441	1,279,881	90,560	13
14	Procurement-Related G-10 Total	(1,042)	(1,042)	-	14
15	Procurement-Related G-10 Total Allocated	1,042	411	631	15
16	Total Transportation Revenue Requirements Reallocated	1,370,441	1,279,250	91,191	16
	Gas Accord Transportation Revenue Requirements				
17	Local Transmission	212,200	135,339	76,861	17
18	Customer Access	5,026	-	5,026	18
19	Total Gas Accord Transportation RRQ	217,226	135,339	81,887	19
20	Implementation Plan Revenue Requirements				20
21	Implementation Plan - Local Transmission	134,616	85,881	48,735	21
22	Implementation Plan - Backbone	40,770	17,462	23,308	22
23	Implementation Plan - Storage	5,572	3,291	2,281	23
24	Total Implementation Plan	180,958	106,634	74,324	24
25	**Total End Use Gas Transportation RRQ**	**1,768,625**	**1,521,223**	**247,402**	25
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING				
26	Energy Efficiency	74,077	66,657	7,420	26
27	Energy Savings Assistance	67,982	61,173	6,809	27
28	Research and Development and BOE Administrative Fees	11,079	7,088	3,991	28
29	CARE Administrative Expense	2,806	1,678	1,128	29
30	Statewide Marketing, Education & Outreach - EE Flex Alert	255	229	26	30
31	Total Authorized PPP Funding	156,199	136,825	19,374	31
32	PPP Surcharge Balancing Accounts	(9,295)	(2,706)	(6,589)	32
33	CARE discount recovered from non-CARE customers	108,850	65,072	43,778	33
34	**Total PPP Required Funding**	**255,754**	**199,191**	**56,563**	34
	GAS ACCORD UNBUNDLED COSTS				
35	Backbone Transmission	135,405	-	135,405	35
36	Storage	34,980	-	34,980	36
37	**Total Gas Accord Unbundled**	**170,385**	**-**	**170,385**	37
38	**TOTAL REVENUE REQUIREMENTS**	**2,194,764**	**1,720,414**	**474,350**	38

Notes:
A positive balance represents an under-collection. A negative balance represents an over-collection.

ATTACHMENT 2

PACIFIC GAS AND ELECTRIC COMPANY
2014 ANNUAL GAS TRUE-UP (AGT)
BALANCING ACCOUNT FORECAST SUMMARY

($ THOUSANDS)

Line No.		Balance: Nov. 2013 Recorded Dec. 2013 Forecast	Allocation: Core	Allocation: Noncore	Balance: December 2012 Recorded (1)	Allocation: Core	Allocation: Noncore	Line No.
		A	B	C	D	E	F	
	GAS TRANSPORTATION BALANCING ACCOUNTS							
1	Core Fixed Cost Account (CFCA) - Distribution Cost Subaccount	$44,994	$44,994	$0	$49,774	$49,774	$0	1
2	CFCA - Core Cost Subaccount	$4,729	$4,729	$0	($3,797)	($3,797)	$0	2
3	CFCA - Winter Gas Savings Subaccount - Transportation	$5,490	$5,490	$0	($1,870)	($1,870)	$0	3
4	Noncore Customer Class Charge Account (NCA) - Noncore Subaccount	($3,175)	$0	($3,175)	($5,932)	$0	($5,932)	4
5	NCA - Distribution Subaccount	($1,007) (2)	$0	($1,007)	($922)	$0	($922)	5
6	Core Brokerage Fee Balancing Account	$736	$736	$0	$642	$642	$0	6
7	Hazardous Substance Mechanism	$51,776	$20,419	$31,357	$39,094	$15,418	$23,676	7
8	Balancing Charge Account	($25)	($10)	($15)	$730	$288	$442	8
9	Affiliate Transfer Fee Account	$0	$0	$0	($29)	($28)	($1)	9
10	Customer Energy Efficiency Incentive Recovery Account - Gas	$3,982	$3,947	$35	$3,849	$3,815	$34	10
11	SmartMeter™ Project Balancing Account	$15,929	$15,929	$0	$18,047	$18,047	$0	11
12	California Solar Initiative Thermal Program Memoradum Account	$4,598	$2,696	$1,902	$6,239	$2,461	$3,778	12
13	Adjustment Mechanism of Costs Determined in Other Proceedings	$0	$0	$0	$0	$0	$0	13
14	Non-Tariffed Products and Services Balancing Account	($209)	($209)	$0	($365)	($365)	$0	14
15	AB 32 Cost of Implementation Fee	$4,960 (3)	$2,544	$2,416	$0	$0	$0	15
16	GPECBA - CPUC Reimbursement Subaccount	$0	$0	$0	$0	$0	$0	16
17	Gas Meter Reading Costs Balancing Account	$26,767	$26,767	$0	$26,414	$26,414	$0	17
18	Gas Operational Cost Balancing Account	$9,908	$3,908	$6,000	$11,187 (5)	$4,412	$6,775	18
19	Pension Contribution Balancing Account	$0	$0	$0	$0	$0	$0	19
20	TID Almond Power Plant Balancing Account	($1,265)	($817)	($448)	($851)	($336)	($515)	20
21	Revised Customer Energy Statement Balancing Account	($4,361)	($4,210)	($151)	$293	$116	$177	21
22	GT&S Revenue Sharing Mechanism	$10,986 (4)	$5,493	$5,493	$5,054 (6)	$2,527	$2,527	22
23	**Subtotal Transportation Balancing Accounts**	**$174,813**	**$132,406**	**$42,407**	**$147,557**	**$117,518**	**$30,039**	23
	PUBLIC PURPOSE PROGRAM (PPP) SURCHARGE BALANCING ACCOUNTS (7)							
24	PPP-Energy Efficiency	$8,340	$7,505	$835	$4,195	$3,775	$420	24
25	PPP-Low Income Energy Efficiency	$1,125	$1,012	$113	($2,782)	($2,503)	($279)	25
26	PPP-Research Development and Demonstration	($196)	($125)	($71)	($43)	($27)	($16)	26
27	California Alternate Rates for Energy Account	($18,564)	($11,098)	($7,466)	($22,448)	($13,319)	($9,129)	27
28	**Subtotal Public Purpose Program Balancing Accounts**	**($9,295)**	**($2,706)**	**($6,589)**	**($21,078)**	**($12,074)**	**($9,004)**	28
29	**TOTAL BALANCING ACCOUNTS**	**$165,518**	**$129,700**	**$35,818**	**$126,479**	**$105,444**	**$21,035**	29

Footnotes:

1. These balances are the recorded balances as of December 2012. The 12/12 ending balances that were provided in the 2013 AGT AL 3353-G were the forecasted balances (based on recorded balances through November 2012).
2. On October 18, 2013, the Energy Division approved Advice 3406-G which approved the closure of the Noncore Distribution Fixed Cost Balancing Account and the transfer of its balance to the NCA-Distribution subaccount.
3. This amount reflects the total forecast balance of the AB 32 Cost of Implementation Fee Core subaccount in the CFCA and the Noncore subaccount of the NCA. The total forecast balance is allocated on an equal-cents-per therm basis.
4. The balance shown is the September 30, 2013 recorded balance, which will be transferred evenly (50/50) to the CFCA and NCA after the approval of the AGT advice letter.
5. The account was called Electricity Cost Balancing Account in December 2012. It did not include the Compressor Station GHG Cost subaccount.
6. This amount represents the September 2012 recorded balance which was transferred to CFCA and NCA evenly.
7. The PPP-related balances (based on Sept 2013 recorded) were included in the 2014 PPP Gas Surcharge filed in AL 3426-G on October 31, 2013.

Notes:
A positive balance represents an under-collection. A negative balance represents an over-collection.
Some numbers may not add precisely due to rounding.

ATTACHMENT 3
PACIFIC GAS AND ELECTRIC COMPANY
January 1, 2014 Annual Gas True-Up Filed Dec

AVERAGE END-USER GAS TRANSPORTATION RATES(1) AND PUBLIC PURPOSE PROGRAM SURCHARGES(2)
($/th; Annual Class Averages)(3)

Line No.	Customer Class	APRIL 1, 2013 FILING - CORE DEAVERAGING, RESIDENTIAL WGSP, AB32 COMPRESSOR (A)			January 1, 2014 Annual Gas True-Up Filed Dec			Percentage Change From April 1, 2013		
		Transportation(1)	G-PPPS (2)	Total	Transportation	G-PPPS	Total	Transportation	G-PPPS	Total
	RETAIL CORE									
1	Residential Non-CARE	$.624	$.066	**$.689**	$.643	$.084	**$.727**	3.0%	28.0%	5.4%
2	Small Commercial Non-CARE	$.387	$.039	**$.425**	$.405	$.044	**$.449**	4.7%	14.5%	5.6%
3	Large Commercial	$.185	$.071	**$.257**	$.203	$.092	**$.295**	9.6%	28.3%	14.8%
4	NGV1 - (uncompressed service)	$.143	$.024	**$.167**	$.162	$.026	**$.188**	13.2%	6.1%	12.1%
5	NGV2 - (compressed service)	$1.397	$.024	**$1.421**	$1.447	$.026	**$1.472**	3.6%	6.1%	3.6%
	RETAIL NONCORE									
6	Industrial - Distribution	$.149	$.036	**$.185**	$.157	$.042	**$.199**	5.3%	16.8%	7.5%
7	Industrial - Transmission	$.053	$.030	**$.083**	$.062	$.034	**$.095**	17.2%	12.7%	15.6%
8	Industrial - Backbone	$.017	$.030	**$.047**	$.020	$.034	**$.054**	17.1%	12.7%	14.4%
9	Electric Generation - Transmission (G-EG-D/LT)	$.045		**$.045**	$.055		**$.055**	21.0%		21.0%
10	Electric Generation - Backbone (G-EG-BB)	$.016		**$.016**	$.019		**$.019**	20.5%		20.5%
11	NGV 4 - Distribution (uncompressed service)	$.149	$.024	**$.173**	$.157	$.026	**$.182**	5.3%	6.1%	5.4%
12	NGV 4 - Transmission (uncompressed service)	$.046	$.024	**$.070**	$.056	$.026	**$.081**	19.9%	6.1%	15.2%
	WHOLESALE CORE AND NONCORE (G-WSL) (1)									
13	Alpine Natural Gas	$.044		**$.044**	$.056		**$.056**	25.6%		25.6%
14	Coalinga	$.045		**$.045**	$.057		**$.057**	25.6%		25.6%
15	Island Energy	$.063		**$.063**	$.076		**$.076**	19.5%		19.5%
16	Palo Alto	$.040		**$.040**	$.052		**$.052**	28.8%		28.8%
17	West Coast Gas - Castle	$.155		**$.155**	$.178		**$.178**	15.2%		15.2%
18	West Coast Gas - Mather Distribution	$.182		**$.182**	$.209		**$.209**	14.9%		14.9%
19	West Coast Gas - Mather Transmission	$.048		**$.048**	$.059		**$.059**	24.8%		24.8%

(1) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable). Transport only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

(2) D. 04-08-010 authorized PG&E to remove the gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, energy efficiency, Research Development and Demonstration program and BOE/CPUC Administration costs from transportation rates and into its own separate surcharge tariff. Certain customers are exempt from paying the PPP surcharge; see tariff G-PPPS for details. G-PPPS rates are determined annually in PG&E's PPP Filing.

(3) Rates are rounded to 3 decimals for viewing ease. Percentage rate changes are calculated on a 5-digit basis.

(4) CARE Customers receive a 20% discount off of PG&E's total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates and cost recovery of the California Solar Initiative Thermal Program.

Attachment 4
PACIFIC GAS AND ELECTRIC COMPANY
JANUARY 1, 2014 ANNUAL GAS TRUE-UP FILED DEC
SUMMARY OF RATES (excluding procurement) BY CLASS BY MAJOR ELEMENTS
($/th; Annual Class Averages)[8]

		Core Retail					Noncore Retail						
		Non-CARE			G-NGV1	G-NGV2	Industrial			G-NGV 4		Electric Generation	
		Residential	Sml Com.	Lg. Comm.	(Uncompressed)	(Compressed)	Distribution	Transmission	BB-Level Serv.	Distribution	Transmission	Dist./Trans.	BB-Level Serv.
	TRANSPORTATION CHARGE COMPONENTS												
1	Local Transmission (1)	$.04333	$.04333	$.04333	$.04333	$.04333	$.02121	$.02121	$.00069	$.02121	$.02121	$.02121	$.00069
2	Self Generation Incentive Program	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090	$.00090
3	CPUC and AB32 Cost of Implementation Fee (3)	$.00158	$.00158	$.00158	$.00158	$.00158	$.00158	$.00158	$.00158	$.00158	$.00158	$.00092	$.00092
4	Balancing Accounts (2)	$.08057	$.05230	$.02531	$.03045	$.10108	$.00728	$.01000	$.01029	$.00728	$.01029	$.00903	$.00903
5	PSEP	$.03667	$.03667	$.03667	$.03667	$.03667	$.01979	$.01979	$.00540	$.01979	$.01979	$.01979	$.00540
6	Distribution - Annual Average (6)	$.47977	$.21110	$.09100	$.04798	$1.26332	$.09827	$.00638		$.09827		$.00200	$.00200
7	VOLUMETRIC RATE - Average Annual	$.64281	$.34586	$.19879	$.16090	$1.44688	$.14903	$.05986	$.01886	$.14903	$.05377	$.05385	$.01894
8	CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4)		$.05888	$.00449	$.00120		$.00788	$.00186	$.00157	$.00788	$.00186	$.00109	$.00019
9	CLASS AVERAGE TRANSPORTATION RATE	$.64281	$.40475	$.20328	$.16210	$1.44688	$.15691	$.06172	$.02044	$.15691	$.05564	$.05494	$.01913
10	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)	$.08387	$.04441	$.09160	$.02554	$.02554	$.04168	$.03371	$.03371	$.02554	$.02554		
11	END-USE RATE (7)	$.72668	$.44916	$.29488	$.18764	$1.47242	$.19859	$.09543	$.05415	$.18245	$.08118	$.05494	$.01913

		Wholesale						
				WC Gas Mather		Island		WC Gas
		Coalinga	Palo Alto	Dist.	Trans.	Energy	Alpine	Castle
	TRANSPORTATION CHARGE COMPONENTS							
12	Local Transmission (1)	$.02121	$.02121	$.02121	$.02121	$.02121	$.02121	$.02121
13	Self Generation Incentive Program	WHOLESALE CUSTOMERS EXCEPT FROM SGIP RATE COMPONENT						
14	CPUC and AB32 Cost of Implementation Fee (3)							
15	Balancing Accounts (2)	$.00885	$.00893	$.00480	$.00893	$.00897	$.00882	$.00572
16	PSEP	$.01979	$.01979	$.01979	$.01979	$.01979	$.01979	$.01979
17	Distribution - Annual Average			$.15339				$.11584
18	VOLUMETRIC RATE - Average Annual	$.04986	$.04993	$.19919	$.04993	$.04997	$.04983	$.16257
19	CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4)	$.00670	$.00179	$.00954	$.00954	$.02589	$.00585	$.01540
20	CLASS AVERAGE TRANSPORTATION RATE	$.05656	$.05173	$.20874	$.05947	$.07586	$.05567	$.17797
21	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)							
22	END-USE RATE	$.05656	$.05173	$.20874	$.05947	$.07586	$.05567	$.17797

NOTES
(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2014 Annual Gas True-Up Filing AL 3447-G Attachment 6, Appendix B, Table 11.
(2) Based on November recorded balances and forecasted through December.
(3) CPUC Fee based on Resolution M-4819, effective July 1, 2007 (including FF&U). G-EG customers pay a reduced CPUC fee per the 2010 BCAP D.10-06-035.
(4) Adopted in Decision 11-04-031 based on Appendix B, Table 12; updated in the 2014 Annual Gas True-Up Filing AL 3447-G Attachment 6, Appendix B, Table 12.
(5) Decision 04-08-010 ordered the removal of PPP cost recovery from transportation rates. On March 1, 2005 PG&E began to treat PPP as a tax. AL 3426-G updated PG&E's 2014 PPP Surcharges effective January 1, 2014.
(6) The G-NGV2 Distribution rate component incudes the cost of compression, station operations and maintanance, and state/federal gas excise taxes, and the average A-10 electric rate.
(7) CARE Customers receive a 20% discount off of PG&E's total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates and cost recovery of the California Solar Initiative Thermal Program.
(8) Rates are unrounded

Attachment 5

PACIFIC GAS AND ELECTRIC COMPANY
January 1, 2014 Annual Gas True-Up Filed Dec
ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES
($000)

Line No.	GAS GRC, ATTRITION, PENSION & COST OF CAPITAL DISTRIBUTION-LEVEL REVENUE REQUIREMENTS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
1	Customer	$655,857	572,042	76,233	1,631	66	0	649,972	4,036	229	0	1,419	0	0	0	0	0	0	0	0	5,685
2	+ Distribution	$544,458	379,724	122,277	5,396	915	0	508,313	23,249	8,818	0	3,905	0	0	0	0	96	0	77	0	36,145
3	+ G-NGV2 Compression Cost	$2,942	0	0	0	0	2,942	2,942	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Allocation of Base Distribution Franchise Fees	$11,893	9,409	1,962	69	10	29	11,480	270	89	0	53	0	0	0	0	1	0	1	0	414
5	Allocation of Base Distribution Uncollectibles Expense	$3,784	2,994	624	22	3	9	3,653	86	28	0	17	0	0	0	0	0	0	0	0	131
6	Totals Before Core Averaging	$1,218,734	964,169	201,097	7,118	994	2,980	1,176,359	27,641	9,166	0	5,393	0	0	0	0	97	0	78	0	42,375
7	Re-Allocation Due to Core Averaging*	($0)	(12,824)	12,824	0	0	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Final Allocation of Distribution Revenue Requirement**	**$1,218,734**	**$951,346**	**$213,921**	**$7,118**	**$994**	**$2,980**	$1,176,359	**$27,641**	**$9,166**	**$0**	**$5,393**	**$0**	**$0**	**$0**	**$0**	**$97**	**$0**	**$78**	**$0**	$42,375
9	**Distribution-Level Revenue Requirement Allocation %**	100.00000%	78.06015%	17.55271%	0.58407%	0.08159%	0.24454%	96.52306%	2.26801%	0.75207%	0.00000%	0.44251%	0.00000%	0.00000%	0.00000%	0.00000%	0.00797%	0.00000%	0.00638%	0.00000%	3.47694%

Line No.	CUSTOMER CLASS COSTS WITHOUT RATE COMPONENTS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
10	Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount	$44,994	$36,388	$8,182	$272	$38	$114	$44,994	$0	$0	$0	$0.000	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Core Fixed Cost Acct. Bal. - Core Cost Subaccount - ECPT	4,729	3,282	1,293	122	33	0	4,729	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
12	CFCA-Winter Gas Savings Program Transportation Portion	0	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
13	Noncore Customer Class Charge Account - ECPT	-3,175	0	0	0	0	0	0	-186	-1,025	-8	($1,925.570)	-4	-2	-23	0	-1	0	0	-25	-3,175
14	Noncore Customer Class Charge Account - Interim Relief	-1,007	0	0	0	0	0	0	-657	-218	0	($128.124)	0	0	0	0	-2	0	-2	0	-1,007
15	NC Distribution Fixed Cost Acct.	0	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
16	CA Solar Hot Water Heating	4,598	1,711	879	83	22	0	2,696	289	1,595	13	$0.000	6	0	0	0	0	0	0	0	1,902
17	Lawrence Livermore Lab	0	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
18	Hazardous Substance Balance	51,776	14,170	5,582	525	142	0	20,420	1,835	10,125	82	$19,016.062	37	17	225	4	7	4	5	250	31,357
19	Non-Tariffed Products and Services	-209	-145	-57	-5	-1	0	-209	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
20	Core Brokerage Fee Credit (Gas Brokerage Costs w/o FF&U)	-5,470	-3,796	-1,495	-141	-38	0	-5,470	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
21	Core Brokerage Fee Credit (Sales/Marketing Costs w/o FF&U)	-1,028	-905	-121	-3	0	0	-1,028	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
22	Affiliate Transfer Fee Account	0	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
23	Balancing Charge Account	-25	-7	-3	0	0	0	-10	-1	-5	0	($9.221)	0	0	0	0	0	0	0	0	-15
24	G-10 Procurement-related Employee Discount Allocated	1,042	285	112	11	3	0	411	37	204	2	$382.835	1	0	5	0	0	0	0	5	631
25	Brokerage Fee Balance Account	736	511	201	19	5	0	736	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
26	Adjust. Mechanism Costs Determined Other Proceedings	0.0000	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
27	G-10 Procurement-related Employee Discount	-1,042	-1,042	0	0	0	0	-1,042	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
28	TID Almond Power Plant	-1,265	-614	-189	-12	-3	0	-817	-43	-172	0	($223.926)	-1	-1	-7	0	0	0	0	-8	-448
29	RCESBA-G	-4,361	-3,450	-720	-25	-4	-11	-4,210	-99	-33	0	($19.299)	0	0	0	0	0	0	0	0	-152
30	Gas Operational Cost Balancing Account	9,908	2,712	1,068	101	27	0	3,908	351	1,938	16	$3,639.058	7	3	43	1	1	1	1	48	6,001
31	WGSP Balancing Account	5,490	5,187	275	28	0	0	5,490	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
32	GT&S Revenue Sharing Mechanism	10,986	3,812	1,502	141	38	0	5,493	321	1,774	14	$3,331.049	6	3	39	1	1	1	1	44	5,493
33	Gas Meter Reading Costs Balancing Account	26,767	21,647	4,868	162	23	68	26,767	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
34	Self Gen Incentive Program Forecast Period Cost	6,480	1,782	702	66	18	0	2,569	231	1,274	10	$2,392.043	5	0	0	0	0	0	0	0	3,911
35	Subtotals of Items Transferred to CFCA and NCA	149,924	81,526	22,081	1,343	304	171	105,425	2,078	15,456	128	$26,454.905	57	21	282	5	6	5	4	314	44,499
36	Re-Allocation Due to Core Averaging	0	-764	764	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
37	Alloc. After Core Averaging	149,924	80,762	22,845	1,343	304	171	105,425	2,078	15,456	128	$26,454.905	57	21	282	5	6	5	4	314	44,499
38	Franchise Fees and Uncoll. Exp. on Items Above	1,953	1,052	298	18	4	2	1,374	27	201	2	$344.734	1	0	3	0	0	0	0	3	579
39	Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs	151,877	81,814	23,143	1,361	308	173	106,799	2,106	15,657	130	$26,799.639	58	21	285	5	6	5	4	317	45,078
40	Total of Items Collected via CFCA, NCA, and NDFCA	$1,370,611	$1,033,160	$237,064	$8,479	$1,302	$3,154	$1,283,159	$29,747	$24,823	$130	$32,192.668	$58	$21	$285	$5	$104	$5	$82	$317	$87,452

Line No.	CUSTOMER CLASS COSTS WITH THEIR OWN RATE COMPONENTS ALLOCATED USING BCAP THROUGHPUT	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
41	Mobile Home Parks	0	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
42	CEE Incentive	$3,982	$3,474	$463	$10	$0	$0	$3,947	$25	$1	$0	$8.619	$0	$0	$0	$0	$0	$0	$0	$0	$35
43	AB32 ARB Implementation Fee	4,959.837	1,765	695	65	18	0	2,544	228	1,261	10	$911.843	5	0	0	0	0	0	0	0	2,416
44	Smart Meter™ Project Forecast Period Costs	79,202	64,052	14,403	479	268	0	79,202	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
45	SmartMeter™ Project Balancing Account (SBA-G)	15,929	12,882	2,897	96	54	0	15,929	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
46	SmartMeter Opt-Out	0	0	0	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
47	CPUC FEE	3,210	1,368	538	51	14	0	1,970	177	977	8	$74.705	4	0	0	0	0	0	0	0	1,240
48	Subtotals for Customer Class Charge Items	107,283	83,541	18,996	702	353	0	103,592	430	2,240	18	$995.167	8	0	0	0	0	0	0	0	3,691
49	Re-Allocation Due to Core Averaging	0	-998	998	0	0	0	0	0	0	0	$0.000	0	0	0	0	0	0	0	0	0
50	Allocation after Remaining Core Averaging	107,283	82,543	19,994	702	353	0	103,592	430	2,240	18	$995.167	8	0	0	0	0	0	0	0	3,691
51	Franch. Fee and Uncoll. Exp. on Items Above	1,398	1,076	261	9	5	0	1,350	6	29	0	$12.968	0	0	0	0	0	0	0	0	48
52	Subtotals of Other Costs	108,681	83,618	20,255	711	358	0	104,942	436	2,269	18	$1,008.135	8	0	0	0	0	0	0	0	3,739
53	Allocation of Total Transportation Costs	$1,479,292	$1,116,778	$257,318	$9,190	$1,660	$3,154	$1,388,100	$30,182	$27,092	$148	$33,200.803	$66	$21	$285	$5	$104	$5	$82	$317	$91,192

Line No.	CUSTOMER CLASS COST FOR PIPELINE SAFETY ENHANCEMENT ALLOCATED BASED ON GAS ACCORD THROUGHPUT	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
54	Local Transmission Expense (Forecast Period Cost)	$134,616	$59,440	$23,373	$2,404	$664	$0	$85,881	$3,832	$20,692	$0	$23,592	$84	$37	$460	$10	$14	$6	$9	$513	$48,735
55	Local Transmission Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
56	Backbone Transmission Expense (Forecast Period Cost)	40,770	12,085	4,752	489	135	0	17,461	1,310	7,075	56	14,656	29	13	157	3	5	2	3	175	23,308
57	Backbone Transmission Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
58	Storage (Forecast Period Cost)	5,572	2,278	896	92	25	0	3,291	128	692	6	1,434	3	1	15	0	0	0	0	17	2,281
59	Storage Balancing Account	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
60	Subtotal of Pipeline Safety Enhacement Cost	$180,958	$73,804	$29,021	$2,985	$825	$0	$106,634	$5,270	$28,459	$62	$39,682	$115	$51	$632	$13	$19	$9	$13	$705	$74,324

Line No.	RECONCILIATION WITH REVENUE REQUIREMENTS TABLE FOR END-USER TRANSPORTATION TOTALS	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
61	WGSP-T Rebate Recovery (w/o FF&U)	(0)	(0)	(0)	(0)			(0)													0
62	Franchise Fees and Uncollectibles Expense	(0)	(0)	(0)	(0)			(0)													0
63	Total End-User Transportation Rev. Req. Excluding Gas Accord	$1,660,250	$1,190,582	$286,339	$12,175	$2,485	$3,154	$1,494,734	$35,452	$55,551	$210	$72,882	$181	$72	$917	$19	$122	$14	$94	$1,022	$165,516
	WGSP - T Marketing and Implementation	0	0	<--w F&U																	

Line No.	ADOPTED REVENUE REQUIREMENTS ALLOCATIONS FOR GAS ACCORD ITEMS IN TRANSPORTATION	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
64	Local Transmission	212,200	101,460	31,478	1,931	471		135,339	7,160	28,279		39,953	122	116	1,112	33	45	17	24	1,279	76,861
65	Customer Access Charge	5,026	0	0	0			0	0	2,650		2,267		17	57	4	9	12	10	90	5,026
66	Total End-User Gas Accord Transportation Costs	217,226	101,460	31,478	1,931	471	0	135,339	7,160	30,929	0	42,220	122	134	1,169	37	54	28	34	1,369	81,887
67	Gross End-User Transportation Costs in Rates	1,877,476	1,292,042	317,817	14,105	2,956	3,154	1,630,074	42,612	86,480	210	115,102	303	206	2,087	56	176	43	129	2,391	247,403
68	Less Forecast CARE Discount recovered In PPP Surcharges	108,850	108,850					108,850													0
69	Net End-User Transportation Costs in Rates	$1,768,626	$1,183,191	$317,817	$14,105	$2,956	$3,154	$1,521,223	$42,612	$86,480	$210	$115,102	$303	$206	$2,087	$56	$176	$43	$129	$2,391	$247,403

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT 5 (continued)
January 1, 2014 Annual Gas True-Up Filed Dec
ALLOCATION OF GAS END-USE TRANSPORTATION REVENUE REQUIREMENTS AND PUBLIC PURPOSE PROGRAM SURCHARGE REVENUES ACROSS CLASSES
($000)

Line No.	ALLOCATION OF PUBLIC PURPOSE PROGRAM SURCHARGES UNDER PER PG&E AL 3161-G	TOTAL	Residential*	Small Commercial*	Large Commercial	Core NGV	Compression Cost for G-NGV2	Subtotal Core	Industrial Distribution	Industrial Transmission	Industrial Backbone	Electric Gen	Noncore NGV	Coalinga	Palo Alto	Alpine Natural Gas	WC Gas Mather**	Island Energy	WC Gas Castle**	Other Wholesale	Noncore & Wholesale
70	PPP-EE Surcharge	74,332	58,588	5,962	2,337	0		66,887	1,998	5,404	44		0								7,445
71	PPP-EE Balancing Account	8,340	6,574	669	262	0		7,505	224	606	5		0								835
72	PPP-ESA Surcharge	67,982	53,583	5,453	2,137	0		61,173	1,827	4,942	40		0								6,809
73	PPP-ESA Balancing Account	1,125	887	90	35	0		1,012	30	82	1		0								113
74	PPP - RD&D Programs	10,700	4,779	1,852	172	43		6,846	602	3,214	26		12								3,854
75	PPP - RD&D Balancing Account	(196)	(88)	(34)	(3)	(1)		(125)	(11)	(59)	(0)		(0)								-71
76	PPP-CARE Discount Allocation Set Annually	108,850	41,595	21,033	1,952	491		65,072	6,833	36,509	295		141								43,778
77	PPP-CARE Administration Expense	2,806	1,072	542	50	13		1,677	176	941	8		4								1,128
78	PPP-CARE Balancing Account	(18,564)	(7,094)	(3,587)	(333)	(84)		(11,098)	(1,165)	(6,226)	(50)		(24)								-7,466
79	PPP-Admin Cost for BOE and CPUC	379	169	66	6	2		242	21	114	1		0								137
80	Subtotal	255,754.45	160,065	32,046	6,616	464		199,191	10,535	45,526	368	0	134	0	0	0	0	0	0	0	56,563
81	Re-Allocation Due to Core Averaging	(0.00)	(2,508)	2,508	0	0		(0)	0	0	0	0	0	0	0	0	0	0	0	0	0
82	Allocation after Remaining Averaging	$255,754	$157,557	$34,554	$6,616	$464		$199,191	$10,535	$45,526	$368	$0	$134	$0	$0	$0	$0	$0	$0	$0	$56,563

Line No.			
83	Unbundled Gas Transmission and Storage Revenue Requirement	$170,384	
	TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES		
84	Total Transportation, PPPS, and Unbundled Costs	2,194,764	(Total of lines 69, 82, and 83)
85	Cross-check with Gas Revenue Requirement Table	2,194,764	Attachment 1 Row 38
86	Difference	-1	(rounding due to allocating $)
87			
88			

* Residential and Small Commercial Classes are 10% averaged
** Wholesale Customer West Coast Gas is allocated 90% of its full distribution costs as of January 2014.

Advice 3447-G
December 24, 2013

Gas Accord V Settlement

(A.09-09-013)

Attachment 6 - Appendix A

Update

2011 Rates - Reflects (May 1, 2011) Late implementation of the GA V Settlement as filed in Advice 3200-G and 3201-G

2012 - 2014 Rates - Reflect treatment of costs as determined in PG&E's 2011 General Rate Case in Advice 3257-G-A.

2013 - 2014 Rates - Reflect treatment of costs as proposed in PG&E's 2013 Cost of Capital Proceeding (A.12-04-018).

No Change from the November 3, 2013 Advice Filing (AL3430-G).

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Gas Accord V Settlement Agreement

Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-1
Core and Core Wholesale
Delivery Point Backbone Capacity Assignments/Options

		Gas Accord IV	Gas Accord V			
Line No.		Core Redwood Annual Capacity (MDth/d)	Allocation Factors	Core Redwood Annual Capacity (MDth/d)	Core Baja Annual Capacity (MDth/d)	Core Baja Seasonal Capacity (MDth/d)
1	CORE and CTAs	608.766	98.89%	608.766	348.000	321.000
2	WHOLESALE - Core					
3	Palo Alto	5.898	0.96%	5.898	3.372	3.110
4	Coalinga	0.552	0.09%	0.552	0.316	0.291
5	West Coast Gas-Mather	0.171	0.03%	0.171	0.098	0.090
6	Island Energy	0.064	0.01%	0.064	0.037	0.034
7	Alpine Natural Gas	0.098	0.02%	0.098	0.056	0.052
8	West Coast Gas-Castle	0.051	0.01%	0.051	0.029	0.027
9	Subtotal	6.834	1.11%	6.834	3.907	3.604
10	TOTAL	615.600	100.00%	615.600	351.907	324.604

Appendix A
(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-2
Firm Storage Capacity Assignments
Core, Load Balancing, and Market Storage Services

Line No.	Service	Annual Injection Storage Units	Inventory	Annual Withdrawal Storage Units
1	Monthly Balancing Service	76	4.1	76
2	Core Firm Storage	157	33.5	1,111
3	Core Firm Storage Counter Cyclical	50	0	50
4	Market Storage (Traditional)	194	9.0	300
5	Market Storage Counter Cyclical (Traditional)	194	0	300
6	Market Storage (Gill Ranch)	62	3.2	105

Appendix A

Effective January 1, 2014

Table A-3

GT&S Revenue Requirement

Including Core and Noncore Revenue Responsibility

($ Thousand)

Line		GA V Settlement	GA V with 2013 COC and GHG Compressor Cost				GA V with 2013 COC and GHG Compressor Cost, excluding Non-Operational Adder Projects.			
No.		2011 (9)	2011	2012	2013 (10)	2014 (11)	2011	2012	2013 (10)	2014 (11)
	Core Revenue Requirements									
1	Backbone Transmission Base (1) (2) (5) (6)	94,929	93,414	95,901	94,506	96,208	86,621	95,901	94,506	96,208
2	Backbone Transmission Adders	-	-	-	3,173	3,335	-	-	-	-
3	Subtotal Backbone Transmission	94,929	93,414	95,901	97,679	99,543	86,621	95,901	94,506	96,208
4	Local Transmission Base	124,872	122,972	131,618	128,003	130,693	113,620	131,618	128,003	130,693
5	Local Transmission Adder (3) (7)	5,514	5,514	5,785	9,602	13,319	5,514	5,395	4,850	4,646
6	Subtotal Local Transmission	130,386	128,486	137,403	137,605	144,013	119,134	137,013	132,853	135,339
7	Storage (4) (8)	49,255	48,689	50,121	49,492	50,603	48,689	50,121	49,492	50,603
8	Customer Access Charge	-	-	-	-	-	-	-	-	-
9	Total Core (12)	$274,571	$270,589	$283,425	$284,776	$294,159	$254,444	$283,036	$276,851	$282,150
		53.4%	53.3%	53.0%	52.8%	52.9%	53.3%	53.0%	52.8%	52.8%
	Noncore / Unbundled Revenue Requirements									
10	Backbone Trans. Base w/o G-XF Contracts	124,818	123,774	132,655	128,787	129,574	114,758	132,655	128,787	129,574
11	Backbone Transmission Adders	-	-	-	4,656	5,158	-	-	-	-
12	Subtotal Backbone Transmission	124,818	123,774	132,655	133,444	134,732	114,758	132,655	128,787	129,574
13	G-XF Contracts	6,879	6,875	6,448	5,978	5,831	6,875	6,448	5,978	5,831
14	G-XF Contract Adders	-	-	-	-	43	-	-	-	-
15	G-XF Contracts Subtotal	6,879	6,875	6,448	5,978	5,874	6,875	6,448	5,978	5,831
16	Subtotal Backbone Transmission (5) (6)	131,698	130,648	139,103	139,422	140,606	121,633	139,103	134,765	135,405
17	Local Transmission Base	64,594	63,623	68,774	70,132	74,223	58,784	68,774	70,132	74,223
18	Local Transmission Adder (3) (7)	2,853	2,853	3,023	5,261	7,564	2,853	2,819	2,657	2,638
19	Subtotal Local Transmission	67,447	66,476	71,797	75,392	81,787	61,637	71,593	72,789	76,861
20	Storage (4) (8)	35,795	35,513	35,729	34,615	34,980	35,513	35,729	34,615	34,980
21	Customer Access Charge	4,691	4,590	4,821	4,860	5,026	4,590	4,821	4,860	5,026
22	Total Noncore / Unbundled (12)	$239,631	$237,227	$251,449	$254,288	$262,398	$223,373	$251,246	$247,029	$252,271
		46.6%	46.7%	47.0%	47.2%	47.1%	46.7%	47.0%	47.2%	47.2%
	Total									
23	Backbone Transmission Base w/o G-XF Contracts	219,747	217,188	228,556	223,294	225,781	201,379	228,556	223,294	225,781
24	Backbone Transmission Adders	-	-	-	7,829	8,493	-		-	-
25	Subtotal Backbone Trans. w/o G-XF Contracts	219,747	217,188	228,556	231,123	234,274	201,379	228,556	223,294	225,781
26	G-XF Contracts	6,879	6,875	6,448	5,978	5,831	6,875	6,448	5,978	5,831
27	G-XF Contract Adders	-	-	-	-	43	-	-	-	-
28	G-XF Contracts Subtotal	6,879	6,875	6,448	5,978	5,874	6,875	6,448	5,978	5,831
29	Subtotal Backbone Transmission (5) (6)	226,627	224,062	235,004	237,101	240,148	208,254	235,004	229,271	231,612
30	Local Transmission Base	189,466	186,595	200,392	198,135	204,916	172,404	200,392	198,135	204,916
31	Local Transmission Adder (less 5%) (3) (7)	8,367	8,367	8,808	14,862	20,884	8,367	8,214	7,508	7,284
32	Subtotal Local Transmission	197,833	194,962	209,200	212,997	225,800	180,771	208,606	205,643	212,200
33	Storage (4) (8)	85,051	84,202	85,850	84,106	85,583	84,202	85,850	84,106	85,583
34	Customer Access Charge	4,691	4,590	4,821	4,860	5,026	4,590	4,821	4,860	5,026
35	Total GT&S (12)	$514,202	$507,817	$534,874	$539,064	$556,557	$477,817	$534,281	$523,880	$534,421
		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%		

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Gas Accord V Settlement Agreement

Appendix A

Effective January 1, 2014

Table A-3 (continued)

GT&S Revenue Requirement

Including Core and Noncore Revenue Responsibility

($ Thousand)

Notes

(1) 2010-2014 Core Backbone revenue responsibility assumes an average 100% load factor.

(2) Beginning in 2011, Core eliminated its annual Silverado capacity holdings.

(3) The Gas Accord V adopted 2011 local transmission rate includes a base rate component plus a rate adder for the Line 406 adder project.

(4) 2010-2014 storage revenue requirements include carrying costs on noncycled working gas and cycle gas.

(5) Backbone revenue requirements do not reflect the impact of PG&E's proposed revenue sharing mechanism.

(6) Backbone rates include load balancing costs.

(7) The Gas Accord V Settlement local transmission revenue requirements have been reduced by the following amounts that represent the fractional-year revenue requirements associated with local transmission adder projects: 2011 - $145 thousand; 2012 - $614 thousand; 2013 - $529 thousand.

(8) The Gas Accord V Settlement storage revenue requirements include the following non-base revenues for carrying costs on noncycled working gas and and cycled gas for storage balancing: 2011 - $1,852 million; 2012 - $2,867 million; 2013 - $3,042 million; 2014 - $3,584 million.

(9) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(10) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(11) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

(12) Totals may not agree with the sum of the numbers shown due to rounding.

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Gas Accord V Settlement Agreement

Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-4

Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates

Local Transmission Projects

Line No.	Project (Planned Operation Date)	Estimated Capital ($ million)	Local Transmission Revenue Requirement Caps, ($000) per year											
			Core				Noncore				Total			
1			2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
2	Line 304, 4.6 miles 12" pipe, Stockton Area (September 2011)	$4.7	----	390	351	344	----	204	192	195	----	593	543	539
3	Line 406, 2 miles 8" pipe, Merced Area (November 2010)	$58.6	5,514	5,395	4,850	4,646	2,853	2,819	2,657	2,638	8,367	8,214	7,508	7,284
4	Line 407 Phase 1 , 12 miles 30" pipe, Roseville Area (November 2012)	$51.9	----	----	4,400	4,194	----	----	2,411	2,382	----	----	6,811	6,576
5	Line 407 Phase 2, 14.3 miles 30" pipe, Yolo Area (November 2013)	$51.0	----	----	----	4,136	----	----	----	2,349	----	----	----	6,484
6	Total	$166.2	5,514	5,785	9,602	13,319	2,853	3,023	5,261	7,564	8,367	8,808	14,862	20,884

		Local Transmission Rate Adder, $ per Dth							
		Core				Noncore			
7	Project	2011	2012	2013	2014	2011	2012	2013	2014
8	Line 304, 4.6 mile 12" pipe	----	0.0013	0.0012	0.0012	----	0.0006	0.0006	0.0006
9	Line 406, 2 miles 8" pipe	0.0189	0.0185	0.0166	0.0160	0.0091	0.0085	0.0078	0.0078
10	Line 407 Phase 1 , 12 miles 30" pipe	----	----	0.0151	0.0144	----	----	0.0071	0.0071
11	Line 407 Phase 2, 14.3 miles 30" pipe	----	----	----	0.0142	----	----	----	0.0070
12	Total	0.0189	0.0198	0.0330	0.0458	0.0091	0.0091	0.0155	0.0224

Backbone Transmission Projects

			Total				
			2011	2012	2013	2014	2015 (1)
13	Delevan K3/Gerber - L400, NOx Emissions, Selective Catalytic Reduction System (December 2013)	$4.1	----	----	----	493	----
14	Delevan K3/Gerber - L401, NOx Emissions, Selective Catalytic Reduction System (Decenber 2013)	$4.0	----	----	----	518	----
15	P03107 Topock, P-Units Replacement, Rebuild of compressor station power units (June 2014)	$10.0	----	----	----	----	1,230
16	P02158-Topock K-Units Replacement-Ph 1, NOx Emissions, Compressor Engine Replacement (December 2012)	$60.0	----	----	7,829	7,525	----
17	P02158-Topock K-Units Replacement-Ph 2 (September 2014)	$30.0	----	----	----	----	3,741
18	Total	$108.1	----	----	7,829	8,536	4,971

(1) Consistent with Gas Accord V Settlement Agreement, Section 2.4 - "Interim Rates" should approved rates not be in place for GT&S services by January 1, 2015, pursuant to a Commission order in the next GT&S Ratecase, a rate adjustment will be made for designated backbone and local transmission "Adder" project that may go into service in 2014.

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Gas Accord V Settlement Agreement

Appendix A

Rates Effective January 1, 2014

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)
G-AFT: Annual Firm Transportation On-System

		Noncore Redwood Path									
		MFV					SFV				
Line No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.4087	5.4576	5.2084	5.2050		8.3095	8.3437	7.9034	7.8577	
3	Usage Charge	0.1038	0.1032	0.0965	0.0952		0.0084	0.0083	0.0079	0.0080	
4	Total Charge	0.2816	0.2826	0.2678	0.2663		0.2816	0.2826	0.2678	0.2663	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0818	—	—	—	—	0.1235
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.4087	5.4576	5.2084	5.2050		8.3095	8.3437	7.9034	7.8577	
29	Usage Charge	0.1038	0.1032	0.0965	0.0952		0.0084	0.0083	0.0079	0.0080	
30	Total Charge	0.2816	0.2826	0.2678	0.2663		0.2816	0.2826	0.2678	0.2663	

		Noncore Baja Path									
		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.8930	6.0418	5.8953	5.9939		9.0536	9.2370	8.9457	9.0486	
3	Usage Charge	0.1129	0.1140	0.1090	0.1093		0.0089	0.0089	0.0087	0.0088	
4	Total Charge	0.3066	0.3126	0.3028	0.3063		0.3066	0.3126	0.3028	0.3063	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0818	—	—	—	—	0.1235
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.8930	6.0418	5.8953	5.9939		9.0536	9.2370	8.9457	9.0486	
29	Usage Charge	0.1129	0.1140	0.1090	0.1093		0.0089	0.0089	0.0087	0.0088	
30	Total Charge	0.3066	0.3126	0.3028	0.3063		0.3066	0.3126	0.3028	0.3063	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Appendix A

Rates Effective January 1, 2014

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)

G-AFT: Annual Firm Transportation On-System

		Core Redwood Path									
		MFV					SFV				
Line No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	4.7466	4.6534	4.4923	4.5126		6.5162	6.4678	6.3001	6.3780	
3	Usage Charge	0.0684	0.0693	0.0685	0.0705		0.0102	0.0096	0.0091	0.0092	
4	Total Charge	0.2244	0.2223	0.2162	0.2188		0.2244	0.2223	0.2162	0.2188	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0375	—	—	—	—	0.0530
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0001
17	Total Charge	—	—	—	—	0.0018	—	—	—	—	0.0018
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.1141	—	—	—	—	0.1612
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0002
25	Total Charge	—	—	—	—	0.0055	—	—	—	—	0.0055
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	4.7466	4.6534	4.4923	4.5126		6.5162	6.4678	6.3001	6.3780	
29	Usage Charge	0.0684	0.0693	0.0685	0.0705		0.0102	0.0096	0.0091	0.0092	
30	Total Charge	0.2244	0.2223	0.2162	0.2188		0.2244	0.2223	0.2162	0.2188	

		Core Baja Path									
		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.2811	5.2883	5.2276	5.3466		7.2499	7.3504	7.3313	7.5567	
3	Usage Charge	0.0758	0.0784	0.0794	0.0831		0.0111	0.0106	0.0102	0.0104	
4	Total Charge	0.2494	0.2523	0.2512	0.2588		0.2494	0.2523	0.2512	0.2588	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0375	—	—	—	—	0.0530
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0001
17	Total Charge	—	—	—	—	0.0018	—	—	—	—	0.0018
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.1141	—	—	—	—	0.1612
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0002
25	Total Charge	—	—	—	—	0.0055	—	—	—	—	0.0055
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.2811	5.2883	$5.2276	$5.3466		7.2499	7.3504	$7.3313	$7.5567	
29	Usage Charge	0.0758	0.0784	$0.0794	$0.0831		0.0111	0.0106	$0.0102	$0.0104	
30	Total Charge	0.2494	0.2523	$0.2512	$0.2588		0.2494	0.2523	$0.2512	$0.2588	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Gas Accord V Settlement Agreement

Appendix A

Rates Effective January 1, 2014

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)

G-AFT: Annual Firm Transportation On-System

		Silverado Path									
Line		MFV					SFV				
No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	3.2679	3.1639	3.1425	3.1566		4.8056	4.6413	4.4150	4.4293	
3	Usage Charge	0.0554	0.0545	0.0495	0.0500		0.0049	0.0059	0.0077	0.0082	
4	Total Charge	0.1628	0.1585	0.1528	0.1538		0.1628	0.1585	0.1528	0.1538	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	----	----	----	----		----	----	----	----	
8	Usage Charge	----	----	----	----		----	----	----	----	
9	Total Charge	----	----	----	----		----	----	----	----	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	----	----	----	----		----	----	----	----	
12	Usage Charge	----	----	----	----		----	----	----	----	
13	Total Charge	----	----	----	----		----	----	----	----	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	----	----	----	----	0.0201	----				
16	Usage Charge	----	----	----	----	0.0003	----				
17	Total Charge	----	----	----	----	0.0010	----				
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	----	----	----	----		----	----	----	----	
20	Usage Charge	----	----	----	----		----	----	----	----	
21	Total Charge	----	----	----	----		----	----	----	----	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	----	----	----	----	0.0611	----	----	----	----	0.0893
24	Usage Charge	----	----	----	----	0.0010	----	----	----	----	0.0001
25	Total Charge	----	----	----	----	0.0030	----	----	----	----	0.0030
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	3.2679	3.1639	3.1425	3.1566		4.8056	4.6413	4.4150	4.4293	
29	Usage Charge	0.0554	0.0545	0.0495	0.0500		0.0049	0.0059	0.0077	0.0082	
30	Total Charge	0.1628	0.1585	0.1528	0.1538		0.1628	0.1585	0.1528	0.1538	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Gas Accord V Settlement Agreement

Appendix A

Rates Effective January 1, 2014

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)

G-SFT: Seasonal Firm Transportation On-System Only

		Noncore Redwood Path									
		MFV					SFV				
Line No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	6.4905	6.5491	6.2501	6.2460		9.9714	10.0125	9.4840	9.4293	
3	Usage Charge	0.1245	0.1238	0.1159	0.1142		0.0101	0.0100	0.0095	0.0096	
4	Total Charge	0.3379	0.3392	0.3213	0.3196		0.3379	0.3392	0.3213	0.3196	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0323	—	—	—	—	0.0487
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0016	—	—	—	—	0.0016
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0981	—	—	—	—	0.1482
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0050	—	—	—	—	0.0050
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	6.4905	6.5491	6.2501	6.2460		9.9714	10.0125	9.4840	9.4293	
29	Usage Charge	0.1245	0.1238	0.1159	0.1142		0.0101	0.0100	0.0095	0.0096	
30	Total Charge	0.3379	0.3392	0.3213	0.3196		0.3379	0.3392	0.3213	0.3196	

		Noncore Baja Path									
		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	7.0717	7.2502	7.0744	7.1926		10.8643	11.0843	10.7348	10.8584	
3	Usage Charge	0.1354	0.1368	0.1308	0.1311		0.0107	0.0107	0.0104	0.0106	
4	Total Charge	0.3679	0.3752	0.3633	0.3676		0.3679	0.3752	0.3633	0.3676	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0323	—	—	—	—	0.0487
16	Usage Charge	—	—	—	—	0.0006	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0016	—	—	—	—	0.0016
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0981	—	—	—	—	0.1482
24	Usage Charge	—	—	—	—	0.0017	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0050	—	—	—	—	0.0050
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	7.0717	7.2502	7.0744	7.1926		10.8643	11.0843	10.7348	10.8584	
29	Usage Charge	0.1354	0.1368	0.1308	0.1311		0.0107	0.0107	0.0104	0.0106	
30	Total Charge	0.3679	0.3752	0.3633	0.3676		0.3679	0.3752	0.3633	0.3676	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)
G-SFT: Seasonal Firm Transportation On-System Only

Core Baja Path

		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	6.3373	6.3460	6.2731	6.4159		8.6999	8.8204	8.7976	9.0680	
3	Usage Charge	0.0910	0.0941	0.0952	0.0997		0.0133	0.0127	0.0122	0.0125	
4	Total Charge	0.2993	0.3027	0.3015	0.3106		0.2993	0.3027	0.3015	0.3106	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0450	—	—	—	—	0.0636
16	Usage Charge	—	—	—	—	0.0007	—	—	—	—	0.0001
17	Total Charge	—	—	—	—	0.0022	—	—	—	—	0.0022
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.1369	—	—	—	—	0.1935
24	Usage Charge	—	—	—	—	0.0021	—	—	—	—	0.0002
25	Total Charge	—	—	—	—	0.0066	—	—	—	—	0.0066
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	6.3373	6.3460	6.2731	6.4159		8.6999	8.8204	8.7976	9.0680	
29	Usage Charge	0.0910	0.0941	0.0952	0.0997		0.0133	0.0127	0.0122	0.0125	
30	Total Charge	0.2993	0.3027	0.3015	0.3106		0.2993	0.3027	0.3015	0.3106	

Silverado Path

		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	3.9215	3.7967	3.7710	3.7879		5.7687	5.5695	5.2980	5.3151	
3	Usage Charge	0.0665	0.0654	0.0594	0.0601		0.0058	0.0071	0.0092	0.0098	
4	Total Charge	0.1954	0.1902	0.1834	0.1846		0.1954	0.1902	0.1834	0.1846	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0241	—	—	—	—	0.0353
16	Usage Charge	—	—	—	—	0.0004	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0012	—	—	—	—	0.0012
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0733	—	—	—	—	0.1072
24	Usage Charge	—	—	—	—	0.0012	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0036	—	—	—	—	0.0036
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	3.9215	3.7967	3.7710	3.7879		5.7687	5.5695	5.2980	5.3151	
29	Usage Charge	0.0665	0.0654	0.0594	0.0601		0.0058	0.0071	0.0092	0.0098	
30	Total Charge	0.1954	0.1902	0.1834	0.1846		0.1954	0.1902	0.1834	0.1846	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

A.09-09-013
Gas Accord V Settlement Agreement
Appendix A
Rates Effective January 1, 2014

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)
G-AA: As Available Transportation On-System

Line No.		Redwood Path				
		2011 (2)	**2012**	**2013 (3)**	**2014 (4)**	**2015**
1	**Base Usage Charge ($/Dth)**	0.3379	0.3392	0.3213	0.3196	
2	**Adder Rates**					
3	Delevan K3/Gerber - L400	----	----	----	----	----
4	Delevan K3/Gerber - L401	----	----	----	—	—
5	P03107 Topock, P-Units Replacement	----	----	----	----	0.0016
6	P02158-Topock K-Units Replacement-Ph 1	----	----	----	----	----
7	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
8	**Total Base Usage Charge Plus Adders (1)**	0.3379	0.3392	0.3213	0.3196	

		Baja Path				
		2011 (2)	**2012**	**2013 (3)**	**2014 (4)**	**2015**
9	**Base Usage Charge ($/Dth)**	0.3679	0.3752	0.3633	0.3676	
10	**Adder Rates**					
11	Delevan K3/Gerber - L400	----	----	----	----	
12	Delevan K3/Gerber - L401	----	----	----	----	
13	P03107 Topock, P-Units Replacement	----	----	----	----	0.0016
14	P02158-Topock K-Units Replacement-Ph 1	----	----	----	----	
15	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
16	**Total Base Usage Charge Plus Adders (1)**	0.3679	0.3752	0.3633	0.3676	

		Silverado Path				
		2011 (2)	**2012**	**2013 (3)**	**2014 (4)**	**2015**
17	**Base Usage Charge ($/Dth)**	0.1954	0.1902	0.1834	0.1846	
18	**Adder Rates**					
19	Delevan K3/Gerber - L400	----	----	----	----	
20	Delevan K3/Gerber - L401	----	----	----	----	
21	P03107 Topock, P-Units Replacement	----	----	—	—	0.0012
22	P02158-Topock K-Units Replacement-Ph 1	----	----	----	----	
23	P02158-Topock K-Units Replacement-Ph 2	----	----	----	—	0.0036
24	**Total Base Usage Charge Plus Adders (1)**	0.1954	0.1902	0.1834	0.1846	

		Mission Path				
		2011 (2)	**2012**	**2013 (3)**	**2014 (4)**	**2015**
25	**Usage Charge ($/Dth)**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)
G-AAOFF: As Available Transportation Off-System

Line No.		Redwood, Silverado and Mission (From City Gate) Off-System - Noncore 2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Usage Charge ($/Dth)**	0.3379	0.3392	0.3213	0.3196	
2	**Adder Rates**					
3	Delevan K3/Gerber - L400	----	----	----	----	
4	Delevan K3/Gerber - L401	----	----	----	----	
5	P03107 Topock, P-Units Replacement	----	----	----	----	0.0016
6	P02158-Topock K-Units Replacement-Ph 1	----	----	----	----	
7	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
8	**Total Base Usage Charge Plus Adders (1)**	0.3379	0.3392	0.3213	0.3196	

		Mission Path (From On-System Storage) Off-System 2011 (2)	2012	2013 (3)	2014 (4)	2015
9	**Usage Charge ($/Dth)**	0.0000	0.0000	0.0000	0.0000	

		Baja Path Off-System - Noncore 2011 (2)	2012	2013 (3)	2014 (4)	2015
10	**Base Usage Charge ($/Dth)**	0.3679	0.3752	0.3633	0.3676	
11	**Adder Rates**					
12	Delevan K3/Gerber - L400	----	----	----	----	
13	Delevan K3/Gerber - L401	----	----	----	----	
14	P03107 Topock, P-Units Replacement	----	----	----	----	0.0016
15	P02158-Topock K-Units Replacement-Ph 1	----	----	----	----	
16	P02158-Topock K-Units Replacement-Ph 2	----	----	----	----	0.0050
17	**Total Base Usage Charge Plus Adders (1)**	0.3679	0.3752	0.3633	0.3676	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Appendix A

Rates Effective January 1, 2014

Table A-4 (Continued)

Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

(Topock Adder Projects In-Service 2014 or later)

G-AFTOFF: Annual Firm Transportation Off-System

		Redwood, Silverado and Mission Paths Off-System									
		MFV					SFV				
Line No.		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.4087	5.4576	5.2084	5.2050		8.3095	8.3437	7.9034	7.8577	
3	Usage Charge	0.1038	0.1032	0.0965	0.0952		0.0084	0.0083	0.0079	0.0080	
4	Total Charge	0.2816	0.2826	0.2678	0.2663		0.2816	0.2826	0.2678	0.2663	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0818	—	—	—	—	0.1235
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.4087	5.4576	5.2084	5.2050		8.3095	8.3437	7.9034	7.8577	
29	Usage Charge	0.1038	0.1032	0.0965	0.0952		0.0084	0.0083	0.0079	0.0080	
30	Total Charge	0.2816	0.2826	0.2678	0.2663		0.2816	0.2826	0.2678	0.2663	

		Baja Path Off-System									
		MFV					SFV				
		2011 (2)	2012	2013 (3)	2014 (4)	2015	2011 (2)	2012	2013 (3)	2014 (4)	2015
1	**Base Rates ($/Dth)**										
2	Reservation Charge	5.8930	6.0418	5.8953	5.9939		9.0536	9.2370	8.9457	9.0486	
3	Usage Charge	0.1129	0.1140	0.1090	0.1093		0.0089	0.0089	0.0087	0.0088	
4	Total Charge	0.3066	0.3126	0.3028	0.3063		0.3066	0.3126	0.3028	0.3063	
5	**Adder Rates**										
6	Delevan K3/Gerber - L400										
7	Reservation Charge	—	—	—	—		—	—	—	—	
8	Usage Charge	—	—	—	—		—	—	—	—	
9	Total Charge	—	—	—	—		—	—	—	—	
10	Delevan K3/Gerber - L401										
11	Reservation Charge	—	—	—	—		—	—	—	—	
12	Usage Charge	—	—	—	—		—	—	—	—	
13	Total Charge	—	—	—	—		—	—	—	—	
14	P03107 Topock, P-Units Replacement										
15	Reservation Charge	—	—	—	—	0.0269	—	—	—	—	0.0406
16	Usage Charge	—	—	—	—	0.0005	—	—	—	—	0.0000
17	Total Charge	—	—	—	—	0.0014	—	—	—	—	0.0014
18	P02158-Topock K-Units Replacement-Ph 1										
19	Reservation Charge	—	—	—	—		—	—	—	—	
20	Usage Charge	—	—	—	—		—	—	—	—	
21	Total Charge	—	—	—	—		—	—	—	—	
22	P02158-Topock K-Units Replacement-Ph 2										
23	Reservation Charge	—	—	—	—	0.0818	—	—	—	—	0.1235
24	Usage Charge	—	—	—	—	0.0015	—	—	—	—	0.0001
25	Total Charge	—	—	—	—	0.0041	—	—	—	—	0.0041
27	**Total Base Rates Plus Adders (1)**										
28	Reservation Charge	5.8930	6.0418	5.8953	5.9939		9.0536	9.2370	8.9457	9.0486	
29	Usage Charge	0.1129	0.1140	0.1090	0.1093		0.0089	0.0089	0.0087	0.0088	
30	Total Charge	0.3066	0.3126	0.3028	0.3063		0.3066	0.3126	0.3028	0.3063	

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

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Appendix A
Rates Effective January 1, 2014

Table A-4 (Continued)
Designated Local and BackboneTransmission Projects

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

G-XF: Pipeline Expansion Firm Intrastate Transportation Service

Line		Expansion Shippers (G-XF)			
		SFV			
No.		**2011 (2)**	**2012**	**2013 (3)**	**2014 (4)**
1	**Base Rates ($/Dth)**				
2	Reservation Charge	6.1394	6.2159	5.7146	5.5594
3	Usage Charge	0.0013	0.0015	0.0031	0.0035
4	Total Charge	0.2032	0.2059	0.1910	0.1863
5	**Adder Rates**				
6	Delevan K3/Gerber - L401				
7	Reservation Charge	----	----	----	----
8	Usage Charge	----	----	----	----
9	Total Charge	----	----	----	----
10	**Total Base Rates Plus Adders (1)**				
11	Reservation Charge	6.1394	6.2159	5.7146	5.5594
12	Usage Charge	0.0013	0.0015	0.0031	0.0035
13	Total Charge	0.2032	0.2059	0.1910	0.1863

(1) Total Base Rates Plus Adders are summarized in the rate tables presented in Appendix B.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Gas Accord V Settlement Agreement

Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-5

On-System Demand Forecast (Mdth/d)

Line No.	Service	2011	2012	2013	2014
1	Core	800	802	799	797
2	Industrial and Noncore NGV	468	473	472	472
3	Cogeneration	198	198	198	198
4	Power Plants and Miscellaneous EG				
5	Backbone Level Service	333	371	367	387
6	Local Transmission Level Service	188	231	259	251
7	Subtotal Power Plants and Miscellaneous EG	520	602	626	638
8	Wholesale	10	10	10	10
9	Total	1,996	2,085	2,106	2,115

Appendix A
(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-6
Billing Units for Cost Allocation

Line No.	Service	Annual Injection Storage Units	Inventory	Annual Withdrawal Storage Units
1	Core Firm Storage	41,074.4	33,477.7	178,601.0
2	Monthly Balancing Service	27,785.6	4,100.0	27,785.6
3	Market Storage (Traditional)	53,454.3	9,000.0	64,766.7
4	Market Storage (Gill Ranch)	17,180.6	3,150.0	22,668.3

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Appendix A

(No Change from August 20, 2010 Gas Accord V Settlement Filing)

Table A-7

Local Transmission Bill Credits and Funding Mechanism for Bill Credit Recovery

Line No.		GA IV 2010	2011	2012	2013	2014
1	Moss Landing Units 1 & 2 Local Transmission Bill Credit					
2	Annual, $000	$2,164	$2,500	$2,550	$2,601	$2,653
3	Monthly, $	$180,336	$208,333	$212,500	$216,750	$221,085
4	City of Redding Local Transmission Bill Credit					
5	Annual, $000	$52	$65	$66	$68	$69
6	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
7	Modesto Irrigation District Local Transmission Bill Credit					
8	Annual, $000	$52	$65	$66	$68	$69
9	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
10	Turlock Irrigation District Local Transmission Bill Credit					
11	Annual, $000	$52	$65	$66	$68	$69
12	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
13	City of Santa Clara (Silicon Valley Power) Local Transmission Bill Credit					
14	Annual, $000	$52	$65	$66	$68	$69
15	Monthly, $	$4,335	$5,417	$5,525	$5,636	$5,748
16	Total NCGC Local Transmission Billing Credit					
17	Annual, $000	$208	$260	$265	$271	$276
18	**Total Local Transmission Billling Credit**					
	Annual, $000	$2,372	$2,760	$2,815	$2,872	$2,929
19	Revenue Recovered Through Backbone Rates, $000					
20	Responsibility for Moss Landing 1&2, $000	$1,623	$1,800	$1,836	$1,873	$1,910
21	Backbone Annual AFT Surcharge Rate, $ per Dth	$0.0024	$0.0024	$0.0024	$0.0024	$0.0024
22	Backbone Seasonal SFT & As-Available AA Surcharge Rate, $ per Dth	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029
23	Revenue Recovered Through Backbone-Level End-Use G-NT and G-EG Rates, $000					
24	Responsibility for Moss Landing 1&2, $000	$541	$600	$612	$624	$637
25	Responsibility for NCGC, $000	$104	$130	$133	$135	$138
26	Total Revenue Responsibility	$645	$730	$745	$759	$775
27	Surcharge Rate, $ per Dth	$0.0053	$0.0065	$0.0067	$0.0068	$0.0069
28	Surcharge Rate, $ per Therm	$0.00053	$0.00065	$0.00067	$0.00068	$0.00069
29	**Total Revenue Responsibilty From Surcharges (a)**					
30	Annual, $000	$2,268	$2,530	$2,581	$2,632	$2,685
31	PG&E Shareholder Revenue Responsibility					
32	Moss Landing 1&2	$0	$100	$102	$104	$106
33	NCGC	$104	$130	$133	$135	$138
34	Total Shareholder Revenue Responsibility	$104	$230	$235	$239	$244

(a) PG&E is at risk for collecting the difference between the non-shareholder funded portion of the bill credit and the total revenue responsibility used to calculate the surcharge rates.

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Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2014

Table B-3

Firm Backbone Transportation
Annual Rates (AFT) -- SFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2014 or later)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path - Core (1)						
Reservation Charge	($/dth/mo)	4.3368	6.5162	6.4678	6.3001	6.3780
Usage Charge	($/dth)	0.0124	0.0102	0.0096	0.0091	0.0092
Total	($/dth @ Full Contract)	0.1550	0.2244	0.2223	0.2162	0.2188
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	9.2319	7.2499	7.3504	7.3313	7.5567
Usage Charge	($/dth)	0.0153	0.0111	0.0106	0.0102	0.0104
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2512	0.2588
Redwood Path - Noncore						
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.9034	7.8577
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0080
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.9457	9.0486
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0087	0.0088
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3063
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	4.4828	4.8056	4.6413	4.4150	4.4293
Usage Charge	($/dth)	0.0060	0.0049	0.0059	0.0077	0.0082
Total	($/dth @ Full Contract)	0.1534	0.1628	0.1585	0.1528	0.1538

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Appendix B

Rates Effective January 1, 2014

Table B-4

Firm Backbone Transportation
Annual Rates (AFT) -- MFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2014 or later)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital an GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path - Core (1)						
Reservation Charge	($/dth/mo)	3.3290	4.7466	4.6534	4.4923	4.5126
Usage Charge	($/dth)	0.0455	0.0684	0.0693	0.0685	0.0705
Total	($/dth @ Full Contract)	0.1549	0.2244	0.2223	0.2162	0.2188
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	7.0037	5.2811	5.2883	5.2276	5.3466
Usage Charge	($/dth)	0.0885	0.0758	0.0784	0.0794	0.0831
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2512	0.2588
Redwood Path - Noncore						
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.2084	5.2050
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0965	0.0952
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8953	5.9939
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1090	0.1093
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3063
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	3.0839	3.2679	3.1639	3.1425	3.1566
Usage Charge	($/dth)	0.0518	0.0554	0.0545	0.0495	0.0500
Total	($/dth @ Full Contract)	0.1532	0.1628	0.1585	0.1528	0.1538

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Appendix B

Rates Effective January 1, 2014

Table B-5

Firm Backbone Transportation
Seasonal Rates (SFT) -- SFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2014 or later)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital an GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path						
Reservation Charge	($/dth/mo)	10.4795	9.9714	10.0125	9.4840	9.4293
Usage Charge	($/dth)	0.0082	0.0101	0.0100	0.0095	0.0096
Total	($/dth @ Full Contract)	0.3527	0.3379	0.3392	0.3213	0.3196
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	11.0784	8.6999	8.8204	8.7976	9.0680
Usage Charge	($/dth)	0.0183	0.0133	0.0127	0.0122	0.0125
Total	($/dth @ Full Contract)	0.3825	0.2993	0.3027	0.3015	0.3106
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	11.0784	10.8643	11.0843	10.7348	10.8584
Usage Charge	($/dth)	0.0183	0.0107	0.0107	0.0104	0.0106
Total	($/dth @ Full Contract)	0.3825	0.3679	0.3752	0.3633	0.3676
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	5.3794	5.7667	5.5695	5.2980	5.3151
Usage Charge	($/dth)	0.0071	0.0058	0.0071	0.0092	0.0098
Total	($/dth @ Full Contract)	0.1840	0.1954	0.1902	0.1834	0.1846

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

g) Dollar difference are due to rounding.

A.09-09-013

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2014

Table B-6

Firm Backbone Transportation
Seasonal Rates (SFT) -- MFV Rate Design
On-System Transportation Service
(Topock Adder Projects In-Service 2014 or later)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital an GHG Compressor Cost

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)
Redwood Path						
Reservation Charge	($/dth/mo)	6.0840	6.4905	6.5491	6.2501	6.2460
Usage Charge	($/dth)	0.1528	0.1245	0.1238	0.1159	0.1142
Total	($/dth @ Full Contract)	0.3528	0.3379	0.3392	0.3213	0.3196
Baja Path - Core (1)						
Reservation Charge	($/dth/mo)	8.4044	6.3373	6.3460	6.2731	6.4159
Usage Charge	($/dth)	0.1063	0.0910	0.0941	0.0952	0.0997
Total	($/dth @ Full Contract)	0.3826	0.2993	0.3027	0.3015	0.3106
Baja Path - Noncore						
Reservation Charge	($/dth/mo)	8.4044	7.0717	7.2502	7.0744	7.1926
Usage Charge	($/dth)	0.1063	0.1354	0.1368	0.1308	0.1311
Total	($/dth @ Full Contract)	0.3826	0.3679	0.3752	0.3633	0.3676
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	3.7008	3.9215	3.7967	3.7710	3.7879
Usage Charge	($/dth)	0.0622	0.0665	0.0654	0.0594	0.0601
Total	($/dth @ Full Contract)	0.1839	0.1954	0.1902	0.1834	0.1846

(1) Rates apply to the core allocations of backbone transmission capacity designated in Table A-1: "Delivery Point Backbone Capacity Assignments/Options." These rates are closed to new customers.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

g) Dollar difference are due to rounding.

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2014

Table B-7

As-Available Backbone Transportation
On-System Transportation Service
(Topock Adder Projects In-Service 2014 or later)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		2010	GA IV	2011 (1)	2012	2013 (2)	2014 (3)
Redwood Path							
Usage Charge	($/dth)	0.3528		0.3379	0.3392	0.3213	0.3196
Baja Path							
Usage Charge	($/dth)	0.3826		0.3679	0.3752	0.3633	0.3676
Silverado Path							
Usage Charge	($/dth)	0.1839		0.1954	0.1902	0.1834	0.1846
Mission Path							
Usage Charge	($/dth)	0.0000		0.0000	0.0000	0.0000	0.0000

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) As-Available rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Appendix B

Rates Effective January 1, 2014

Table B-8

Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries
(Topock Adder Projects In-Service 2014 or later)

G-AFT: Annual Firm Transportation On-System

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
SFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.9034	7.8577
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0080
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663
Baja Path Off-System						
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.9457	9.0486
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0087	0.0088
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3063
MFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.2084	5.2050
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0965	0.0952
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663
Baja Path Off-System						
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8953	5.9939
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1090	0.1093
Total	($/dth @ Full	0.3188	0.3066	0.3126	0.3028	0.3063
As-Available Service						
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore						
Usage Charge	($/dth)	0.3528	0.3379	0.3392	0.3213	0.3196
Mission Paths (From on-system storage) Off-System						
Usage Charge	($/dth)	0.0000	0.0000	0.0000	0.0000	0.0000
Baja Path Off-System - Noncore						
Usage Charge	($/dth)	0.3826	0.3679	0.3752	0.3633	0.3676

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

d) Rates include Moss Landing Units 1 & 2 and NCGC local transmission bill credit surcharges of $0.0024 per Dth.

e) Dollar difference are due to rounding.

Appendix B

Rates Effective January 1, 2014

Table B-9

Firm Transportation
Expansion Shippers -- Annual Rates (G-XF)
SFV Rate Design

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GI Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
SFV Rate Design						
Reservation Charge	($/dth/mo)	6.3182	6.1394	6.2159	5.7146	5.5594
Usage Charge	($/dth)	0.0019	0.0013	0.0015	0.0031	0.0035
Total	($/dth @ Full Contract)	0.2096	0.2032	0.2059	0.1910	0.1863

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude any non-operational Backbone Transmission adder projects and exclude Local Transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.

d) Dollar difference are due to rounding.

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2014

Table B-10

Storage Services

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
Core Firm Storage (G-CFS)						
Reservation Charge	($/dth/mo)	0.1092	0.1293	0.1248	0.1232	0.1260
Standard Firm Storage (G-SFS)						
Reservation Charge	($/dth/mo)	0.1350	0.3008	0.2451	0.2374	0.2399
Negotiated Firm Storage (G-NFS)						
Injection	($/dth/d)	15.6336	6.1656	6.1542	5.9623	6.0252
Inventory	($/dth)	1.6205	2.9461	2.9407	2.8489	2.8790
Withdrawal	($/dth/d)	11.7865	21.3468	21.3075	20.6428	20.8607
Negotiated As-Available Storage (G-NAS) - Maximum Rate						
Injection	($/dth/d)	15.6336	6.1656	6.1542	5.9623	6.0252
Withdrawal	($/dth/d)	11.7865	21.3468	21.3075	20.6428	20.8607
Market Center Services (Parking and Lending Services)						
Maximum Daily Charge ($/Dth/d)		0.9702	1.1053	1.1136	1.0821	1.0986
Minimum Rate (per transaction)		$ 57.00	57.00	57.00	57.00	57.00

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Rates for storage services are based on the costs of storage injection, inventory and withdrawal.

b) Core Firm Storage (G-CFS) and Standard Firm Storage (G-SFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.

c) Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.

d) Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.

e) Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g. inventory, injection, or withdrawal). The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.

f) Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.

g) The maximum charge for parking and lending is based on the annual cost of cycling one Dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season.

h) Gas Storage shrinkage will be applied in-kind on storage injections.

i) Dollar difference are due to rounding.

Rates Effective January 1, 2014

Table B-11

Local Transmission Rates
($/dth)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010 (1)	2011 (2)	2012	2013 (3)	2014 (4)
Base Rates:						
Core Retail		0.3764	0.4118	0.4182	0.4074	0.4173
Noncore Retail and Wholesale		0.1628	0.2031	0.1933	0.1912	0.2043
Rate Adders:						
Core						
	L-304		0.0000	0.0013	0.0012	0.0012
	L-406	0.0115	0.0248	0.0185	0.0166	0.0160
	L-407 Phase 1		0.0000	0.0000	0.0151	0.0144
	L-407 Phase 2		0.0000	0.0000	0.0000	0.0142
	Total	0.0115	0.0248	0.0198	0.0330	0.0458
Noncore Retail & Wholesale						
	L-304		0.0000	0.0006	0.0006	0.0006
	L-406	0.0050	0.0108	0.0085	0.0078	0.0078
	L-407 Phase 1		0.0000	0.0000	0.0071	0.0071
	L-407 Phase 2		0.0000	0.0000	0.0000	0.0070
	Total	0.0050	0.0108	0.0091	0.0155	0.0224
Total Base plus Adder:						
Core Retail		0.3879	0.4367	0.4380	0.4404	0.4631
Noncore Retail and Wholesale		0.1678	0.2139	0.2024	0.2066	0.2267

(1) The 2010 Local Transmission rates was escalated 2 percent and also includes the 2011 L-406 adder rate adopted in Gas Accord IV.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(4) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) The Gas Accord IV adopted 2010 local transmission rate includes a base rate component plus a rate adder for 2 of 5 of the specific local transmission capital projects designated in Section 8.4 of the Gas Accord IV Settlement Agreement. (Core rate adder: Line 138 adder of $0.0173 per Dth + Line 108 adder of $0.0152 per Dth = $0.0325 per Dth) (Noncore rate adder: Line 138 adder of $0.0075 per Dth + Line 108 adder of $0.0066 per Dth = $0.0141 per Dth)

Appendix B

Rates Effective January 1, 2014

Table B-12

Customer Access Charges
($ per Month)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)
G-EG / G-NT ($/month)						
Transmission and Distribution						
	(Therms/Month)					
Tier 1	0 to 5,000	$61.85	$54.34	$58.41	$58.88	$60.90
Tier 2	5,001 to 10,000	$184.23	$161.87	$174.00	$175.40	$181.41
Tier 3	10,001 to 50,000	$342.89	$301.27	$323.85	$326.46	$337.64
Tier 4	50,001 to 200,000	$450.01	$395.39	$425.02	$428.44	$443.12
Tier 5	200,001 to 1,000,000	$652.92	$573.67	$616.67	$621.63	$642.93
Tier 6	1,000,001 and above	$5,538.45	$4,866.21	$5,230.96	$5,273.02	$5,453.67
Wholesale ($/month)						
Alpine		$333.28	$286.66	$310.56	$313.06	$323.79
Coalinga		$1,474.03	$1,267.85	$1,373.51	$1,384.55	$1,431.99
Island Energy		$998.71	$859.01	$930.61	$938.09	$970.23
Palo Alto		$4,914.73	$4,227.28	$4,579.59	$4,616.40	$4,774.56
West Coast Gas - Castle		$856.26	$736.49	$797.87	$804.28	$831.84
West Coast Gas - Mather		$782.50	$673.05	$729.14	$735.00	$760.18

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) The 2011-2014 CAC revenue requirements are established in this GT&S Rate Case proceeding. The rate design for the customer access charge may be addressed in PG&E's Biennial Cost Allocation Proceedings (BCAP).

Gas Accord V Settlement Agreement

Appendix B

Rates Effective January 1, 2014

Table B-13

Self Balancing Credit
$/dth

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital and GHG Compressor Cost

	GA IV 2010		2011 (1)	2012	2013 (2)	2014 (3)
Self Balancing Credit	($0.0096)	I	($0.0130)	($0.0131)	($0.0129)	($0.0132)

(1) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S rates in effect during May through December 2011 have reflected the 2011 Gas Accord V Settlement revenue requirement. The Gas Accord V Settlement revenue requirement relied on an estimate of various costs and allocations that were to be decided in PG&E's 2011 GRC. The 2011 GRC Decision (D.11-05-018) was issued on May 5, 2011, four days after the Gas Accord V Settlement was implemented. Accordingly, the difference in estimated and final costs associated with PG&E's 2011 GRC proceeding were accumulated in the Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) balancing account and included in Customer Class Charge rates in PG&E's 2012 Annual Gas Trueup (AGT) filing.

(2) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013.

(3) Consistent with Section 7.5 of the Gas Accord V Settlement, the GT&S revenue requirement has been adjusted to reflect PG&E's Cost of Capital Decision (D.12-12-034) issued 12/20/2012 and GHG Compressor Cost Decision (D.13-03-017) issued on 3/21/2013. 2014 Revenue Requirement may be further adjusted to reflect the results of PG&E's 2014 GRC decision.

Notes:

a) Storage balancing costs are bundled in backbone rates. Customers or Balancing agents who elect self balancing on a daily basis can opt out of PG&E's monthly balancing program and receive a self-balancing credit.

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
30972-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 12	30637-G
30973-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 13	30638-G
30974-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 14	30639-G
30975-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 15	30376-G
30976-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 16	30377-G
30977-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 17	30378-G
30978-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 18	30379-G
30979-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 19	30380-G
30980-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 20	30381-G
30981-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 2	30382-G
30982-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 3	30383-G
30983-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 4	30172-G*

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
30984-G	GAS SCHEDULE G-AA AS AVAILABLE TRANSPORTATION ON-SYSTEM Sheet 2	30652-G
30985-G	GAS SCHEDULE G-AAOFF AS-AVAILABLE TRANSPORTATION OFF-SYSTEM Sheet 2	30654-G
30986-G	GAS SCHEDULE G-AFT ANNUAL FIRM TRANSPORTATION ON-SYSTEM Sheet 2	30388-G
30987-G	GAS SCHEDULE G-AFTOFF ANNUAL FIRM TRANSPORTATION OFF-SYSTEM Sheet 2	30658-G
30988-G	GAS SCHEDULE G-BAL GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS Sheet 4	30177-G
30989-G*	GAS SCHEDULE G-CFS CORE FIRM STORAGE Sheet 1	30178-G
30990-G	GAS SCHEDULE G-EG GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION Sheet 1	30390-G
30991-G	GAS SCHEDULE G-LEND MARKET CENTER LENDING SERVICES Sheet 1	30659-G
30992-G	GAS SCHEDULE G-LNG EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE Sheet 1	30391-G
30993-G	GAS SCHEDULE G-NAS NEGOTIATED AS-AVAILABLE STORAGE SERVICE Sheet 1	30664-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
30994-G*	GAS SCHEDULE G-NFS NEGOTIATED FIRM STORAGE SERVICE Sheet 1	30665-G
30995-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 1	30184-G
30996-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 2	30392-G
30997-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 1	30186-G
30998-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 2	30393-G
30999-G	GAS SCHEDULE G-PARK MARKET CENTER PARKING SERVICES Sheet 1	30675-G
31000-G	GAS SCHEDULE G-SFS STANDARD FIRM STORAGE SERVICE Sheet 1	30676-G
31001-G	GAS SCHEDULE G-SFT SEASONAL FIRM TRANSPORTATION ON- SYSTEM ONLY Sheet 2	30679-G
31002-G	GAS SCHEDULE G-WSL GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS Sheet 1	30395-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
31003-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 1	30192-G
31004-G	GAS SCHEDULE G-XF PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE Sheet 2	30396-G
31005-G*	GAS TABLE OF CONTENTS Sheet 1	30968-G*
31006-G*	GAS TABLE OF CONTENTS Sheet 2	30969-G
31007-G	GAS TABLE OF CONTENTS Sheet 3	30970-G
31008-G	GAS TABLE OF CONTENTS Sheet 4	30971-G*

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 12

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* (Cont'd.)

NONCORE p. 1

	G-NT TRANSMISSION		G-NT—DISTRIBUTION SUMMER								
THERMS:			0-20,833		20,834-49,999		50,000-166,666		166,667-249,999***		
NCA – NONCORE	$0.00995	(I)	$0.00990	(I)	$0.00990	(I)	$0.00990	(I)	$0.00990	(I)	
NCA – DISTRIBUTION SUBACCOUNT	$0.00621	(I)	$0.13401	(I)	$0.08437	(I)	$0.07422	(I)	$0.06629	(I)	
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069		
CSI- SOLAR THERMAL PROGRAM	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	
CEE INCENTIVE	$0.00000		$0.00010	(I)	$0.00010	(I)	$0.00010	(I)	$0.00010	(I)	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	
											(D)
NCA - ARB AB32 COI	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	
NONCORE IMPLEMENTATION PLAN – LT	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	
NONCORE IMPLEMENTATION PLAN – BB	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	
TOTAL RATE	**0.05986**	(I)	**0.18771**	(I)	**0.13807**	(I)	**0.12792**	(I)	**0.11999**	(I)	

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts Expense (F&U)

** Refer to footnotes at end of Noncore Default Tariff Rate Components.

*** Rate components for G-NT Distribution over 249,999 therms are the same as G-NT Transmission.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 13

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* (Cont'd.) NONCORE p. 2

THERMS:	G-NT BACKBONE		G-NT—DISTRIBUTION WINTER 0-20,833		20,834-49,999		50,000-166,666		166,667-249,999***	
NCA – NONCORE	$0.01007	(I)	$0.00990	(I)	$0.00990	(I)	$0.00990	(I)	$0.00990	(I)
NCA – DISTRIBUTION SUBACCOUNT	$0.00000		$0.18194	(I)	$0.11492	(I)	$0.10123	(I)	$0.09053	(I)
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)
CEE INCENTIVE	$0.00000		$0.00010	(I)	$0.00010	(I)	$0.00010	(I)	$0.00010	(I)
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	$0.00069	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)
NCA - ARB AB32 COI	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)
NONCORE IMPLEMENTATION PLAN – LT	$0.00000		$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)
NONCORE IMPLEMENTATION PLAN - BB	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)
NONCORE IMPLEMENTATION PLAN - Storage	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)
TOTAL RATE	**0.01886**	(I)	**0.23564**	(I)	**0.16862**	(I)	**0.15493**	(I)	**0.14423**	(I)

(D)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts Expense (F&U)

** Refer to footnotes at end of Noncore Default Tariff Rate Components.

*** Rate components for G-NT Distribution over 249,999 therms are the same as G-NT Transmission

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 14

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* (Cont'd.)

NONCORE p. 3

	G-EG (2)**		G-EG BACKBONE	
NCA – NONCORE	$0.00998	(I)	$0.00998	(I)
NCA – DISTRIBUTION SUBACCOUNT	$0.00195	(I)	$0.00195	(I)
CPUC FEE	$0.00003		$0.00003	
CSI- SOLAR THERMAL PROGRAM	$0.00000		$0.00000	
CEE INCENTIVE	$0.00000		$0.00000	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	$0.02121	(I)	$0.00069	(I)
NCA - ARB AB32 COI	$0.00089	(R)	$0.00089	(R)
NONCORE IMPLEMENTATION PLAN – LT	$0.01439	(I)	$0.00000	
NONCORE IMPLEMENTATION PLAN – BB	$0.00492	(I)	$0.00492	(I)
NONCORE IMPLEMENTATION PLAN - Storage	$0.00048	(I)	$0.00048	(I)
TOTAL RATE	**0.05385**	(I)	**0.01894**	(I)

(D)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts Expense (F&U)

** Refer to footnotes at end of Noncore Default Tariff Rate Components.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 15

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* (Cont'd.) NONCORE p. 4

	G-WSL							
	Palo Alto-T		Coalinga-T		Island Energy-T		Alpine-T	
NCA – NONCORE	$0.00893	(I)	$0.00885	(I)	0.00897	(I)	0.00882	(I)
NCA – DISTRIBUTION SUBACCOUNT	$0.00000		$0.00000		0.00000		0.00000	
CPUC FEE**	$0.00000		$0.00000		0.00000		0.00000	
CSI- SOLAR THERMAL PROGRAM	$0.00000		$0.00000		0.00000		0.00000	
CEE INCENTIVE	$0.00000		$0.00000		0.00000		0.00000	
LOCAL TRANSMISSION (AT RISK)	$0.02121	(I)	$0.02121	(I)	0.02121	(I)	0.02121	(I)
								(D)
NONCORE IMPLEMENTATION PLAN – LT	$0.01439	(I)	$0.01439	(I)	0.01439	(I)	0.01439	(I)
NONCORE IMPLEMENTATION PLAN – BB	$0.00492	(I)	$0.00492	(I)	0.00492	(I)	0.00492	(I)
NONCORE IMPLEMENTATION PLAN – Storage	$0.00048	(I)	$0.00048	(I)	0.00048	(I)	0.00048	(I)
TOTAL RATE	**0.04993**	(I)	**0.04985**	(I)	**0.04997**	(I)	**0.04982**	(I)

* All tariff rate components on this sheet include an allowance for Franchise Fees only.

** The CPUC Fee does not apply to customers on Schedule G-WSL

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* (Cont'd.)

	G-WSL					
	West Coast Mather-T		West Coast Mather-D		West Coast Castle-D	
NCA – NONCORE	$0.00893	(I)	$0.00899	(I)	$0.00892	(I)
NCA – DISTRIBUTION SUBACCOUNT	$0.00000		$0.14920	(I)	$0.11264	(I)
CPUC FEE**	$0.00000		$0.00000		$0.00000	
CSI- SOLAR THERMAL PROGRAM	$0.00000		$0.00000		$0.00000	
CEE INCENTIVE	$0.00000		$0.00000		$0.00000	
LOCAL TRANSMISSION (AT RISK)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)
NONCORE IMPLEMENTATION PLAN – LT	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)
NONCORE IMPLEMENTATION PLAN – BB	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)
NONCORE IMPLEMENTATION PLAN – Storage	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)
TOTAL RATE	**0.04993**	(I)	**0.19919**	(I)	**0.16256**	(I)

(D)

* All tariff rate components on this sheet include an allowance for Franchise Fees only.

** The CPUC Fee does not apply to customers on Schedule G-WSL

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 17

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)* NONCORE p. 6

	G-NGV4 TRANSMISSION		G-NGV4—DISTRIBUTION SUMMER							
THERMS:			0- 20,833		20,834- 49,999		50,000- 166,666		166,667- 249,999	
NCA – NONCORE	$0.01007	(I)	$0.00990	(I)	$0.00990	(I)	$0.00990	(I)	$0.01007	(I)
NCA – DISTRIBUTION SUBACCOUNT	$0.00000		$0.13401	(I)	$0.08437	(I)	$0.07422	(I)	$0.06629	(I)
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)
CEE INCENTIVE	$0.00000		$0.00010	(I)	$0.00010	(I)	$0.00010	(I)	$0.00010	(I)
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)
NCA - ARB AB32 COI	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)
NONCORE IMPLEMENTATION PLAN – LT	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)
NONCORE IMPLEMENTATION PLAN – BB	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)
NONCORE IMPLEMENTATION PLAN – Storage	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)
TOTAL RATE	**0.05377**	(I)	**0.18771**	(I)	**0.13807**	(I)	**0.12792**	(I)	**0.11999**	(I)

(D)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts.

** Refer to footnotes at end of Noncore Default Tariff Rate Components.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 18

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)*

NONCORE p. 7

THERMS:	G-NGV4 BACKBONE		G—NGV4-DISTRIBUTION WINTER 0-20,833		20,834-49,999		50,000-166,666		166,667-249,999		
NCA – NONCORE	$0.01007	(I)	0.00990	(I)	$0.00990	(I)	$0.00990	(I)	$0.00990	(I)	
NCA – DISTRIBUTION SUBACCOUNT	$0.00000		0.18194	(I)	$0.11492	(I)	$0.10123	(I)	$0.09053	(I)	
CPUC FEE	$0.00069		0.00069		$0.00069		$0.00069		$0.00069		
CSI- SOLAR THERMAL PROGRAM	$0.00112	(R)	0.00112	(R)	$0.00112	(R)	$0.00112	(R)	$0.00112	(R)	
CEE INCENTIVE	$0.00000		0.00010	(I)	$0.00010	(I)	$0.00010	(I)	$0.00010	(I)	
LNGV BALANCING ACCOUNT											
LOCAL TRANSMISSION (AT RISK)	$0.00069	(I)	0.02121	(I)	$0.02121	(I)	$0.02121	(I)	$0.02121	(I)	
											(D)
NCA - ARB AB32 COI	$0.00089	(R)	0.00089	(R)	$0.00089	(R)	$0.00089	(R)	$0.00089	(R)	
NONCORE IMPLEMENTATION PLAN – LT	$0.00000		0.01439	(I)	$0.01439	(I)	$0.01439	(I)	$0.01439	(I)	
NONCORE IMPLEMENTATION PLAN – BB	$0.00492	(I)	0.00492	(I)	$0.00492	(I)	$0.00492	(I)	$0.00492	(I)	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00048	(I)	0.00048	(I)	$0.00048	(I)	$0.00048	(I)	$0.00048	(I)	
TOTAL RATE	**0.01886**	(I)	**0.23564**	(I)	**0.16862**	(I)	**0.15493**	(I)	**0.14423**	(I)	

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts.

** Refer to footnotes at end of Noncore Default Tariff Rate Components.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 19

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)* NONCORE p. 8

	G-LNG (1)*	
NCA – NONCORE	$0.00000	
NCA – DISTRIBUTION SUBACCOUNT	$0.00000	
CPUC Fee	$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00000	
CEE	$0.00000	
LNGV BALANCING ACCOUNT	$0.19164	(I)
LOCAL TRANSMISSION (AT RISK)	$0.00000	
NONCORE IMPLEMENTATION PLAN – LT	$0.00000	
NONCORE IMPLEMENTATION PLAN – BB	$0.00000	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00000	
TOTAL RATE	**0.19233**	**(I)**

(D)

* All tariff rate components on the sheet include an allowance for Franchise Fees and Uncollectible Accounts.

** Refer to footnotes at end of Noncore Default Tariff Rate Components.

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.)

MAINLINE EXTENSION RATES (1)

Core Schedules (2)	Mainline Extension Rate (Per Therm) (T)		Core Customer Charges (3) ADU (therms) (4)	Per Day
Schedule G-NR1	$0.23411	(R)	0 – 5.0	$0.27048
			5.1 to 16.0	$0.52106
			16.1 to 41.0	$0.95482
			41.1 to 123.0	$1.66489
			123.1 & Up	$2.14936
Schedule G-NR2	$0.09873	(R)	All Usage Levels	$4.95518
Schedule G-NGV1	$0.06402	(I)	All Usage Levels	$0.44121
Schedule G-NGV2	N/A		All Usage Levels	N/A

Noncore Schedules	Mainline Extension Rate (Per Therm) (T)		Noncore Customer Access Charges (5) Average Monthly Use (Therms)	Per Day	
Schedule G-NT					
Distribution	$0.09827	(R)	0 to 5,000	$2.00219	(I)
Local Transmission	$0.00638	(R)	5,001 to 10,000	$5.96416	(I)
Backbone	$0.00000		10,001 to 50,000	$11.10049	(I)
			50,001 to 200,000	$14.56833	(I)
Schedule G-EG			200,001 to 1,000,000	$21.13742	(I)
Distribution	$0.00200	(R)	1,000,001 and above	$179.29874	(I)
Local Transmission	$0.00200	(R)			
Backbone	$0.00200	(R)			
Schedule G-NGV4					
Distribution	$0.09827	(R)			
Local Transmission	$0.00000				
Backbone	$0.00000				

(1) Mainline Extension Rates are required to support calculation of distribution-based revenues described in Rule 15.
(2) For all residential schedules, see Rule 15 for extension allowances.
(3) The Core Customer Charge is in addition to the core Mainline Extension Rates specified above.
(4) The applicable Schedule G-NR1 Customer Charge is based on the customer's highest Average Daily Usage (ADU) determined from among the billing periods occurring within the last twelve (12) months, including the current billing period. PG&E calculates the ADU for each billing period by dividing the total usage by the number of days in the billing period.
(5) The Noncore Customer Access Charge is in addition to the noncore Mainline Extension Rates specified above.

(Continued)

GAS PRELIMINARY STATEMENT PART C

GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

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	
BASE REVENUES (incl. F&U) :						
Authorized GRC Distribution Base Revenue (1)					1,195,641	
Pension (2)					46,015 (R)	
Less: Other Operating Revenue					(22,922)	
Authorized Distribution Revenues in Rates	1,176,359 (R)	42,375 (R)			1,218,734 (R)	
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:						
G-10 Procurement-Related Employee Discount	(1,042) (R)				(1,042) (R)	
G-10 Procurement Discount Allocation	411 (I)	631 (I)			1,042 (I)	
						(D)
Core Brokerage Fee Credit	(6,583)				(6,583)	
Distribution Base Revenue with Adj. and Credits	1,169,145 (R)	43,006 (R)			1,212,151 (R)	
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):						
Transportation Balancing Accounts	132,406 (I)	42,407 (I)			174,813 (I)	
Self-Generation Incentive Program Revenue Requirement	2,569 (I)	3,911 (I)			6,480 (I)	
CPUC Fee	1,970	1,240			3,210	
SmartMeter™ Project	79,202				79,202	
Winter Gas Savings Plan (WGSP) – Transportation	0 (R)				0 (R)	
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,808 (I)	627 (I)			3,435 (I)	
CARE Discount included in PPP Funding Requirement	(108,850) (I)				(108,850) (I)	
CARE Discount not included in PPP Surcharge Rates	0				0	
Transportation Forecast Period Costs & Balancing Account Balances	110,105 (I)	48,185 (I)			158,290 (I)	
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):						
Local Transmission	135,339 (I)	76,861 (I)			212,200 (I)	
Customer Access Charge – Transmission		5,026 (I)			5,026 (I)	
Storage	48,236 (I)		34,344 (I)		82,580 (I)	
Carrying Cost on PG&E Working Gas in Storage	2,367 (I)		636 (I)		3,003 (I)	
Backbone Transmission/L-401	96,207 (I)	0	135,405 (I)		231,612 (I)	
Gas Accord Revenue Requirement	282,149 (I)	81,887 (I)	170,385 (I)		534,421 (I)	

(1) The CPUC has not issued a final decision for the 2014 GRC before the end of 2013. As a result, January 1 revenue requirements for GRC Distribution and SmartMeter are kept at the same level as the 2013 AGT amounts as a placeholder. The amount includes the authorized distribution base revenue and F&U approved in GRC D.11-05-018 and changes to PG&E's cost of capital authorized in D.12-12-034. (T)

(2) Pursuant to D.09-09-020, PG&E will maintain the annual contribution to the Company's retirement plan trust fund at the adopted 2013 amount.

(3) -The total 2014 SGIP revenue requirement (RRQ) was approved in D.11-12-030.
-Since the 2014 GRC decision (see note 1) has not been issued and the ongoing revenue requirements associated with the SmartMeter™ is included in the 2014 GRC forecast, the 2013 revenue requirements is used as a placeholder. This treatment was authorized by Res. E-4620 on December 19, 2013 for the 2014 Annual Electric True-up.
-The WGSP has ended, thus there are no costs shown in Line 24. However, an undercollected balance relating to the WGSP is included in 2014 rates.

(4) The Gas Accord V RRQ was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates. Some amounts include changes to PG&E's cost of capital authorized in D.12-12-034. The backbone transmission amounts include the implementation of the AB32-related gas compressor station costs (D.13-03-017). (T)

*Some numbers may not add precisely due to rounding.

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

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)				
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):					
Illustrative Gas Supply Portfolio				1,032,199 (I)	1,032,199 (I)
Interstate and Canadian Capacity				160,081 (R)	160,081 (R)
WGSP – Procurement – Residential				0 (R)	0 (R)
F&U (on items above and Procurement Account Balances Below)				15,560 (R)	15,560 (R)
Backbone Capacity (incl. F&U)	(65,974) (R)			65,974 (I)	0
Backbone Volumetric (incl. F&U)	(30,233) (R)			30,233 (I)	0
Storage (incl. F&U)	(48,236) (R)			48,236 (I)	0
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(2,367) (R)			2,367 (I)	0
Core Brokerage Fee (incl. F&U)				6,583	6,583
Procurement Account Balances				3,452 (I)	3,452 (I)
Illus. Core Procurement Revenue Requirement	(146,810) (R)			1,364,685 (R)	1,217,875 (R)
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**1,414,589** (I)	**173,078** (I)	**170,385** (I)	**1,364,685** (R)	**3,122,737** (I)
IMPLEMENTATION PLAN REVENUE REQUIREMENT (7)					
Implementation Plan – Local Transmission	85,881 (I)	48,735 (I)			134,616 (I)
Implementation Plan – Backbone	17,462 (I)	23,308 (I)			40,770 (I)
Implementation Plan – Storage	3,291 (I)	2,281 (I)			5,572 (I)
Total Implementation Plan	**106,634 (I)**	**74,324 (I)**			**180,958 (I)**
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):					
Energy Efficiency (EE)	66,657 (I)	7,420 (I)			74,077 (I)
Energy Savings Assistance (ESA)	61,173 (I)	6,809 (I)			67,982 (I)
Research, Demonstration and Development (RD&D)	6,846 (I)	3,854 (I)			10,700 (I)
CARE Administrative Expense	1,678 (I)	1,128 (I)			2,806 (I)
Statewide Marketing, Education & Outreach – EE Flex Alert	229 (N)	26 (N)			255 (N)
BOE and CPUC Administrative Cost	242 (I)	137 (I)			379 (I)
PPP Balancing Accounts	(2,706) (I)	(6,589) (I)			(9,295) (I)
CARE Discount Recovered from non-CARE customers	65,072 (R)	43,778 (R)			108,850 (R)
Total PPP Funding Requirement in Rates	**199,191** (I)	**56,563** (I)			**255,754** (I)
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**1,720,414** (I)	**303,965** (I)	**170,385** (I)	**1,364,685** (R)	**3,559,449** (I)

(5) The credits shown in the Core column represent the core portion of the Gas Accord 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 2014 PPP surcharge AL 3426-G; and includes ESA program funding adopted in D.12-08-044, EE program funding adopted in D.12-11-015, CARE annual administrative expense adopted in D.12-08-044, and excludes F&U per D.04-08-010. (T)

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030. (T)

(Continued)

GAS PRELIMINARY STATEMENT PART C
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.

Cost Category	Factor: Core	Factor: Noncore	Factor: Unbundled Storage and System Load Balancing	Factor: Total
Distribution Base Revenue Requirements	0.965231 (R)	0.034769 (I)		1.000000
Intervenor Compensation	0.965231 (R)	0.034769 (I)		1.000000
Other – Equal Distribution Based on All Transportation Volumes	0.394382 (R)	0.605618 (I)		1.000000
Carrying Cost on PG&E Working Gas in Storage	0.718750		0.281250	1.000000
ARB AB32 Cost of Implementation Fee	0.512858 (R)	0.487142 (I)		1.000000
TID – Almond Power Plant Cold Year January	0.646104 (N)	0.353896 (N)		1.000000 (N)

   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 SCHEDULE G-AA
AS AVAILABLE TRANSPORTATION ON-SYSTEM

RATES: The Customer shall pay a Usage Charge for each decatherm equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

1. Usage Charge:

Path:	Usage Rate (Per Dth)	
Redwood to On-System	$0.3196	(R)
Baja to On-System	$0.3676	(I)
Silverado to On-System	$0.1846	(I)
Mission to On-System	$0.0000	

2. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

CREDIT-WORTHINESS: Customer must meet the creditworthiness requirements specified in Rule 25.

SERVICE AGREEMENT AND TERM: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) is required for service on this schedule. The minimum term for service under the GTSA is one (1) year.

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

NOMINATIONS: Nominations are required for gas transported under this rate schedule. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

BALANCING: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

GAS SCHEDULE G-AAOFF
AS-AVAILABLE TRANSPORTATION OFF-SYSTEM

RATES: The Customer shall pay a Usage Charge for each decatherm equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

1. Usage Charge:

Path:	Usage Rate (Per Dth)	
Redwood to Off-System	$0.3196	(R)
Baja to Off-System	$0.3676	(I)
Silverado to Off-System	$0.3196	(R)
Mission to Off-System	$0.3196	(R)
Mission to Off-System Storage Withdrawals	$0.0000	

2. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

NEGOTIABLE RATES: Rates under this schedule are not negotiable.

STORAGE WITHDRAWAL OPTIONS (MISSION TO OFF-SYSTEM): Storage withdrawals to PG&E's Backbone Transmission System may be nominated for off-system delivery under the Mission Off-System As-Available service for no additional charge.

CREDIT-WORTHINESS: Customer must meet the creditworthiness requirements specified in Rule 25.

SERVICE AGREEMENT: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) is required for service under this schedule. The minimum term for service under the GTSA is one (1) year.

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

NOMINATIONS: Nominations are required for gas transported under this rate schedule. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

BALANCING: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

GAS SCHEDULE G-AFT

Sheet 2

ANNUAL FIRM TRANSPORTATION ON-SYSTEM

RATES: Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will then be specified in the exhibits to the Customer's GTSA.

1. Reservation Charge:

The Reservation Charge shall be the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the exhibits to the Customer's GTSA. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

Path:	Reservation Rate (Per Dth per month)			
	MFV Rates		SFV Rates	
Redwood to On-System	$5.2050	(R)	$7.8577	(R)
Redwood to On-System (Core Procurement Groups only)	$4.5126	(I)	$6.3780	(I)
Baja to On-System	$5.9939	(I)	$9.0486	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$5.3466	(I)	$7.5567	(I)
Silverado to On-System (including Core Procurement Groups)	$3.1566	(I)	$4.4293	(I)
Mission to On-System (including Core Procurement Groups)	$3.1566	(I)	$4.4293	(I)

2. Usage Charge:

The Usage Charge shall be equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Path:	Usage Rate (Per Dth)			
	MFV Rates		SFV Rates	
Redwood to On-System	$0.0952	(R)	$0.0080	(I)
Redwood to On-System (Core Procurement Groups only)	$0.0705	(I)	$0.0092	(I)
Baja to On-System	$0.1093	(I)	$0.0088	(I)
Baja to On-System (N) (Core procurement Groups only) (N)	$0.0831	(I)	$0.0104	(I)
Silverado to On-System (including Core Procurement Groups)	$0.0500	(I)	$0.0082	(I)
Mission to On-System (including Core Procurement Groups)	$0.0500	(I)	$0.0082	(I)
Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only)	$0.0000		$0.0000	

(Continued)

GAS SCHEDULE G-AFTOFF
ANNUAL FIRM TRANSPORTATION OFF-SYSTEM

Sheet 2

RATES: Customer has the option to elect either the MFV or the SFV rate structure, which will then be specified in the exhibits to the Customer's GTSA.

1. Reservation Charge:

   The Reservation Charge shall be the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the exhibits to the Customer's GTSA. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

Path:	Reservation Rate (Per Dth per month)			
	MFV Rates		SFV Rates	
Redwood to Off-System	$5.2050	(R)	$7.8577	(R)
Baja to Off-System	$5.9939	(I)	$9.0486	(I)
Silverado to Off-System	$5.2050	(R)	$7.8577	(R)
Mission to Off-System	$5.2050	(R)	$7.8577	(R)

2. Usage Charge:

   The Usage Charge shall be equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Path:	Usage Rate (Per Dth)			
	MFV Rates		SFV Rates	
Redwood to Off-System	$0.0952	(R)	0.0080	(I)
Baja to Off-System	$0.1093	(I)	0.0088	(I)
Silverado to Off-System	$0.0952	(R)	0.0080	(I)
Mission to Off-System	$0.0952	(R)	0.0080	(I)

3. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

(Continued)

GAS SCHEDULE G-BAL

GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS

MONTHLY BALANCING OPTIONS: (Cont'd.)

CASHOUT FOR MONTHLY BALANCING:

Monthly imbalances after trading is completed, which exceed the Monthly Tolerance Band are cashed out for both the commodity component and the transportation component.

The Commodity Cashout for each month is based on the following four (4) imbalance categories: Over-deliveries and under-deliveries in the imbalance range of greater than five percent (5%) and less than or equal to ten percent (10%) of usage (Tier I Cashout), and over-deliveries and under-deliveries in the imbalance range of greater than ten percent (10%) of usage (Tier II Cashout). The amount of gas in each category is multiplied by the appropriate price as determined below to calculate the commodity cashout portion of the bill.

The Transportation Cashout for each month is based only on the under or over-delivery greater than five percent (5%). This amount is multiplied by the appropriate transportation cashout price as determined below to calculate the transportation cashout portion of the bill. In the case of an overdelivery, this will be a credit.

SELF-BALANCING OPTION:

The Self-Balancing option requires daily balancing within specified limits. To participate in Self-Balancing, the Balancing Agent must have an NBAA or CTA Group.

To elect Self-Balancing, the Balancing Agent must sign a Self-Balancing Amendment (Form No. 79-971) and the NBAA or the Core Gas Aggregation Service Agreement (CTA Agreement) will be subject to the terms of Self-Balancing for the period identified in the Amendment.

SELF-BALANCING CREDIT:

The Self-Balancing option allows a Balancing Agent to receive a credit. The Self-Balancing credit is $0.0132 (I) per Decatherm multiplied by the actual recorded monthly usage. Credits will be provided to the Balancing Agent on a monthly basis, subject to adjustments.

LIMIT ON SELF-BALANCING PARTICIPATION:

When a Balancing Agent elects Self-Balancing, their share of the balancing storage assets will be assigned to and marketed through PG&E's at-risk unbundled storage program. The amount of storage assets allocated to PG&E's at-risk unbundled storage program is based on the Balancing Agent's End-Use Customer's annual average usage as a percentage of PG&E's average annual system usage. PG&E will allow the election of Self-Balancing until the storage balancing assets of 1.1 Bcf of inventory, 25 MMcf per day of injection and 35 MMcf per day of withdrawal are reached. If these limits are reached, PG&E will restrict further elections for Self-Balancing until capacity is made available or the OFO Forum raises the limits.

(Continued)

GAS SCHEDULE G-CFS
CORE FIRM STORAGE

APPLICABILITY: This rate schedule* provides the rates and charges associated with core firm storage capacity (Allocated Storage) allocated to Core Transport Agents (CTAs) and PG&E's Core Gas Supply Department (CGS), pursuant to the core firm storage provisions of Schedule G-CT.

This schedule also provides the methodology for determining the quantity of gas inventory that may be sold to or purchased from a CTA by CGS, as amounts of Allocated Storage change during the Storage Year. In addition, this schedule describes the calculation of the prices to be paid when such gas inventory is transferred.

CTAs and CGS may also take storage service under Schedule(s), G-SFS, G-NFS and/or G-NAS in conjunction with service under this rate schedule.

TERRITORY: Schedule G-CFS applies to the firm use of PG&E's storage facilities.

ALLOCATED STORAGE MONTHLY CHARGE: CTAs and CGS holding an allocation of core firm storage (Allocated Storage), pursuant to the provisions of Schedule G-CT, will be billed each month based upon the amount of Allocated Storage held for all or a portion of the current month. The monthly charge is calculated by multiplying the applicable monthly rate, shown below, by the inventory quantity associated with the CTA's and CGS' Allocated Storage for that month subject to proration in the event of an assignment of Allocated Storage during the current month.

Reservation Charge per Dth per month	$0.1260 (I)

SHRINKAGE: In-kind storage shrinkage is applicable to all injection quantities in accordance with gas Rule 21.

SERVICE AGREEMENT: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) and applicable exhibit(s) and an Electronic Commerce System User Agreement (Form No. 79-982) are required for CTAs and CGS taking service under this Rate Schedule.

TERM: Core firm storage is allocated for a one-year term starting on April 1 and ending on March 31 of the following year (Storage Year), and may be assigned by CTA and CGS under the provisions of Assignment Of Allocated Storage, specified below.

NOMINATIONS: Nominations are required for injections and withdrawals. See Rule 21 for details.

INJECTION/ WITHDRAWAL: This schedule provides for firm injection and withdrawal for CTAs and CGS. It also specifies month-end minimum inventory targets for CTAs and CGS.

Firm injection is available from April 1 through October 31. Firm withdrawal is available from November 1 through March 31. In addition, firm summer withdrawal and winter injection are also available, as specified below.

Injection and Withdrawal Capacities

For CTAs and CGS that hold up to 1,000,000 Dth of Annual Inventory (AI), fixed injection and withdrawal capacities are allocated pursuant to Schedule G-CT.

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-EG

Sheet 1

GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION

APPLICABILITY: This rate schedule* applies to the transportation of natural gas used in: (a) electric generation plants served directly from PG&E gas facilities that have a maximum operation pressure greater than sixty pounds per square inch (60 psi); (b) all Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 216.6**; (c) solar electric generation plants, defined herein and (d) Advanced Electrical Distributed Generation technology that meets all of the conditions specified in Public Utilities Code Section 379.8, as defined in Rule 1, and are first operational at a site prior to January 1, 2014. This schedule does not apply to gas transported to non-electric generation loads.

Customers on Schedule G-EG permanently classified as Noncore End-Use Customers, per Rule 1 must procure gas supply from a third-party gas supplier, not from a Core Procurement Group, as defined in Rule 1.

Certain noncore customers served under this rate schedule may be restricted from converting to a core rate schedule. See Rule 12 for details on core and noncore reclassification.

TERRITORY: Schedule G-EG applies everywhere within PG&E's natural gas Service Territory.

RATES: The following charges apply to this schedule. They do not include charges for service on PG&E's Backbone Transmission System:

1. Customer Access Charge:

   The applicable Per-Day Customer Access Charge specified below is based on the Customer's Average Monthly Use, as defined in Rule 1. Usage through multiple noncore meters on a single premises will be combined to determine Average Monthly Usage. Customers taking service under this schedule who also receive service under other noncore rate schedules at the same premises will be charged a single Customer Access Charge under this schedule.

Average Monthly Use (Therms)	Per Day	
0 to 5,000 therms	$2.00219	(I)
5,001 to 10,000 therms	$5.96416	(I)
10,001 to 50,000 therms	$11.10049	(I)
50,001 to 200,000 therms	$14.56833	(I)
200,001 to 1,000,000 therms	$21.13742	(I)
1,000,001 and above therms	$179.29874	(I)

2. Transportation Charge:

   Customers will pay one of the following rates for gas delivered in the current billing period:

   a. The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

      Backbone Level Rate: $0.01894 per therm (I)

   b. All Other Customers: $0.05385 per therm (I)

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* PG&E's gas tariffs are available on-line at www.pge.com.

** Efficiency Standard: In accordance with PU Code Section 216.6, at least 5 percent of the facility's total output must be in the form of useful thermal energy. Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output must equal no less than 42.5 percent of any natural gas and oil energy input.

Note: Customers who are directly billed by Air Resources Board (ARB) for ARB AB32 Administration Fees are exempt from PG&E's ARB AB32 Cost of Implementation (COI) rate component. Customers on the Directly Billed list, as provided annually by the ARB, may change from year to year. The exemption credit will be equal to PG&E's currently-effective ARB AB32 COI per-therm rate component (as shown in PG&E's Preliminary Statement, Part B – "Default Tariff Rate Components"), times the customer's billed volumes (therms) for each billing period.

(Continued)

GAS SCHEDULE G-LEND
MARKET CENTER LENDING SERVICES

APPLICABILITY: This rate schedule* applies to the gas lending service offered to Customers as part of PG&E's Golden Gate Market Center Services. Gas lending is the temporary loan of gas from the PG&E gas transmission system. This service is provided on an interruptible basis only, and is the lowest priority transmission service offered by PG&E.

The Customer shall be responsible for arranging and paying for interstate and Backbone transportation service, as applicable, for transportation into and out of their Market Center accounts.

TERRITORY: The points of service for lending under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Rates will be negotiated on a transaction-by-transaction basis and shall be within the range set forth below:

Minimum Rate (per transaction): $57.00

Maximum Rate (per Dth per day): .... $1.0986 (I)

The minimum rate reflects PG&E's minimum costs to offer and operate the service.

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements specified in Rule 25.

SERVICE AGREEMENT: Service under this schedule is available to Customers who have executed a Gas Transmission Service Agreement (GTSA) (Form No. 79-866) with PG&E.

NOMINATIONS: Notice is required for service under this schedule, as agreed to by PG&E and the customer.

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-LNG
EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE

Sheet 1

APPLICABILITY: This rate schedule* applies to experimental natural gas liquefaction service provided by PG&E to noncore End-Use Customers. This experimental liquefaction service is limited and PG&E will provide this service on a first-come first-served basis.

TERRITORY: Schedule G-LNG applies to the PG&E experimental Liquefied Natural Gas (LNG) facility located in Sacramento, California.

RATES: The following charges will apply to per therm liquefied natural gas service under this rate schedule:

Liquefaction Charge (Per Therm): $0.19233 (I)

LNG Gallon Equivalent: $0.15771 (I)
(Conversion factor - One LNG Gallon = 0.82 Therms)

Public Purpose Program Surcharge:
Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

METERING: For metering and billing purposes, the number of LNG gallons dispensed will be compiled from a summary of transactions recorded at the dispensing unit for the Customer during a calendar month. Delivery and custody transfer of LNG shall be at the point where LNG is dispensed into the Customer's LNG transport vehicle. LNG will be weighed and converted to LNG gallons. Vehicles must be weighed at an authorized weigh station prior to receiving LNG and again after filling. Weight information must be provided to PG&E within 5 business days. LNG gallons delivered will be converted to therms and billed. LNG usage that occurs during a billing period, but which is not recorded in that billing period, will be deferred to a future billing period.

The rate includes local transportation costs from the PG&E Citygate to the LNG Facility. These charges do not include transportation service on PG&E's Backbone Transmission System, which must be arranged for separately

See Preliminary Statement, Part B for the default tariff rate components.

LNG COMPOSITION: The resulting LNG product delivered will contain amounts equal to or greater than ninety-six percent (96%) methane and amounts equal to or less than four percent (4%) ethane.

SERVICE AGREEMENT: The Customer must execute a Natural Gas Service Agreement (NGSA) Form No. 79-756 to receive service under this schedule.

NOMINATIONS: Customers who take service under this schedule must arrange for the delivery of natural gas to the PG&E LNG facility in quantities necessary to equal the amount of LNG fuel dispensed to the customer. Nominations are required for gas transported under this schedule. See Rule 21 for details.

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* PG&E's gas tariffs are on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NAS
NEGOTIATED AS-AVAILABLE STORAGE SERVICE

APPLICABILITY: This rate schedule* applies to the As-available use of PG&E's storage facilities. Storage injection and withdrawal may be taken separately under this schedule. Core Transport Agents, or PG&E, on behalf of Core Customers, may take storage service in excess of that provided by the core storage allocation.

TERRITORY: The rate schedule applies to use of PG&E's storage facilities. The points of service for storage under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Customers taking service under this rate schedule will pay monthly Usage Charges for any injection and/or withdrawal services utilized during the billing period. Any injections and/or withdrawals occurring during a billing period, but not recorded in that billing period, shall be deferred to a future billing period.

Negotiated rates for service under this rate schedule shall not be less than PG&E's marginal cost of providing the service and shall not exceed a price which will collect 100 percent of PG&E's total revenue requirement for the Unbundled Storage Program under both subfunctions (e.g., injection or withdrawal), as shown below. Customers will be billed on a monthly basis.

	Maximum Rates (Per Dth/Day)
Injection	$6.0252 (I)
Withdrawal	$20.8607 (I)

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

SHRINKAGE: In-kind storage shrinkage is available to all injection quantities in accordance with gas Rule 21.

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements as specified in Rule 25.*

SERVICE AGREEMENT: A Gas Transmission Service Agreement (GTSA) (Form No. 79-866) and storage exhibit thereto are required for service under this rate schedule.

NOMINATIONS: Notice is required for injections and withdrawals as agreed to by PG&E and the customer. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

* PG&E's gas tariffs are available on-line at www.pge.com.

GAS SCHEDULE G-NFS
NEGOTIATED FIRM STORAGE SERVICE

APPLICABILITY: This rate schedule* applies to the firm use of PG&E’s storage facilities, subject to rates negotiated by the Customer and PG&E. Fixed amounts of firm storage inventory, injection, and withdrawal service may be procured separately or in combination under this rate schedule. Core Transport Agents and PG&E, on behalf of Core Customers, may take storage service under this rate schedule for storage in excess of that provided by their core firm storage allocation.

TERRITORY: This rate schedule applies to firm use of PG&E's storage facilities. The points of service for storage under this schedule are the various locations at which PG&E’s system interconnects with interstate pipelines, at Kern River Station, and at PG&E’s Citygate.

RATES: Rates under this schedule are negotiable and may be structured as one-part rates (Usage or Reservation Charge) or two-part rates (both Reservation and Usage Charges), as negotiated between the Customer and PG&E. Reservation Charges, if applicable, shall be based on the injection, inventory, and/or withdrawal quantities specified in the Exhibit E to the Gas Transmission Service Agreement (GTSA) (Form 79-866-E). Any Usage Charges shall be equal to the applicable effective rate in the GTSA multiplied by the actual injection, inventory, or withdrawal quantities occurring during that billing period, including volumes traded pursuant to Schedule G-BAL. Any injections and withdrawals which occur during a billing period, but which are not recorded in that billing period, will be deferred to a future billing period.

Negotiated rates, for service under this schedule, are subject to minimum and maximum rates. Negotiated rates for storage service shall not be less than PG&E’s marginal cost of providing the service. Negotiated rates for storage service will be capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three (3) subfunctions (i.e., injection, inventory or withdrawal), as listed below.

	Maximum Rates (Dth)	
Injection/Day	$6.0252	(I)
Inventory	$2.8790	(I)
Withdrawal/Day	$20.8607	(I)

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

* PG&E’S gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NGV4

Sheet 1

NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

APPLICABILITY: This rate schedule* applies to the transportation of gas to customer-owned natural gas vehicle fueling stations on PG&E's Backbone, Local Transmission and/or Distribution Systems. To qualify for service under this schedule, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential Customer must have maintained an average monthly use, through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. See Rule 12 for details on core and noncore reclassification.

Customers must procure gas supply from a supplier other than PG&E.

TERRITORY: Schedule G-NGV4 applies everywhere within PG&E's natural gas Service Territory.

RATES: The applicable Customer Access Charges and Distribution Level Transportation Rate specified below is based on the Customer's Average Monthly Usage, as defined in Rule 1. Usage through multiple noncore gas meters on a single premises will be combined to determine Average Monthly Usage.

The following charges apply to service under this schedule:

1. Customer Access Charge:

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

Average Monthly Use (Therms)	Per Day	
0 to 5,000	$2.00219	(I)
5,001 to 10,000	$5.96416	(I)
10,001 to 50,000	$11.10049	(I)
50,001 to 200,000	$14.56833	(I)
200,001 to 1,000,000	$21.13742	(I)
1,000,001 and above	$179.29874	(I)

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NGV4

NONCORE NATURAL GAS SERVICE
FOR COMPRESSION ON CUSTOMERS' PREMISES

RATES: (Cont'd.)

2. Transportation Charge:

A customer will pay one of the following rates for gas delivered in the current billing month.

a. Backbone Level Rate:

The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

Backbone Level Rate (per therm) .... $0.01886 (I)

b. Transmission-Level Rate:

The Transmission-Level Rate applies to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi) that do not qualify for the Backbone Level Rate.

Transmission-Level Rate (per therm)............................... $0.05377 (I)

c. Distribution-Level Rate:

The Distribution-Level Rate applies to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate specified above.

Average Monthly Use (Therms)	Summer (Per Therm)		Winter (Per Therm)	
Tier 1: 0 to 20,833	$0.18771	(I)	$0.23564	(I)
Tier 2: 20,834 to 49,999	$0.13807	(I)	$0.16862	(I)
Tier 3: 50,000 to 166,666	$0.12792	(I)	$0.15493	(I)
Tier 4: 166,667 to 249,999	$0.11999	(I)	$0.14423	(I)
Tier 5: 250,000 and above*	$0.05377	(I)	$0.05377	(I)

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES FEES AND TAXES:

Customer may pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details.) The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

Public Purpose Program Surcharge:
Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

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* Tier 5 Summer and Winter rates are the same.

(Continued)

GAS SCHEDULE G-NT

Sheet 1

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

APPLICABILITY: This rate schedule* applies to the transportation of natural gas to Noncore End-Use Customers on PG&E's Backbone, Local Transmission and/or Distribution Systems. To qualify for service under this schedule, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential Customer must have maintained an average monthly use, through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. Certain noncore customers served under this schedule may be restricted from converting to a core rate schedule. See Rule 12 for details on core and noncore reclassification.

Customers on Schedule G-NT must procure gas supply from a supplier other than PG&E.

TERRITORY: Schedule G-NT applies everywhere within PG&E's natural gas Service Territory.

RATES: The applicable Customer Access Charges and Distribution Level Transportation Rate specified below is based on the Customer's Average Monthly Usage, as defined in Gas Rule 1. Usage through multiple noncore gas meters on a single premises will be combined to determine Average Monthly Usage.

1. Customer Access Charge:

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

Average Monthly Use (Therms)	Per Day	
0 to 5,000	$2.00219	(I)
5,001 to 10,000	$5.96416	(I)
10,001 to 50,000	$11.10049	(I)
50,001 to 200,000	$14.56833	(I)
200,001 to 1,000,000	$21.13742	(I)
1,000,001 and above	$179.29874	(I)

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-NT
Sheet 2

GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS

RATES: (Cont'd.)

2. Transportation Charge:

A customer will pay one of the following rates for gas delivered in the current billing month.

a. Backbone Level Rate:

The Backbone Level Rate applies to Backbone Level End-Use Customers as defined in Rule 1.

Backbone Level Rate (per therm): $0.01886 (I)

b. Transmission-Level Rate:

The Transmission-Level Rate applies to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi) that do not qualify for the Backbone Level Rate.

Transmission-Level Rate (per therm): $0.05986 (I)

c. Distribution-Level Rate:

The Distribution-Level Rate applies to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate specified above.

Average Monthly Use (Therms)	Summer (Per Therm)		Winter (Per Therm)	
Tier 1: 0 to 20,833	$0.18771	(I)	$0.23564	(I)
Tier 2: 20,834 to 49,999	$0.13807	(I)	$0.16862	(I)
Tier 3: 50,000 to 166,666	$0.12792	(I)	$0.15493	(I)
Tier 4: 166,667 to 249,999	$0.11999	(I)	$0.14423	(I)
Tier 5: 250,000 and above*	$0.05986	(I)	$0.05986	(I)

See Preliminary Statement Part B for Default Tariff Rate Components.

SURCHARGES, FEES AND TAXES:

Customer may pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details.) The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

* Tier 5 Summer and Winter rates are the same.

Note: Customers who are directly billed by Air Resources Board (ARB) for ARB AB32 Administration Fees are exempt from PG&E's ARB AB32 Cost of Implementation (COI) rate component. Customers on the Directly Billed list, as provided annually by the ARB, may change from year to year. The exemption credit will be equal to PG&E's currently-effective ARB AB32 COI per-therm rate component (as shown in PG&E's Preliminary Statement, Part B – "Default Tariff Rate Components"), times the customer's billed volumes (therms) for each billing period.

(Continued)

GAS SCHEDULE G-PARK

MARKET CENTER PARKING SERVICES

APPLICABILITY: This rate schedule applies to the gas parking service offered to Customers as part of PG&E's Golden Gate Market Center Services. Gas parking is the temporary storage of gas on the PG&E gas transmission system. This service is provided on an interruptible basis only, and is the lowest priority transmission service offered by PG&E.

The Customer shall be responsible for arranging and paying for interstate and Backbone transportation service, as applicable, for transportation into and out of their Market Center accounts.

TERRITORY: The points of service for parking under this schedule are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River Station, and at PG&E's Citygate.

RATES: Rates will be negotiated on a transaction-by-transaction basis and shall be within the range set forth below:

Minimum Rate (per transaction): $57.00

Maximum Rate (per Dth per day): .... $1.0986 (I)

The minimum rate reflects PG&E's minimum costs to offer and operate the service.

The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements specified in Rule 25.*

SERVICE AGREEMENT: Service under this schedule is available to Customers who have executed a Gas Transmission Service Agreement (GTSA) (Form No. 79-866) with PG&E.

NOMINATIONS: Notice is required for service under this schedule, as agreed to by PG&E and the customer.

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-SFS

STANDARD FIRM STORAGE SERVICE

Sheet 1

APPLICABILITY: This rate schedule* applies to the firm use of PG&E's storage facilities. This rate schedule provides a combination of firm storage injection, inventory and withdrawal service. Service under this rate schedule is available to any Customer including Core Procurement Groups (CPGs) on behalf of Core Customers for storage service in addition to that provided under Schedule G-CFS.

TERRITORY: This rate schedule applies to firm use of PG&E's storage facilities.

RATES: Rates under this schedule consist of Reservation Charges. The Reservation Charge is based upon the amount of inventory capacity held by the Customer (Contract Inventory). Contract Inventory is shown per Decatherm (Dth).

1. Reservation Charges:

   The Reservation Charges shall be based on the quantities specified in Exhibit J of the Customer's Gas Transmission Service Agreement (GTSA) (Form No. 79-866). The Reservation Charge includes inventory, injection and withdrawal rights. The monthly charge is calculated by multiplying the applicable monthly rate shown below by the inventory specified in the GTSA (Contract Inventory).

   Reservation Charge per Dth of Contract Inventory per month.......... $0.2399 (I)

2. Additional Charges:

   The Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

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* PG&E's gas tariffs are available on-line at www.pge.com

(Continued)

GAS SCHEDULE G-SFT

Sheet 2

SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY

RATES: Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will then be specified in the Customer's GTSA.

1. Reservation Charge:

   The Reservation Charge shall be the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the Exhibit to the Customer's GTSA. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

Path:	Reservation Rate (Per Dth per month)			
	MFV Rates		SFV Rates	
Redwood to On-System	$6.2460	(R)	$9.4293	(R)
Baja to On-System	$7.1926	(I)	$10.8584	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$6.4159	(I)	$9.0680	(I)
Silverado to On-System	$3.7879	(I)	$5.3151	(I)
Mission to On-System	$3.7879	(I)	$5.3151	(I)

2. Usage Charge:

   The Usage Charge shall be equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Path:	Usage Rate (Per Dth)			
	MFV Rates		SFV Rates	
Redwood to On-System	$0.1142	(R)	$0.0096	(I)
Baja to On-System	$0.1311	(I)	$0.0106	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$0.0997	(I)	$0.0125	(I)
Silverado to On-System	$0.0601	(I)	$0.0098	(I)
Mission to On-System	$0.0601	(I)	$0.0098	(I)

3. Additional Charges:

   The Customer shall be responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from Backbone or interstate sources.

(Continued)

GAS SCHEDULE G-WSL Sheet 1

GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS

APPLICABILITY: This rate schedule* applies to the transportation of natural gas for resale. Service under this schedule is available to the Customers listed below, and any new wholesale Customer. Customers must procure gas supply from a supplier other than PG&E.

LOAD FORECAST: For planning purposes, Customers may provide PG&E an annual forecast of the core and noncore portion of its load. If the Customer elects not to provide an annual forecast, PG&E will use the forecast adopted in the most recent Cost Allocation Proceeding.

RATES: Customers pay a Customer Access Charge and a Transportation Charge.

1. Customer Access Charge:

	Per Day	
Palo Alto	$156.97184	(I)
Coalinga	$47.07912	(I)
West Coast Gas-Mather	$24.99222	(I)
Island Energy	$31.89797	(I)
Alpine Natural Gas	$10.64515	(I)
West Coast Gas-Castle	$27.34816	(I)

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto-T	$0.04993	(I)
Coalinga-T	$0.04985	(I)
West Coast Gas-Mather-T	$0.04993	(I)
West Coast-Mather-D	$0.19919	(I)
Island Energy-T	$0.04997	(I)
Alpine Natural Gas-T	$0.04982	(I)
West Coast Gas-Castle-D	$0.16256	(I)

* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-XF

Sheet 1

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

APPLICABILITY: This rate schedule* is available to any Customer who holds a Pipeline Expansion Firm Transportation Service Agreement (FTSA) (Form No. 79-791) approved by the CPUC. This schedule is closed to new Customers. This schedule may also be taken in conjunction with Schedule G-STOR, G-FS, G-NFS, G-NAS, G-PARK, or G-LEND.

TERRITORY: Schedule G-XF applies to pre-existing Pipeline Expansion firm transportation service.

RATES: The following charges apply to intrastate natural gas transportation service under this schedule. In addition, Customer will be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from inter- or intrastate sources and any other applicable charges.

1. Reservation Charge:

The monthly Reservation Charge shall be the applicable reservation rate multiplied by the Customer's Maximum Daily Quantity (MDQ), as specified in the Customer's FTSA.

Reservation Rates:	Per Dth Per Month
SFV Rates:	5.5594 (R)

Customer's obligation to pay the Reservation Charge each month is absolute and unconditional and is independent of Customer's ability to obtain export authorization from the National Energy Board of Canada, Canadian provincial removal authority, and/or import authorization from the United States Department of Energy. Customer's obligation to pay the Reservation Charge shall be unaffected by the quantity of gas transported by PG&E to Customer's Delivery Point(s) on the Pipeline Expansion.

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* PG&E's gas tariffs are on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-XF Sheet 2

PIPELINE EXPANSION FIRM INTRASTATE TRANSPORTATION SERVICE

RATES: (Cont'd.)

2. Usage Charge:

In addition to the Reservation Charge described above, Customer shall pay a usage charge for each decatherm equal to the applicable usage rate times the quantity of gas received on the Customer's behalf, less the applicable shrinkage allowance in the current month.

Usage Rates:	Per Dth
SFV Rates:	0.0035 (I)

CREDIT-WORTHINESS: The Customer must meet the creditworthiness requirements set forth in Rule 25.

SERVICE AGREEMENT: Customer must have executed a Pipeline Expansion Firm Transportation Service Agreement (Form No. 79-791) prior to the implementation date of the Gas Accord Settlement on March 1, 1998, in order to qualify for service under this schedule.

NOMINATIONS: Nominations are required for gas supplies delivered under this rate schedule. See Rule 21 for details.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. See Rule 14 for details.

TEMPORARY ASSIGNMENT OF CAPACITY RIGHTS: Customer may assign all or a portion of its long-term firm capacity on the Pipeline Expansion to another party, subject to the creditworthiness requirements set forth in Rule 25. In order to assign capacity, Customer must provide PG&E written notice, using the Assignment of Gas Transmission Services (Form No. 79-867).

RECEIPT POINTS: PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specified in Exhibit A to the FTSA. On any given day, the total amount of gas nominated for firm transportation service at all Receipt Points may not exceed Customer's MDQ, as specified in the FTSA.

DELIVERY POINTS: Customer may nominate only to the Delivery Point set forth in Exhibit A to the Customer's FTSA. Customer is responsible for separately arranging for transportation of its gas between the Delivery Point and the ultimate end-use destination(s).

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

BALANCING: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

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PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

1st Light Energy
AT&T
Alcantar & Kahl LLP
Anderson & Poole
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Braun Blaising McLaughlin, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine
Casner, Steve
Cenergy Power
Center for Biological Diversity
City of Palo Alto
City of San Jose
Clean Power
Coast Economic Consulting
Commercial Energy
County of Tehama - Department of Public Works
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Dept of General Services
Division of Ratepayer Advocates
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
G. A. Krause & Assoc.
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
In House Energy
International Power Technology
Intestate Gas Services, Inc.
K&L Gates LLP
Kelly Group
Linde
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.
North America Power Partners
Occidental Energy Marketing, Inc.
OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
SCE
SDG&E and SoCalGas
SPURR
San Francisco Public Utilities Commission
Seattle City Light
Sempra Utilities
SoCalGas
Southern California Edison Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
Tiger Natural Gas, Inc.
TransCanada
Utility Cost Management
Utility Power Solutions
Utility Specialists
Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)