STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
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April 23, 2015

Advice Letter 3547-G

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SUBJECT: Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2015

Dear Ms. Allen:

Advice Letter 3547-G is approved as of April 20, 2015, for rates effective January 1, 2015. Pursuant to recommendations by the California State Auditor, Energy Division staff is currently conducting in-depth reviews of PG&E gas balancing accounts. Balances in all accounts authorized for recovery are subject to audit, verification and adjustment.

Sincerely,

Edward Randolph
Director, Energy Division

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December 23, 2014

Advice 3547-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, 2015

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, 2015.

Consistent with prior years, this AGT advice letter does not include the 2015 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, 2014, PG&E filed its Annual Gas True-Up (AGT)[1] Advice Letter 3529-G, requesting approval to amortize forecast December 31, 2014 gas transportation balancing account balances in rates effective January 1, 2015. On December 19, 2014, Energy Division verbally confirmed that they had approved Advice 3529-G and that the disposition letter is forthcoming.

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

[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 that were provided in Advice 3529-G using November 30, 2014 recorded balances as the starting point.[2]

In Advice 3529-G, PG&E provided a preliminary estimate of its 2015 gas transportation revenue requirements, which at the time were estimated to be $2,684 million. In this advice letter, PG&E proposes to recover its final authorized 2015 gas transportation revenue requirements totaling $2,744 million, which is a $242 million increase compared to revenue requirements in present rates. The 2015 gas transportation revenue requirements include end-user transportation costs, gas PPP surcharges (which were submitted for Commission approval in Advice 3528-G), and gas transmission and storage (i.e., Gas Accord V or GAV) unbundled costs (See Table 1 below).

Table 1
Proposed Gas Transportation Revenue Requirements
Effective January 1, 2015
(in $ millions)[3]

Description	Currently in Rates	Proposed	Change
End-Use Gas Transportation	$2,076	$2,299	$223
Gas Accord Unbundled Costs	$170	$173	$3
Gas PPP Surcharges	$256	$272	$16
Total Gas Transportation Revenue Requirements	**$2,502**	**$2,744**	**$242**

Attachment 1 and 1A summarize the proposed 2015 gas transportation revenue requirements. Attachment 2 summarizes the gas transportation balancing accounts, which PG&E proposes to amortize in 2015. Attachments 3 through 6 provide rates and surcharges incorporating: (1) amounts previously authorized to be recovered in rates, effective January 1, 2015; and (2) the forecast December 31, 2014 account balances to be amortized in 2015.

Recovery of Transportation Balancing Accounts Already Approved for Amortization in the 2015 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

[2] Advice Letter 3529-G used September 30, 2014 recorded balances as the starting point for December 31, 2014 forecast balancing account balances.

[3] This table does not include the 2015 gas procurement-related revenue requirement changes, which will be submitted concurrently in PG&E's monthly core procurement advice letter.

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:

1) Forecasting the December 31, 2014 balance for each gas transportation balancing and memorandum account to be updated in the AGT based on the November 30, 2014[4] recorded balances and a forecast of costs and revenues, including interest, through December 31, 2014; and

2) Calculating the customer class charge components by dividing the forecasted December 31, 2014 balancing account balance by PG&E's currently adopted BCAP throughput forecast (D.10-06-035).

Attachment 2 summarizes the forecast December 31, 2014 balances for gas transportation balancing accounts using recorded balances through November 30, 2014. The total December 31, 2014 gas transportation balancing account balances are projected to be undercollected by $475 million, as shown in Attachment 1, line 1, and Attachment 2, line 26. This represents a $300 million increase in the gas transportation balancing account undercollections from those currently amortized in gas transportation rates.

The remainder of this section describes the balancing accounts that will be amortized through this AGT advice letter, effective January 1, 2015.

Certain account balances are recovered in rates through the Core Fixed Cost Account (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, 2014 balance to the appropriate subaccount of the CFCA and/or NCA, once the AGT is approved.

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

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 three 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

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[4] The PPP surcharge balancing accounts are included in the PPP surcharge proposed in Advice 3528-G. As a result, these PPP surcharge balancing accounts use September 30, 2014 recorded balances as the starting point of their respective December 30, 2014 forecast balances.

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 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; and

(iii) The Assembly Bill (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 $463.0 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 $443.3 million undercollection in the Distribution Cost subaccount. On August 14, 2014, the CPUC issued D.14-08-032, which adopted among other things, PG&E's gas distribution revenue requirement for the 2014-2016 GRC period, effective January 1, 2014.[5] On August 25, 2014, PG&E filed Advice 3505-G, to implement the resulting rate change, effective September 1, 2014. Because the GRC decision was not implemented until September 1, 2014, the CFCA and NCA forecast year-end balances reflect the increased amounts that PG&E was not able to collect through rates between January 1 and August 31, 2014; and

(ii) A forecasted $19.7 million undercollection in the Core Cost subaccount.

Noncore Customer Class Charge Account - (Attachment 2, Lines 3-4)

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;

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[5] On April 18, 2013, the CPUC issued D. 13-04-023 granting PG&E's request to make its 2014 GRC revenue requirement effective January 1, 2014, including interest.

(ii) The Distribution subaccount, which recovers the noncore distribution portion of interim gas revenue requirement changes 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

(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 $12.5 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 $16.6 million overcollection in the Noncore subaccount; and

(ii) A forecasted $4.1 million undercollection in the Distribution subaccount.

AB 32 Cost of Implementation Fee – (Attachment 2, Line 14)

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 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 2015 COI rates to reflect a reduction of the volumes associated with exempt customers. The AGT balance proposed to be amortized in 2015 rates consists of a forecasted $2.8 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 2014 plus a small forecast undercollection of the adopted COI costs included in 2014 rates.

Core Brokerage Fee Balancing Account (CBFBA) - (Attachment 2, Line 5)

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 $1.6 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 6)

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 $46.6 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 7)

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 $462,000 undercollection in the BCA as of December 31, 2014.

Affiliate Transfer Fees Account (ATFA) - (Attachment 2, Line 8)

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 approving PG&E to become a wholly owned subsidiary of a holding company (D. 96-11-017). This AGT forecasts a $162,000 overcollection in the ATFA, which represents activity in the account for 2014. The ATFA balance is included in the rate component of the Distribution Cost subaccount of the CFCA and the Distribution Cost subaccount of the NCA.

Customer Energy Efficiency Incentive Account (CEEIA) - (Attachment 2, Line 9)

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 requested earnings for program year 2012 and the first part of the 2013 EE incentive award as authorized by Resolution 3497-G/approval of Advice 3492-G-A. Interest does not accrue in this subaccount pursuant to D.07-09-043. This AGT includes a forecasted $7.1 million undercollected balance, which will be recovered through the CEE Incentive rate component.

SmartMeter™ Opt-Out Program Balancing Account (SOPBA-G) – (Attachment 2, Line 10)

On September 29, 2014, in accordance with D.14-08-032, PG&E filed Advice 3519-G to establish the SOPBA-G. Decision 14-08-032 was issued by the CPUC on August 14, 2014 and approved PG&E's GRC base revenue requirements. Additionally, D.14-08-032 required PG&E to file a Tier 1 advice letter to implement a two-way balancing account to track revenues and costs associated with the SmartMeter™ Opt-Out Program. In accordance with Gas Preliminary Statement Part DF, the SOPBA-G records the difference between actual revenue requirements related to PG&E's SmartMeter™ Opt-Out Program and the Program's adopted revenue requirements approved in D.14-08-032, pursuant to Ordering Paragraph 23 of D.14-08-032. The Program's actual revenue requirements include the incremental expenditures required to manage PG&E's SmartMeter™ Opt-Out Program and the associated revenues from fees received from Opt-Out Program participants. Costs that can be attributed specifically to gas service will be recorded to this account. On December 18, 2014, the CPUC approved D.14-12-078, which provides that the opt-out customer will pay the approved opt-out fees for three years. The remaining portion of revenue requirements that exceed the revenues collected from the opt-out charges will be allocated to the residential customer class as a whole. PG&E is in the process of determining billing system requirements related to this proceeding and plans to implement the results of the decision in rates as soon as practical.

California Solar Initiative Thermal Program Memorandum Account (CSITPMA) - (Attachment 2, Line 11)

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 SGIP and customers exempt pursuant to Public Utilities Code Section 2863(b)(4) are exempt from CSI Thermal Program charges. This AGT includes a forecasted $5.2 million undercollected balance in the CSITPMA as of December 31, 2014, and will be recovered in the CSITPMA rate component.

Adjustment Mechanism for Costs Determined in Other Proceedings (AMCDOP) – (Attachment 2, Line 12)

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 GAV 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 GAV 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 GAV 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 GAV 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 GAV 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 GAV Settlement Agreement.

The AGT includes a forecasted net $23.9 million undercollection 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 GAV rate tables.

Non-Tariffed Products and Services Balancing Account (NTBA-G) - (Attachment 2, Line 13)

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 $96,000 overcollected balance for this account, as of December 31, 2014; which will be transferred to the Distribution Cost subaccount of the CFCA.

Gas Pipeline Expense and Capital Balancing Account (GPECBA) – (Attachment 2, Line 15)

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. 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 is a one-way balancing account. Any unspent funds (i.e., overcollected balance) at the end of 2014 shall be returned to customers. 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, 2014.

(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 was capped at $299.2 million or $295.4 million (without franchise fees and uncollectibles or FF&U) under D.12-12-030. On November 20, 2014, the CPUC approved D.14-11-023 adopting the Settlement Agreement among PG&E, the Office of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN). Decision 14-11-023 adopted a reduced PSEP revenue requirement of $223.2 million. On December 1, 2014, PG&E filed Advice 3537-G to revise its authorized revenue requirement in the GPECBA to reflect the $223.2 million amount approved by D.14-11-023. This $76 million reduction ($299.2 million less $223.2 million) has also been reflected in the forecast balancing account balances of the Core Gas Pipeline Safety Balancing Account and the Noncore Gas Pipeline Safety Balancing Account, which are discussed below. In accordance with Advice 3537-G and Preliminary Statement Part CW, any unspent funds in the GPECBA shall be returned to customers through the Core and Noncore Gas Pipeline Safety Balancing Accounts. The Program Expense and Capital Subaccount is forecast to be undercollected as of December 31, 2014. Because this is a one-way balancing account, this amount will not be collected from customers.

(iii) In accordance with Section 4.5 of the Settlement Agreement approved by D.14-11-023, the December 31, 2014 forecast balancing account balances for the CFCA and NCA have been reduced by $3.7 million for 12 pipeline replacement projects that will not be operational in 2014, and by $0.3 million for 3 valve automation projects that will not be operational in 2014.[6]

(iv) Decision 12-12-030 adopted PG&E's forecast to replace, automate and upgrade 228 valves. PG&E forecasts automating 217 valves before the end of 2014. PG&E forecasted 80 valve automation projects, but will implement 84 valve automation projects by December 31, 2014. While PG&E will have automated fewer valves than originally planned, the additional four projects allowed PG&E to address more locations than originally planned, while enabling the same amount of pipeline miles to be isolated.

Gas Leak Survey and Repair Balancing Account (GLSRBA) – (Attachment 2, Line 16)

On September 29, 2014, in accordance with D.14-08-032, PG&E filed Advice 3518-G to establish the GLSRBA. The GLSRBA tracks and adjusts for the difference between authorized and recorded expenses for the following cost categories: 1) Natural Gas Distribution Leak Survey, 2) Leak Repair, 3) Meter Set Leak Repair, 4) Atmospheric Corrosion Inspection and 5) Tee Cap Repair. The GSLRBA excludes costs recovered through the Catastrophic Event Memorandum Account (CEMA). The GOBA is recovered through the CFCA and the NCA. This AGT includes a forecast $19.0 million net overcollection in the GLSRBA.

Gas Operational Cost Balancing Account (GOBA) – (Attachment 2, Line 17)

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 GAV 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 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.

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[6] In addition, in accordance with Ordering Paragraph 6 of D.12-12-030, the adopted capital cost cap and 2014 revenue requirement have been reduced by $221,000 and $10,000, respectively, for one pipeline replacement project that was cancelled and not replaced with another higher priority project.

This AGT includes a forecasted $11.7 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 18)

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, 2014.

TID Almond Power Plant Balancing Account (TIDBA) – (Attachment 2, Line 19)

The purpose of the TIDBA is to record the difference in revenue requirement based on the amount credited to rate base per the adopted GAV 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 $1.5 million overcollected balance in the TIDBA. In accordance with the GAV 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 20)

The RCESBA-G 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. This AGT includes a forecasted $2.5 million undercollected balance in the RCESBA as of December 31, 2014.

Gas Transmission & Storage Revenue Sharing Mechanism (GTSRSM) – (Attachment 2, Line 21)

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 the GAV Settlement Agreement. The over- or under-collections are determined by comparing revenue from implemented GAV 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 GAV 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 under-collections.

(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[7] 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 $4.9 million undercollected balance in the GTSRSM.

Core Gas Pipeline Safety Balancing Account (CGPSBA) – (Attachment 2, Line 22)

The purpose of the CGPSBA is to record and recover the core customers' portion of adopted forecast expense and, capital-related revenue requirements and revenues associated with PSEP through 2014, as authorized by the Commission in D.12-12-030. The CGPSBA consists of the following three subaccounts:

(i) The Backbone Subaccount, which records the difference between the adopted backbone revenue requirements and recorded backbone revenues related to PG&E's Implementation Plan;

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

(ii) The Local Transmission Subaccount, which records the difference between the adopted local transmission revenue requirements and recorded local transmission revenues related to PG&E's Implementation Plan; and

(iii) The Storage Subaccount, which records the difference between the adopted storage revenue requirements and recorded storage revenues related to PG&E's Implementation Plan.

This AGT includes a forecasted $36.6 million overcollected balance in the CGPSBA. As discussed in further detail below in the "Discussion of Recent CPUC Proceedings and Advice Letters" section, on November 20, 2014, the CPUC approved D.14-11-023 adopting the PSEP Update Settlement Agreement, which proposed a reduction in PG&E's authorized PSEP revenue requirements for the period from 2012 through 2014. This reduction has been included in the December 31, 2014 forecast balancing account balance for the CGPSBA.

Noncore Gas Pipeline Safety Balancing Account (NGPSBA) – (Attachment 2, Line 23)

The purpose of the NGPSBA is to record and recover the noncore customers' portion of adopted forecast expense and, capital-related revenue requirements and revenues associated with PSEP through 2014, as authorized by the Commission in D.12-12-030. The NGPSBA consists of the following three subaccounts:

(i) The Backbone Subaccount, which records the difference between the adopted backbone revenue requirements and recorded backbone revenues related to PG&E's Implementation Plan;

(ii) The Local Transmission Subaccount, which records the difference between the adopted local transmission revenue requirements and recorded local transmission revenues related to PG&E's Implementation Plan; and

(iii) The Storage Subaccount, which records the difference between the adopted storage revenue requirements and recorded storage revenues related to PG&E's Implementation Plan.

This AGT includes a forecasted $24.9 million overcollected balance in the NGPSBA. As discussed in further detail below in the "Discussion of Recent CPUC Proceedings and Advice Letters" section, on November 20, 2014, the CPUC approved D.14-11-023 adopting the PSEP Update Settlement Agreement, which proposed a reduction in PG&E's authorized PSEP revenue requirements for the period from 2012 through 2014. This reduction has been included in the December 31, 2014 forecast balancing account balance for the NGPSBA.

Integrity Management Expense Balancing Account (IMEBA) – (Attachment 2, Line 24)

The IMEBA tracks the aggregate amount of integrity management expenses incurred during the term of the GAV Settlement Agreement (2011 through 2014). The IMEBA was created in compliance with D.11-04-031 and records the difference between adopted revenue requirements and recorded expenses for the Settlement Period beginning January 1, 2011 and ending December 31, 2014. If the accumulated balance is a credit at December 31, 2014, a debit entry to transfer the December 31, 2014 accumulated balance to the Core Cost subaccount of the CFCA and the Noncore subaccount of the NCA. The distribution of the balance will be 50 percent to core and 50 percent to noncore. The IMEBA is forecasted to be undercollected in December 2014. The IMEBA is a one-way account, thus no balance will be collected from customers.

Mobile Home Park Balancing Account – Gas (MHPBA) – (Attachment 2, Line 25)

The MHPBA records and recovers actual incurred costs of implementing the voluntary program to convert the gas master-meter/submeter service at mobile home parks and manufactured housing communities to direct service by PG&E, pursuant to D.14-03-021. Advice 3473-G provided that the disposition of the balance in the account shall be through the AGT, via the CFCA and NCA, or other venues as approved by the Commission. This AGT includes a forecast $221,000 undercollected balance in the MHPBA.

<u>Discussion of Recent CPUC Proceedings and Advice Letters</u>

The following section highlights recent 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, 8)

On August 14, 2014, the CPUC issued D.14-08-032 in PG&E's 2014 GRC Application (A.12-11-009). Decision 14-08-032 adopted a new method for calculating the uncollectibles factor that will be revised annually. On November 24, 2014, PG&E filed Advice 3535-G (a Tier 1 advice letter) to update its 2015 uncollectibles factor and base revenue requirements.

Energy Efficiency Risk Reward Incentive Mechanism (RRIM) – (Attachment 2, Line 9)

PG&E filed Advice 3492-G/4451-E on June 30, 2014, and supplemental Advice 3492-G-A/4451-E-A on August 20, 2014, requesting approval of PG&E's 2012 and the first part of the 2013 EE incentive award in the amount of $37,338,440. These advice letters comply with OP 8 of D.12-12-032, and OPs 4 and 6 of D.13-09-023. On December 18, 2014, the CPUC approved Resolution 3497-G, which approved an incentive award of $36.3 million, the gas portion of which is $6.5 million based on the net benefit factor of 18 percent approved for the 2010-2012 portfolio in Advice 3065-G-A/3562E-A and 3065-G-B/3562-E-B and for the 2013-2014 portfolio in Advice 3356-G-A/4176-E-A. The December 31, 2014 forecast balance includes this amount plus the residual balance in the account.

Self-Generation Incentive Program Cost Recovery – (Attachment 1, Line 4)

Senate Bill (SB) 861, signed by Governor Brown on June 20, 2014, authorized the extension of the SGIP at the current annual funding level for an additional five years. On December 18, 2014, the CPUC approved D.14-12-033 authorizing PG&E to recover $36 million in 2015. The gas portion of $6.5 million is 18 percent of the total based on the adopted EE net benefit split adopted in Advice 3356-G-A/ 4176-E-A.

GHG Natural Gas Application

On December 18, 2014, the CPUC approved D.14-12-040 in the Natural Gas GHG OIR (R.14-03-003) regarding the Phase 1 issues of procurement authority, procurement rules, and cost recovery and the joint settlement submitted by the IOUs and ORA. The decision approved the settlement with modifications, including ordering that natural gas utilities not recover compliance costs in rates until revenue return is resolved in Phase 2 of the proceeding. Phase 2 is expected to begin in the early part of 2015, with a proposed decision no sooner than summer 2015. As a result, amounts have not been included in this AGT advice letter.

Pipeline Safety Enhancement Plan – (Attachment 1, Lines 17-20, and Attachment 2, Lines 15, 22-23)

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. On October 29, 2013, PG&E filed its Pipeline Safety Enhancement Program (PSEP) Update Application, A.13-10-017. On July 25, 2014, PG&E, ORA, and TURN filed a Joint Motion for approval of a PSEP Update Settlement Agreement (Settlement Agreement). Although PG&E's scope of work proposed in A.13-10-017 will not be reduced as a result of the July 2014 PSEP Update Settlement Agreement, the settling parties agreed to a reduction in the revenue requirement for 2012-2014. On November 20, 2014, the CPUC approved D.14-11-023, which approved the reduction in the revenue requirement proposed in the Settlement Agreement. Based on OP 2 of D.14-11-023, the reduced revenue requirement should be reflected in the PSEP balancing accounts. As a result, PG&E has reflected this $76 million reduction in the forecast balancing account balances of the CGPSBA and the NGPSBA in Lines 22 and 23 of Attachment 2 of this advice letter.[8] In accordance with Footnote 2 of the Settlement Agreement, post-2014 recovery of ongoing PSEP revenue requirements related to capital expenditures will be addressed in PG&E's 2015 GT&S Rate Case, A.13-12-012. Because the CPUC will not issue a decision on A.13-12-012 by December 2014, the ongoing 2015 PSEP revenue requirements included in PG&E's 2015 GT&S rate case have not been included in this AGT advice letter.

Presiding Officer's Decisions on PG&E's Natural Gas Order Instituting Investigations (OIIs)

On September 2, 2014, the Commission issued four Presiding Officers' Decisions (PODs) in the Commission's OIIs regarding PG&E's gas transmission system. On October 2, 2014, PG&E and other parties filed appeals of the PODs. PG&E will implement any changes to its gas department revenues required by the Commission's decisions once these cases have been resolved.

Gas Public Purpose Program Authorized Funding

This AGT incorporates gas PPP surcharge changes that were filed in Advice 3528-G on October 31, 2014. The gas PPP surcharge rate impacts on customers are shown in Attachment 1.

Public Utilities 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 $159.6 million for EE, ESA, CARE administrative expenses, RD&D, Board of Equalization, CPUC administrative costs and Statewide Marketing Education & Outreach administrative costs. This represents a $3.4 million increase from 2014;

[8] In accordance with Section 4.5.(a) of the Settlement Agreement approved by D.14-11-023, PG&E has reduced its forecast balancing account balances in the CFCA and the NCA by approximately $4 million to account for capital projects that will not be operational in 2014. In addition, the forecast balances in the CFCA and NCA have been reduced by approximately $10,000 to account for a pipeline replacement project that was cancelled and not replaced with another higher priority project.

2) Amortization over 12 months of forecasted December 31, 2014 balances in the PPP surcharge balancing accounts totaling a $1.7 million overcollection; and

3) A projected 2014 CARE revenue shortfall of $113.9 million, which represents a $5.0 million increase from the forecasted 2014 CARE customer discount. This shortfall is included in the PPP-CARE portion of the gas PPP surcharge rates for 2015 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 GAV Settlement in D.11-04-031, dated April 14, 2011. The rates submitted with this advice letter implement the 2015 interim rate provisions established in the GAV Settlement. Pursuant to Section 2.4, interim 2015 rates are set equal to the rates in effect on December 31, 2014, plus a 2 percent escalator for non G-XF backbone transmission, local transmission, storage, and customer access charge rates. The 2 percent escalation of non-G-XF backbone transmission and local transmission rates is applied to December 31, 2014 rates adjusted to remove the $30 million revenue sharing mechanism seed value credit adopted in Section 10.1.2 of the GAV Settlement.[9]

The following table shows resulting total annual 2015 revenue requirement changes.

Annual Gas Transmission and Storage Revenue Requirements

2015

($000)

Total Annual GT&S Revenue Requirements	GT&S 2014	GT&S Interim 2015	% Change
Total Backbone	$231,612	$236,128	1.9%
Total Local Transmission	$212,200	$216,444	2.0%
Total Storage	$ 85,583	$ 87,295	2.0%
Total Customer Access Charge	$ 5,026	$ 5,127	2.0%
Total GT&S	$534,421	$544,993	2.0%

[9] The revenue sharing mechanism was established to apply from 2011 through 2014, the term of the GAV Settlement (Section 10.1).

Attachment 6 provides an update of the GT&S revenue requirements and rates tables, included in Appendix A of the GAV Settlement.

Backbone and Local Transmission Adder Project Rate Adjustments

Section 7.4 of the GAV Settlement addresses treatment of costs associated with various Backbone and Local Transmission adder projects. Under the terms of the GAV 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 nor in 2014. Accordingly, Local Transmission rates effective January 1, 2014, were adjusted to remove recovery of the Line 304, Line 407 Phase 1, and Line 407 Phase 2 adder project revenue requirements.[10]

The GAV Settlement identified three backbone transmission adder projects. None of these projects became operational during the Settlement period. The revenue requirements associated with these backbone transmission adder projects are not included in the revenue requirements proposed to be collected through 2015 backbone transmission rates.[11]

Effective Date

PG&E requests that this Tier 1 filing be approved effective January 1, 2015.

Changes to core gas transportation rates will be incorporated into the monthly core procurement advice filing for rates effective January 1, 2015.

Protests

Anyone wishing to protest this advice letter may do so by sending a letter by January 12, 2015, 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:

[10] The 2014 Line 304 adder project revenue requirement removed from Local Transmission rates is $539,000. The 2014 Line 407 Phase 1 adder project revenue requirement removed from Local Transmission rates is $6.576 million. The 2014 Line 407 Phase 2 adder project revenue requirement removed from Local Transmission rates is $6.484 million.

[11] The 2014 P02158-Topock K-Units Replacement Phase 1 adder project revenue requirement removed from Backbone Transmission rates is $7.525 million. The Delevan K3/Gerber – Line 400 adder project revenue requirement removed from Backbone Transmission rates is $493,000. The Delevan K3/Gerber – Line 401 adder project revenue requirement removed from Backbone Transmission rates is $518,000.

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:

Meredith Allen
Senior Director, Regulatory Relations
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.

/S/

Meredith Allen
Senior Director, Regulatory Relations

cc: 2009 Biennial Cost Allocation Proceeding (BCAP) (A.09-05-026)
Gas PPP Surcharge (R.13-11-005 (EE) and A.11-05-019 (ESA/CARE))
2011 Gas Transmission and Storage Proceeding (A.09-09-013)
2014 GRC Phase I (A.12-11-009)
AB 32 Natural Gas Supplier Cost Recovery (A.13-09-015)
PSEP Update (A.13-10-017)
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:

☐ ELC ☑ GAS

☐ PLC ☐ HEAT ☐ WATER

Contact Person: Kingsley Cheng

Phone #: (415) 973-5265

E-mail: k2c0@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **3547-G** **Tier: 1**

Subject of AL: **Annual Gas True-Up: Consolidated Gas Rate Update for Rates Effective January 1, 2015**

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

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? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

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: ____

Resolution Required? ☐Yes ☑No

Requested effective date: **January 1, 2015** No. of tariff sheets: **36**

Estimated system annual revenue effect (%): $2,744 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, 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.

Pending advice letters that revise the same tariff sheets: N/A

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:

California Public Utilities Commission
Energy Division
EDTariffUnit
505 Van Ness Ave., 4th Flr.
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Meredith Allen
Senior Director, 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
2015 ANNUAL GAS TRUE-UP

2015 ANNUAL END-USE TRANSPORTATION, GAS ACCORD REVENUE REQUIREMENTS, AND PUBLIC PURPOSE PROGRAMS AUTHORIZED FUNDING
($ THOUSANDS)

		A	B	C	D	E	
Line No.		**Present in Rates as of 9/1/14**	**Proposed as of 1/1/2015**	**Total Change**	**Core**	**Noncore / Unbundled**	Line No.
	END-USE GAS TRANSPORTATION						
1	Gas Transportation Balancing Accounts	174,813	475,100	300,287	327,906	(27,619)	1
2	GRC Distribution Base Revenues (includes distribution portion of Cost of Capital)	1,559,047	1,652,881	93,834	90,538	3,296	2
3	Pension	46,015	50,422	4,407	4,254	153	3
4	Self Generation Incentive Program Revenue Requirement	6,480	6,525	45	18	27	4
5	CPUC Fee	3,210	3,210	-	-	-	5
6	Core Brokerage Fee Credit	(6,583)	(6,583)	-	-	-	6
7	Less CARE discount recovered in PPP surcharge from non-CARE customers	(108,850)	(113,888)	(5,038)	(5,038)	-	7
8	FF&U	3,207	9,536	6,329	6,372	(43)	8
9	Total Transportation RRQ with Adjustments and Credits	1,677,339	2,077,203	399,864	424,050	(24,186)	9
10	Procurement-Related G-10 Total	(1,047)	(1,035)	12	12	-	10
11	Procurement-Related G-10 Total Allocated	1,047	1,035	(12)	(4)	(8)	11
12	Total Transportation Revenue Requirements Reallocated	1,677,339	2,077,203	399,864	424,058	(24,194)	12
	Gas Accord Transportation Revenue Requirements						
13	Local Transmission	212,200	216,444	4,244	2,707	1,537	13
14	Customer Access	5,026	5,127	101	-	101	14
15	Total Gas Accord Transportation RRQ	217,226	221,571	4,345	2,707	1,638	15
16	Implementation Plan Revenue Requirements						16
17	Implementation Plan - Local Transmission	134,616	-	(134,616)	(85,881)	(48,735)	17
18	Implementation Plan - Backbone	40,770	-	(40,770)	(17,462)	(23,308)	18
19	Implementation Plan - Storage	5,572	-	(5,572)	(3,291)	(2,281)	19
20	Total Implementation Plan Revenue Requirements	180,958	-	(180,958)	(106,634)	(74,324)	20
21	**Total End Use Gas Transportation RRQ**	**2,075,523**	**2,298,774**	**223,251**	**320,131**	**(96,880)**	21
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING						
22	Energy Efficiency	74,077	77,296	3,219	2,897	322	22
23	Energy Savings Assistance	67,982	68,858	876	788	88	23
24	Research and Development and BOE/CPUC Admin Fees	11,079	10,900	(179)	(113)	(66)	24
25	CARE Administrative Expense	2,806	3,001	195	133	62	25
26	Statewide Marketing, Education & Outreach - Phase 2	255	(477)	(732)	(659)	(73)	26
27	Total Authorized PPP Funding	156,199	159,578	3,379	3,046	333	27
28	PPP Surcharge Balancing Accounts	(9,295)	(1,740)	7,555	7,232	323	28
29	CARE discount recovered from non-CARE customers	108,850	113,888	5,038	3,661	1,377	29
30	**Total PPP Required Funding**	**255,754**	**271,726**	**15,972**	**13,939**	**2,033**	30
	GAS ACCORD UNBUNDLED COSTS						
31	Backbone Transmission	135,405	137,996	2,591	-	2,591	31
32	Storage	34,980	35,679	699	-	699	32
33	**Total Gas Accord Unbundled**	**170,385**	**173,675**	**3,290**	**-**	**3,290**	33
34	**TOTAL REVENUE REQUIREMENTS**	**2,501,662**	**2,744,175**	**242,513**	**334,070**	**(91,557)**	34

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

ATTACHMENT 1A

PACIFIC GAS AND ELECTRIC COMPANY
2015 ANNUAL GAS TRUE-UP

2015 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 1/1/2015	Core	Noncore / Unbundled	Line No.
	END-USE GAS TRANSPORTATION				
1	Gas Transportation Balancing Accounts	475,100	460,313	14,787	1
2	GRC Distribution Base Revenues	1,652,881	1,595,347	57,534	2
3	Pension	50,422	48,667	1,755	3
4	Self Generation Incentive Program Revenue Requirement	6,525	2,587	3,938	4
5	CPUC Fee	3,210	1,970	1,240	5
6	Core Brokerage Fee Credit	(6,583)	(6,583)	-	6
7	Less CARE discount recovered in PPP surcharge from non-CARE customers	(113,888)	(113,888)	-	7
8	FF&U	9,536	8,742	794	8
9	Total Transportation RRQ with Adjustments and Credits	2,077,203	1,997,155	80,048	9
10	Procurement-Related G-10 Total	(1,035)	(1,035)	-	10
11	Procurement-Related G-10 Total Allocated	1,035	408	627	11
12	Total Transportation Revenue Requirements Reallocated	2,077,203	1,996,528	80,675	12
	Gas Accord Transportation Revenue Requirements				
13	Local Transmission	216,444	138,046	78,398	13
14	Customer Access	5,127	-	5,127	14
15	Total Gas Accord Transportation RRQ	221,571	138,046	83,525	15
16	Implementation Plan Revenue Requirements				16
17	Implementation Plan - Local Transmission	-	-	-	17
18	Implementation Plan - Backbone	-	-	-	18
19	Implementation Plan - Storage	-	-	-	19
20	Total Implementation Plan	-	-	-	20
21	**Total End Use Gas Transportation RRQ**	**2,298,774**	**2,134,574**	**164,200**	21
	PUBLIC PURPOSE PROGRAMS (PPP) FUNDING				
22	Energy Efficiency	77,296	69,554	7,742	22
23	Energy Savings Assistance	68,858	61,961	6,897	23
24	Research and Development and BOE/CPUC Admin Fees	10,900	6,975	3,925	24
25	CARE Administrative Expense	3,001	1,811	1,190	25
26	Statewide Marketing, Education & Outreach - Phase 2	(477)	(429)	(48)	26
27	Total Authorized PPP Funding	159,578	139,872	19,706	27
28	PPP Surcharge Balancing Accounts	(1,740)	4,526	(6,266)	28
29	CARE discount recovered from non-CARE customers	113,888	68,733	45,155	29
30	**Total PPP Required Funding**	**271,726**	**213,131**	**58,595**	30
	GAS ACCORD UNBUNDLED COSTS				
31	Backbone Transmission	137,996	-	137,996	31
32	Storage	35,679	-	35,679	32
33	**Total Gas Accord Unbundled**	**173,675**	**-**	**173,675**	33
34	**TOTAL REVENUE REQUIREMENTS**	**2,744,175**	**2,347,705**	**396,470**	34

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

ATTACHMENT 2

AL 3547-G

PACIFIC GAS AND ELECTRIC COMPANY
2015 ANNUAL GAS TRUE-UP
BALANCING ACCOUNT FORECAST SUMMARY

($ THOUSANDS)

Line No.		Balance	Allocation		Balance	Allocation		Line No.
		Nov. 2014 Recorded Dec. 2014 Forecast	Core	Noncore	December 2013 Recorded *(1)*	Core	Noncore	
		A	B	C	D	E	F	
	GAS TRANSPORTATION BALANCING ACCOUNTS							
1	Core Fixed Cost Account (CFCA) - Distribution Cost Subaccount	$443,284	$443,284	$0	$55,850	$55,850	$0	1
2	CFCA - Core Cost Subaccount	$19,683	$19,683	$0	$4,994	$4,994	$0	2
3	Noncore Customer Class Charge Account (NCA) - Noncore Subaccount	($16,593)	$0	($16,593)	($3,652)	$0	($3,652)	3
4	NCA - Distribution Subaccount	$4,101	$0	$4,101	($896)	$0	($896)	4
5	Core Brokerage Fee Balancing Account	$1,644	$1,644	$0	$764	$764	$0	5
6	Hazardous Substance Mechanism	$46,555	$18,360	$28,195	$51,039	$20,129	$30,910	6
7	Balancing Charge Account	$462	$182	$280	($80)	($32)	($48)	7
8	Affiliate Transfer Fee Account	($162)	($157)	($5)	$0	$0	$0	8
9	Customer Energy Efficiency Incentive Recovery Account - Gas	$7,119	$7,057	$62	$3,983	$3,948	$35	9
10	SmartMeter™ Opt-Out Balancing Account	$0	$0	$0	$0	$0	$0	10
11	California Solar Initiative Thermal Program Memoradum Account	$5,211	$3,084	$2,127	$4,931	$1,945	$2,986	11
12	Adjustment Mechanism of Costs Determined in Other Proceedings	$23,868	$11,934	$11,934	$0	$0	$0	12
13	Non-Tariffed Products and Services Balancing Account	($96)	($96)	$0	($267)	($267)	$0	13
14	AB 32 Cost of Implementation Fee	$2,771 *(2)*	$1,584	$1,187	$4,815	$4,122	$693	14
15	GPECBA - CPUC Reimbursement Subaccount	$0	$0	$0	$0	$0	$0	15
16	Gas Leak Survey and Repair Balancing Account	($19,006)	($18,344)	($662)	$0	$0	$0	16
17	Gas Operational Cost Balancing Account	$11,690	$4,610	$7,080	$9,551	$3,767	$5,784	17
18	Pension Contribution Balancing Account	$0	$0	$0	$0	$0	$0	18
19	TID Almond Power Plant Balancing Account	($1,475)	($953)	($522)	($1,265)	($499)	($766)	19
20	Revised Customer Energy Statement Balancing Account	$2,502	$2,415	$87	($4,204)	($1,658)	($2,546)	20
21	GT&S Revenue Sharing Mechanism	$4,867 *(3)*	$2,433	$2,434	$10,985 *(4)*	$5,493	$5,492	21
22	Core Gas Pipeline Safety Balancing Account	($36,620)	($36,620)	$0	$0	$0	$0	22
23	Noncore Gas Pipeline Safety Balancing Account	($24,926)	$0	($24,926)	$0	$0	$0	23
24	Integrity Management Expense Balancing Account	$0	$0	$0	$0	$0	$0	24
25	Mobile Home Park Balancing Account	$221	$213	$8	$0	$0	$0	25
26	**Subtotal Transportation Balancing Accounts**	**$475,100**	**$460,313**	**$14,787**	**$136,548**	**$98,556**	**$37,992**	26
	PUBLIC PURPOSE PROGRAM (PPP) SURCHARGE BALANCING ACCOUNTS (5)							
27	PPP-Energy Efficiency	$11,323	$10,189	$1,134	$11,836	$10,651	$1,185	27
28	PPP-Low Income Energy Efficiency	$7,466	$6,719	$747	$4,938	$4,442	$496	28
29	PPP-Research Development and Demonstration	$194	$124	$70	$194	$124	$70	29
30	California Alternate Rates for Energy Account	($20,723)	($12,506)	($8,217)	($21,550)	($12,883)	($8,667)	30
31	**Subtotal Public Purpose Program Balancing Accounts**	**($1,740)**	**$4,526**	**($6,266)**	**($4,582)**	**$2,334**	**($6,916)**	31
32	**TOTAL BALANCING ACCOUNTS**	**$473,360**	**$464,839**	**$8,521**	**$131,966**	**$100,890**	**$31,076**	32

Footnotes:

1. These balances are the recorded balances as of December 2013. The 12/13 ending balances that were provided in the 2014 AGT AL 3447-G were the forecasted balances (based on recorded balances through November 2013).
2. 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.
3. The balance shown is the September 30, 2014 recorded balance, which will be transferred evenly (50/50) to the CFCA and NCA after the approval of the AGT advice letter.
4. This amount represents the September 30, 2013 recorded balance which was transferred to CFCA and NCA evenly.
5. The PPP-related balances (based on Sept 2014 recorded) were included in the 2015 PPP Gas Surcharge filed in AL 3528-G on October 31, 2014.

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, 2015 AGT/GT&S escalated 2% December Final Filing
AVERAGE END-USER GAS TRANSPORTATION RATES AND PUBLIC PURPOSE PROGRAM SURCHARGES
($/th; Annual Class Averages)(3)

Line No.	Customer Class	September 1, 2014 - GRC (A)			January 1, 2015 - AGT			Percentage Change From September 1, 2014		
		Transportation(1)	G-PPPS (2)	Total	Transportation	G-PPPS	Total	Transportation	G-PPPS	Total
	RETAIL CORE									
1	Residential Non-CARE (4)	$.766	$.084	**$.850**	$.907	$.090	**$.997**	18.4%	7.2%	17.3%
2	Small Commercial Non-CARE (4)	$.459	$.044	**$.504**	$.524	$.045	**$.569**	14.0%	0.7%	12.9%
3	Large Commercial	$.227	$.092	**$.319**	$.226	$.097	**$.324**	(0.5%)	6.4%	1.5%
4	NGV1 - (uncompressed service)	$.164	$.026	**$.189**	$.144	$.026	**$.170**	(12.2%)	1.9%	(10.3%)
5	NGV2 - (compressed service)	$1.445	$.026	**$1.470**	$1.700	$.026	**$1.726**	17.7%	1.9%	17.4%
	RETAIL NONCORE									
6	Industrial - Distribution	$.191	$.042	**$.232**	$.186	$.043	**$.229**	(2.6%)	4.3%	(1.4%)
7	Industrial - Transmission	$.064	$.034	**$.098**	$.039	$.035	**$.074**	(38.1%)	3.5%	(23.7%)
8	Industrial - Backbone	$.020	$.034	**$.054**	$.010	$.035	**$.045**	(52.1%)	3.5%	(17.5%)
9	Electric Generation - Transmission (G-EG-D/LT)	$.056		**$.056**	$.030		**$.030**	(45.5%)		(45.5%)
10	Electric Generation - Backbone (G-EG-BB)	$.020		**$.020**	$.009		**$.009**	(52.9%)		(52.9%)
11	NGV 4 - Distribution (uncompressed service)	$.191	$.026	**$.216**	$.186	$.026	**$.212**	(2.6%)	1.9%	(2.1%)
12	NGV 4 - Transmission (uncompressed service)	$.056	$.026	**$.081**	$.030	$.026	**$.056**	(45.9%)	1.9%	(30.8%)
	WHOLESALE CORE AND NONCORE (G-WSL) (1)									
13	Alpine Natural Gas	$.056		**$.056**	$.030		**$.030**	(45.4%)		(45.4%)
14	Coalinga	$.057		**$.057**	$.031		**$.031**	(44.7%)		(44.7%)
15	Island Energy	$.076		**$.076**	$.051		**$.051**	(32.8%)		(32.8%)
16	Palo Alto	$.052		**$.052**	$.026		**$.026**	(49.0%)		(49.0%)
17	West Coast Gas - Castle	$.215		**$.215**	$.231		**$.231**	7.6%		7.6%
18	West Coast Gas - Mather Distribution	$.257		**$.257**	$.287		**$.287**	11.5%		11.5%
19	West Coast Gas - Mather Transmission	$.060		**$.060**	$.034		**$.034**	(42.4%)		(42.4%)

(1) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable), distribution costs (where applicable), and AB32 Cost of Implementation Fee (wholesale and certain large customers are directly billed by the Air Resource board, and are exempt from PG&E's AB32 COI rate component of $0.00056 per therm). 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, 2015 AGT/GT&S ESCALATED 2% DECEMBER FINAL FILING
SUMMARY OF RATES (excluding procurement) BY CLASS BY MAJOR ELEMENTS
($/th; Annual Class Averages)(9)

		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)	$.04749	$.04749	$.04749	$.04749	$.04749	$.02325	$.02325	$.00000	$.02325	$.02325	$.02325	$.00000
2	Self Generation Incentive Program	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091	$.00091
3	CPUC and AB32 Cost of Implementation Fee (3)(8)	$.00125	$.00125	$.00125	$.00125	$.00125	$.00125	$.00125	$.00125	$.00125	$.00125	$.00058	$.00058
4	Balancing Accounts (2)	$.19743	$.12064	$.05547	$.03818	$.36371	$.01799	$.00942	$.00902	$.01799	$.00902	$.00784	$.00784
5	PSEP	($.01259)	($.01259)	($.01259)	($.01259)	($.01259)	($.00617)	($.00617)	($.00298)	($.00617)	($.00617)	($.00617)	($.00298)
6	Distribution - Annual Average (6)	$.67276	$.30737	$.12906	$.06758	$1.29942	$.14041	$.00892		$.14041		$.00279	$.00279
7	VOLUMETRIC RATE - Average Annual	$.90724	$.46506	$.22158	$.14281	$1.70018	$.17763	$.03758	$.00820	$.17763	$.02826	$.02921	$.00915
8	CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4)		$.05888	$.00449	$.00120		$.00804	$.00190	$.00161	$.00804	$.00190	$.00111	$.00020
9	CLASS AVERAGE TRANSPORTATION RATE	$.90724	$.52395	$.22607	$.14400	$1.70018	$.18567	$.03948	$.00981	$.18567	$.03016	$.03032	$.00934
10	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)	$.08989	$.04472	$.09743	$.02602	$.02602	$.04349	$.03488	$.03488	$.02602	$.02602		
11	END-USE RATE (7)	$.99713	$.56867	$.32350	$.17002	$1.72620	$.22916	$.07436	$.04469	$.21169	$.05618	$.03032	$.00934

		Wholesale						
				WC Gas Mather		Island		WC Gas
		Coalinga	Palo Alto	Dist.	Trans.	Energy	Alpine	Castle
	TRANSPORTATION CHARGE COMPONENTS							
12	Local Transmission (1)	$.02325	$.02325	$.02325	$.02325	$.02325	$.02325	$.02325
13	Self Generation Incentive Program	WHOLESALE CUSTOMERS EXCEPT FROM SGIP, AB32 COI, and CPUC FEE RATE COMPONENT						
14	CPUC and AB32 Cost of Implementation Fee (3)(8)							
15	Balancing Accounts (2)	$.00740	$.00749	$.02199	$.00749	$.00753	$.00736	$.01834
16	PSEP	($.00617)	($.00617)	($.00617)	($.00617)	($.00617)	($.00617)	($.00617)
17	Distribution - Annual Average			$.23831				$.17997
18	VOLUMETRIC RATE - Average Annual	$.02448	$.02457	$.27738	$.02457	$.02461	$.02444	$.21538
19	CUSTOMER ACCESS CHARGE - Class Average Volumetric Equivalent (4)	$.00683	$.00183	$.00973	$.00973	$.02641	$.00597	$.01571
20	CLASS AVERAGE TRANSPORTATION RATE	$.03131	$.02639	$.28711	$.03430	$.05102	$.03041	$.2310973
21	PUBLIC PURPOSE PROGRAM SURCHARGE/TAX (5)							
22	END-USE RATE	$.03131	$.02639	$.28711	$.03430	$.05102	$.03041	$.23110

NOTES
(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2015 Annual Gas True-Up Filing AL 3547-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, efective July 1, 2007 (including FF&U). G-EG customers pay a reduced CPUCfe per the 2010 BCAP D.10-06-035.
(4) Adopted in Decision 11-04-031 based on Appendix B, Table 12; updated in the 2015 Annual Gas True-Up Filing AL 3547-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 3528-G updated PG&E's 2015 PPP Surcharges efctive January 1, 2015.
(6) The G-NGV2 Distribution rate component incudes the cost ofcompression, 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 fom the CARE portion ofPG&E's Public Purpose Program Surcharge (G-PPPS) rates and cost recovery of the California Solar Initiative Thermal Program.
(8) AB32 provides the Air Resource Board recovery of its administration costs associated with the implementation ofAB32. Wholesale and certain large customers are directly billed by the ARB, and are exemptfom PG&E's cost ofimplementation component of$0.00056 per therm
(9) Rates are unrounded

Attachment 5

PACIFIC GAS AND ELECTRIC COMPANY

January 1, 2015 AGT/GT&S escalated 2% December Final Filing

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**	Noncore & Wholesale
1	Customer	$912,963	$796,534	$106,150	$2,271	$92	$0	$905,047	$5,620	$320	$0	$1,976	$0	$0	$0	$0	$0	$0	$0	$7,916
2	+ Distribution	$758,152	$528,744	$170,264	$7,513	$1,275	$0	$707,795	$32,373	$12,279	$0	$5,437	$0	$0	$0	$0	$149	$0	$119	$50,357
3	+ G-NGV2 Compression Cost	$2,969	$0	$0	$0	$0	$2,969	$2,969	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Allocation of Base Distribution Franchise Fees	$23,556	$18,648	$3,889	$138	$19	$42	$22,736	$535	$177	$0	$104	$0	$0	$0	$0	$2	$0	$2	$820
5	Allocation of Base Distribution Uncollectibles Expense	55,663	$4,484	$935	$33	$5	$10	$5,467	$129	$43	$0	$25	$0	$0	$0	$0	$0	$0	$0	$196
6	Totals Before Core Averaging	$1,703,303	$1,348,410	$281,238	$9,955	$1,391	$3,021	$1,644,015	$38,657	$12,818	$0	$7,542	$0	$0	$0	$0	$151	$0	$121	$59,289
7	Re-Allocation Due to Core Averaging*	($0)	($8,968)	$8,968	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	**Final Allocation of Distribution Revenue Requirement**	**$1,703,303**	**$1,339,442**	**$290,206**	**$9,955**	**$1,391**	**$3,021**	$1,644,015	**$38,657**	**$12,818**	**$0**	**$7,542**	**$0**	**$0**	**$0**	**$0**	**$151**	**$0**	**$121**	$59,289
9	**Distribution-Level Revenue Requirement Allocation %**	100.00000%	78.63791%	17.03783%	0.58445%	0.08165%	0.17735%	96.51819%	2.26950%	0.75256%	0.00000%	0.44280%	0.00000%	0.00000%	0.00000%	0.00000%	0.00886%	0.00000%	0.00709%	3.48081%

Total Core Brokerage Fee (w/out F&U) (6,470) (6,583) With F&U

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**	Noncore & Wholesale
10	Core Fixed Cost Acct. Bal. - Distribution Cost Subaccount	$443,284	$361,160	$78,250	$2,684	$375	$815	$443,284	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Core Fixed Cost Acct. Bal. - Core Cost Subaccount - ECPT	$19,683	$13,658	$5,381	$506	$137	$0	$19,683	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	*Mobile Home Parks Balancing Account*	$221	$175	$37	$1	$0	$0	$214	$5	$2	$0	$1	$0	$0	$0	$0	$0	$0	$0	$8
13	Noncore Customer Class Charge Account - ECPT	($16,593)	$0	$0	$0	$0	$0	$0	($971)	($5,358)	($43)	($10,062)	($20)	($9)	($119)	($2)	($4)	($2)	($3)	($16,593)
14	Noncore Customer Class Charge Account - Distribution Subacct	$4,101	$0	$0	$0	$0	$0	$0	$2,674	$887	$0	$522	$0	$0	$0	$0	$10	$0	$8	$4,101
15	*Gas Leak Survey & Repair Balancing Account*	($19,006)	($15,046)	($3,138)	($111)	($16)	($34)	($18,344)	($431)	($143)	$0	($84)	$0	$0	$0	$0	($2)	$0	($1)	($662)
16	SmartMeter™ Opt-Out Balancing Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Placeholder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Hazardous Substance Balance	$46,555	$12,740	$5,020	$472	$128	$0	$18,360	$1,650	$9,104	$74	$17,099	$33	$15	$202	$4	$6	$4	$4	$28,195
19	Non-Tariffed Products and Services	($96)	($67)	($26)	($2)	($1)	$0	($96)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Core Brokerage Fee Credit (Gas Brokerage Costs w/o FF&U)	($5,446)	($3,779)	($1,489)	($140)	($38)	$0	($5,446)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Core Brokerage Fee Credit (Sales/Marketing Costs w/o FF&U)	($1,024)	($901)	($120)	($3)	($0)	$0	($1,024)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Affiliate Transfer Fee Account	($162)	($128)	($27)	($1)	($0)	($0)	($157)	($4)	($1)	$0	($1)	$0	$0	$0	$0	($0)	$0	($0)	($6)
23	Balancing Charge Account	$462	$126	$50	$5	$1	$0	$182	$16	$90	$1	$170	$0	$0	$2	$0	$0	$0	$0	$280
24	G-10 Procurement-related Employee Discount Allocated	$1,035	$283	$112	$11	$3	$0	$408	$37	$202	$2	$380	$1	$0	$4	$0	$0	$0	$0	$627
25	Brokerage Fee Balance Account	$1,644	$1,141	$449	$42	$11	$0	$1,644	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Adjust. Mechanism Costs Determined Other Proceedings	$23,868	$8,281	$3,263	$307	$83	$0	$11,934	$698	$3,853	$31	$7,237	$14	$6	$86	$2	$3	$2	$2	$11,934
27	G-10 Procurement-related Employee Discount	($1,035)	($1,035)	$0	$0	$0	$0	($1,035)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	TID Almond Power Plant	($1,475)	($716)	($220)	($14)	($3)	$0	($953)	($50)	($200)	$0	($261)	($1)	($1)	($8)	($0)	($0)	($0)	($0)	($522)
29	RCESBA-G	$2,502	$1,981	$413	$15	$2	$4	$2,415	$57	$19	$0	$11	$0	$0	$0	$0	$0	$0	$0	$87
30	Gas Operational Cost Balancing Account	$11,690	$3,199	$1,260	$119	$32	$0	$4,610	$414	$2,286	$18	$4,293	$8	$4	$51	$1	$2	$1	$1	$7,080
31	WGSP Balancing Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	GT&S Revenue Sharing Mechanism	$4,867	$1,689	$665	$63	$17	$0	$2,433	$142	$786	$6	$1,476	$3	$1	$17	$0	$1	$0	$0	$2,433
33	Gas Meter Reading Costs Balancing Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Self Gen Incentive Program Forecast Period Cost	$6,525	$1,795	$707	$67	$18	$0	$2,587	$232	$1,283	$10	$2,409	$5	$0	$0	$0	$0	$0	$0	$3,939
35	Subtotals of Items Transferred to CFCA and NCA	$521,600	$384,556	$90,586	$4,020	$751	$785	$480,698	$4,470	$12,809	$99	$23,189	$44	$18	$236	$4	$16	$4	$12	$40,902
36	Re-Allocation Due to Core Averaging	$0	($2,200)	$2,200	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	Alloc. After Core Averaging	$521,600	$382,356	$92,786	$4,020	$751	$785	$480,698	$4,470	$12,809	$99	$23,189	$44	$18	$236	$4	$16	$4	$12	$40,902
38	Franchise Fees and Uncoll. Exp. on Items Above	$9,303	$6,674	$1,619	$70	$13	$14	$8,390	$78	$224	$2	$405	$1	$0	$3	$0	$0	$0	$0	$713
39	Subtotals with FF&U and Other Bal. Acct./Forecast Period Costs	$530,703	$389,029	$94,405	$4,090	$764	$799	$489,088	$4,548	$13,033	$101	$23,594	$45	$18	$239	$5	$17	$4	$12	$41,615
40	Total of Items Collected via CFCA, NCA, and NDFCA	$2,234,006	$1,728,471	$384,611	$14,045	$2,155	$3,820	$2,133,102	$43,204	$25,851	$101	$31,136	$45	$18	$239	$5	$168	$4	$133	$100,904

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**	Noncore & Wholesale
41	CEE Incentive	$7,119	$6,211	$828	$18	$1	$0	$7,057	$44	$2	$0	$15	$0	$0	$0	$0	$0	$0	$0	$62
42	AB32 ARB Implementation Fee	$2,771	$1,099	$433	$41	$11	$0	$1,584	$142	$785	$6	$251	$3	$0	$0	$0	$0	$0	$0	$1,187
43	CA Solar Hot Water Heating	$5,211	$1,983	$983	$92	$25	$0	$3,084	$323	$1,783	$14	$0	$6	$0	$0	$0	$0	$0	$0	$2,127
44	SmartMeter™ Project Balancing Account (SBA-G)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
45	CPUC FEE	$3,210	$1,368	$538	$51	$14	$0	$1,970	$177	$977	$8	$75	$4	$0	$0	$0	$0	$0	$0	$1,240
46	Subtotals for Customer Class Charge Items	$18,312	$10,661	$2,782	$202	$51	$0	$13,695	$686	$3,548	$29	$341	$13	$0	$0	$0	$0	$0	$0	$4,617
47	Re-Allocation Due to Core Averaging	($0)	($58)	$58	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
48	Allocation after Remaining Core Averaging	$18,312	$10,603	$2,840	$202	$51	$0	$13,695	$686	$3,548	$29	$341	$13	$0	$0	$0	$0	$0	$0	$4,617
49	Franch. Fee and Uncoll. Exp. on Items Above	$320	$185	$50	$4	$1	$0	$239	$12	$62	$1	$6	$0	$0	$0	$0	$0	$0	$0	$81
50	Subtotals of Other Costs	$18,631	$10,788	$2,889	$205	$51	$0	$13,934	$698	$3,610	$29	$347	$13	$0	$0	$0	$0	$0	$0	$4,697
51	Allocation of Total Transportation Costs	$2,252,637	$1,739,259	$387,500	$14,250	$2,206	$3,820	$2,147,036	$43,902	$29,462	$130	$31,483	$58	$18	$239	$5	$168	$4	$133	$105,601

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**	Noncore & Wholesale
52	Local Transmission Expense (Forecast Period Cost)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
53	Local Transmission Balancing Account	($26,649)	($10,975)	($4,315)	($444)	($123)	$0	($15,856)	($849)	($4,582)	$0	($5,225)	($19)	($8)	($102)	($2)	($3)	($1)	($2)	($10,793)
54	Backbone Transmission Expense (Forecast Period Cost)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
55	Backbone Transmission Balancing Account	($29,988)	($12,349)	($4,856)	($499)	($138)	$0	($17,843)	($683)	($3,686)	($29)	($7,637)	($15)	($7)	($82)	($2)	($2)	($1)	($2)	($12,145)
56	Storage (Forecast Period Cost)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
57	Storage Balancing Account	($4,909)	($2,022)	($795)	($82)	($23)	$0	($2,921)	($112)	($603)	($5)	($1,250)	($2)	($1)	($13)	($0)	($0)	($0)	($0)	($1,988)
58	Subtotal of Pipeline Safety Enhacement Cost	($61,546)	($25,346)	($9,966)	($1,025)	($283)	$0	($36,620)	($1,643)	($8,872)	($34)	($14,111)	($36)	($16)	($197)	($4)	($6)	($3)	($4)	($24,926)
59	Net End-User Transportation Excluding LT and CAC	$2,191,091	$1,713,914	$377,534	$13,225	$1,923	$3,820	$2,110,416	$42,259	$20,589	$96	$17,372	$22	$2	$42	$0	$162	$2	$129	$80,675

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**	Noncore & Wholesale
60	Local Transmission	216,444	103,489	32,107	1,969	480		138,046	7,303	28,845		40,752	124	119	1,134	34	46	17	25	78,398
61	Customer Access Charge	5,127	0	0	0			0	0	2,703	0	2,313		18	58	4	9	12	10	5,127
62	Total End-User Gas Accord Transportation Costs	221,571	103,489	32,107	1,969	480	0	138,046	7,303	31,547	0	43,064	124	136	1,193	38	55	29	35	83,525
63	Gross End-User Transportation Costs in Rates	2,412,662	1,817,403	409,643	15,195	2,403	3,820	2,248,462	49,562	52,137	96	60,436	146	138	1,235	39	217	31	164	164,200
64	Less Forecast CARE Discount recovered in PPP Surcharges	113,888	113,888					113,888												0
65	Net End-User Transportation Costs in Rates	2,298,773	1,703,515	409,641	15,195	2,403	3,820	2,134,574	49,562	52,137	96	60,436	146	138	1,235	39	217	31	164	164,200

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT 5 (continued)
January 1, 2015 AGT/GT&S escalated 2% December Final Filing
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**	Noncore & Wholesale
66	PPP-EE Surcharge	76,819	60,548	6,162	2,415	0		69,174	2,065	5,584	45		0							7,694
67	PPP-EE Balancing Account	11,323	8,925	908	356	0		10,189	304	823	7		0							1,134
68	PPP-ESA Surcharge	68,858	54,273	5,523	2,164	0		61,961	1,851	5,006	40		0							6,897
69	PPP-ESA Balancing Account	7,466	5,885	599	235	0		6,719	201	543	4		0							748
70	PPP - RD&D Programs	10,494	4,687	1,817	169	42		6,715	591	3,151	25		12							3,779
71	PPP - RD&D Balancing Account	194	87	34	3	1		124	11	58	0		0							70
72	PPP-CARE Discount Allocation Set Annually	113,888	44,500	21,707	2,019	507		68,733	7,056	37,649	305		146							45,156
73	PPP-CARE Administration Expense	3,001	1,173	572	53	13		1,811	186	992	8		4							1,190
74	PPP-CARE Balancing Account	(20,723)	(8,097)	(3,950)	(357)	(92)		(12,506)	(1,284)	(6,850)	(55)		(27)							-8,216
75	PPP-Admin Cost for BOF and CPUC	406	181	70	7	2		260	23	122	1		0							146
76	Subtotal	273,726.35	172,161	33,442	7,053	473		213,129	11,003	47,077	381	0	136	0	0	0	0	0	0	58,597
77	Re-Allocation Due to Core Averaging	(0)	(1,359)	1,359	0	0		(0)	0	0	0	0	0	0	0	0	0	0	0	0
78	Allocation after Remaining Averaging	$271,726	$170,802	$34,801	$7,053	$473		$213,129	$11,003	$47,077	$381	$0	$136	$0	$0	$0	$0	$0	$0	$58,597

79	Unbundled Gas Transmission and Storage Revenue Requirement	$173,675	
	TOTAL GAS REVENUE REQUIREMENT AND PPPS FUNDING REQUIREMENT IN RATES		
80	Total Transportation, PPPS and Unbundled Costs	2,744,175	(Total of lines 65, 78, and 79)
81	Cross-check with Gas Revenue Requirement Table	2,744,175	Attachment 1 Row 34
82	Difference	0	(Off due to rounding in Attachment 1)

* Residential and Small Commercial Classes are 5% averaged
** Wholesale Customer West Coast Gas is allocated 100% of its full distribution costs as of January 2015.

Advice 3547-G
December 23, 2014

Gas Accord V Settlement

D.11-04-031

Attachment 6 - Appendix A

2015 Interim Rate 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).

2015 Rates - Reflect interim rates as in PG&E's Gas Accord V Settlement Agreement D.11-04-031

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

Line No.		Gas Accord IV Core Redwood Annual Capacity (MDth/d)	Gas Accord V Allocation Factors	Gas Accord V Core Redwood Annual Capacity (MDth/d)	Gas Accord V Core Baja Annual Capacity (MDth/d)	Gas Accord V 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, 2015

Table A-3
GT&S Revenue Requirement
Including Core and Noncore Revenue Responsibility
($ Thousand)

Line		GA IV	GA V with 2013 COC and GHG Compressor Cost				GA V with 2013 COC and GHG Compressor Cost, excluding adder projects that did not go in effect in 2012, 2013 and 2014					
No.		2010	2011	2012	2013	2014	2011	2012	2013	2014	Interim 2015	2015 Escalator
	Core Revenue Requirements											
1	Backbone Transmission Base (1) (2) (5) (6)	86,138	93,414	95,901	94,506	96,208	93,414	95,901	94,506	96,208	98,132	2.0%
2	Backbone Transmission Adders	-	-	-	3,173	3,335	-	-	-	-	-	
3	Subtotal Backbone Transmission	86,138	93,414	95,901	97,679	99,543	93,414	95,901	94,506	96,208	98,132	2.0%
4	Local Transmission Base	104,752	122,972	131,618	128,003	130,693	122,972	131,618	128,003	130,693	133,307	2.0%
5	Local Transmission Adder (3) (7)	10,102	5,514	5,785	9,602	13,319	5,514	5,395	4,850	4,646	4,739	2.0%
6	Subtotal Local Transmission	114,854	128,486	137,403	137,605	144,013	128,486	137,013	132,853	135,339	138,046	2.0%
7	Storage (4) (8)	43,850	48,689	50,121	49,492	50,603	48,689	50,121	49,492	50,603	51,615	2.0%
8	Customer Access Charge	-	-	-	-	-	-	-	-	-	-	
9	Total Core (9)	$244,843	$270,589	$283,425	$284,776	$294,159	$270,589	$283,036	$276,851	$282,150	$287,793	2.0%
	Noncore / Unbundled Revenue Requirements											
10	Backbone Trans. Base w/o G-XF Contracts	147,825	123,774	132,655	128,787	129,574	123,774	132,655	128,787	129,574	132,165	2.0%
11	Backbone Transmission Adders	-	-	-	4,656	5,158	-	-	-	-	-	
12	Subtotal Backbone Transmission	147,825	123,774	132,655	133,444	134,732	123,774	$ 132,655	$ 128,787	$ 129,574	$ 132,165	2.0%
13	G-XF Contracts		6,875	6,448	5,978	5,831	6,875	$ 6,448	$ 5,978	$ 5,831	$ 5,831	0.0%
14	G-XF Contract Adders		-	-	-	43	-	-	-	-	-	
15	G-XF Contracts Subtotal	7,024	6,875	6,448	5,978	5,874	6,875	6,448	5,978	5,831	5,831	0.0%
16	Subtotal Backbone Transmission (5) (6)	154,849	130,648	139,103	139,422	140,606	130,648	139,103	134,765	135,405	137,996	1.9%
17	Local Transmission Base	44,823	63,623	68,774	70,132	74,223	63,623	68,774	70,132	74,223	75,707	2.0%
18	Local Transmission Adder (3) (7)	4,323	2,853	3,023	5,261	7,564	2,853	2,819	2,657	2,638	2,691	2.0%
19	Subtotal Local Transmission	49,146	66,476	71,797	75,392	81,787	66,476	71,593	72,789	76,861	78,398	2.0%
20	Storage (4) (8)	7,750	35,513	35,729	34,615	34,980	35,513	35,729	34,615	34,980	35,679	2.0%
21	Customer Access Charge	5,174	4,590	4,821	4,860	5,026	4,590	4,821	4,860	5,026	5,127	2.0%
22	Total Noncore / Unbundled (9)	$216,919	$237,227	$251,449	$254,288	$262,398	$237,227	$251,246	$247,029	$252,271	$257,200	2.0%
	Total											
23	Backbone Transmission Base w/o G-XF Contracts	233,963	217,188	228,556	223,294	225,781	217,188	228,556	223,294	225,781	230,297	2.0%
24	Backbone Transmission Adders	-	-	-	7,829	8,493	-	-	-	-	-	
25	Subtotal Backbone Trans. w/o G-XF Contracts	$233,963	217,188	228,556	231,123	234,274	217,188	$228,556	$223,294	$225,781	$230,297	2.0%
26	G-XF Contracts		6,875	6,448	5,978	5,831	6,875	$6,448	$5,978	$5,831	$5,831	0.0%
27	G-XF Contract Adders		-	-	-	43	-	$0	$0	$0	$0	
28	G-XF Contracts Subtotal	7,024	6,875	6,448	5,978	5,874	6,875	6,448	5,978	5,831	5,831	0.0%
29	Subtotal Backbone Transmission (5) (6)	240,987	224,062	235,004	237,101	240,148	224,062	235,004	229,271	231,612	236,128	1.9%
30	Local Transmission Base	149,576	186,595	200,392	198,135	204,916	186,595	200,392	198,135	204,916	209,014	2.0%
31	Local Transmission Adder (less 5%) (3) (7)	14,424	8,367	8,808	14,862	20,884	8,367	8,214	7,508	7,284	7,430	2.0%
32	Subtotal Local Transmission	164,000	194,962	209,200	212,997	225,800	194,962	208,606	205,643	212,200	216,444	2.0%
33	Storage (4) (8)	51,600	84,202	85,850	84,106	85,583	84,202	85,850	84,106	85,583	87,295	2.0%
34	Customer Access Charge	5,174	4,590	4,821	4,860	5,026	4,590	4,821	4,860	5,026	5,127	2.0%
35	Total GT&S (9)	$461,761	$507,817	$534,874	$539,064	$556,557	$507,817	$534,281	$523,880	$534,421	$544,993	2.0%

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A
Effective January 1, 2015

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.

(13) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S revenue requirement for backbone, local transmission, storage, and customer access charges are escalated 2%. Schedule G-XF revenue requirement continues to be based on Line 401 incremental costs.

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

A.09-09-013

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, ($000) per year											
			Core				Noncore				Total			
1	**Project (Planned Operation Date)**	($ million)	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

Line No.	Project	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

Line No.	Project	Estimated Capital	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.

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

Gas Accord V Settlement Agreement

Appendix A

Effective January 1, 2015

Table B-3

Firm Backbone Transportation
Annual Rates (AFT) -- SFV Rate Design
On-System Transportation Service
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)	Excluding Seed 2014 (5)	Escalated 2% Interim 2015 (5)
Redwood Path - Core (1)								
Reservation Charge	($/dth/mo)	4.3368	6.5162	6.4678	6.3001	6.3780	6.8816	7.0192
Usage Charge	($/dth)	0.0124	0.0102	0.0096	0.0091	0.0092	0.0073	0.0074
Total	($/dth @ Full Contract)	0.1550	0.2244	0.2223	0.2162	0.2188	0.2335	0.2382
Baja Path - Core (1)								
Reservation Charge	($/dth/mo)	9.2319	7.2499	7.3504	7.3313	7.5567	8.0603	8.2215
Usage Charge	($/dth)	0.0153	0.0111	0.0106	0.0102	0.0104	0.0085	0.0087
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2512	0.2588	0.2735	0.2790
Redwood Path - Noncore								
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.9034	7.8577	8.4518	8.6209
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0080	0.0060	0.0061
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663	0.2839	0.2896
Baja Path - Noncore								
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.9457	9.0486	9.6427	9.8356
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0087	0.0088	0.0069	0.0070
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3063	0.3239	0.3304
Silverado and Mission Paths								
Reservation Charge	($/dth/mo)	4.4828	4.8056	4.6413	4.4150	4.4293	4.7527	4.8477
Usage Charge	($/dth)	0.0060	0.0049	0.0059	0.0077	0.0082	0.0062	0.0063
Total	($/dth @ Full Contract)	0.1534	0.1628	0.1585	0.1528	0.1538	0.1625	0.1657

(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 True-up (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.

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

Table B-4

Firm Backbone Transportation
Annual Rates (AFT) -- MFV Rate Design
On-System Transportation Service
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)	Excluding Seed 2014 (5)	Escalated 2% Interim 2015 (5)
Redwood Path - Core (1)								
Reservation Charge	($/dth/mo)	3.3290	4.7466	4.6534	4.4923	4.5126	4.8690	4.9663
Usage Charge	($/dth)	0.0455	0.0684	0.0693	0.0685	0.0705	0.0735	0.0749
Total	($/dth @ Full Contract)	0.1549	0.2244	0.2223	0.2162	0.2188	0.2335	0.2382
Baja Path - Core (1)								
Reservation Charge	($/dth/mo)	7.0037	5.2811	5.2883	5.2276	5.3466	5.7029	5.8170
Usage Charge	($/dth)	0.0885	0.0758	0.0784	0.0794	0.0831	0.0860	0.0878
Total	($/dth @ Full Contract)	0.3188	0.2494	0.2523	0.2512	0.2588	0.2735	0.2790
Redwood Path - Noncore								
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.2084	5.2050	5.5985	5.7105
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0965	0.0952	0.0998	0.1018
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663	0.2839	0.2896
Baja Path - Noncore								
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8953	5.9939	6.3874	6.5151
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1090	0.1093	0.1139	0.1162
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3063	0.3239	0.3304
Silverado and Mission Paths								
Reservation Charge	($/dth/mo)	3.0839	3.2679	3.1639	3.1425	3.1566	3.3867	3.4544
Usage Charge	($/dth)	0.0518	0.0554	0.0545	0.0495	0.0500	0.0511	0.0522
Total	($/dth @ Full Contract)	0.1532	0.1628	0.1585	0.1528	0.1538	0.1625	0.1657

(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.

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A
Effective January 1, 2015
Table B-5

Firm Backbone Transportation
Seasonal Rates (SFT) -- SFV Rate Design
On-System Transportation Service
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)	Excluding Seed 2014 (5)	Escalated 2% Interim 2015 (5)
Redwood Path								
Reservation Charge	($/dth/mo)	10.4795	9.9714	10.0125	9.4840	9.4293	10.1422	10.3450
Usage Charge	($/dth)	0.0082	0.0101	0.0100	0.0095	0.0096	0.0072	0.0074
Total	($/dth @ Full Contract)	0.3527	0.3379	0.3392	0.3213	0.3196	0.3407	0.3475
Baja Path - Core (1)								
Reservation Charge	($/dth/mo)	11.0784	8.6999	8.8204	8.7976	9.0680	9.6723	9.8658
Usage Charge	($/dth)	0.0183	0.0133	0.0127	0.0122	0.0125	0.0102	0.0104
Total	($/dth @ Full Contract)	0.3825	0.2993	0.3027	0.3015	0.3106	0.3282	0.3348
Baja Path - Noncore								
Reservation Charge	($/dth/mo)	11.0784	10.8643	11.0843	10.7348	10.8584	11.5713	11.8027
Usage Charge	($/dth)	0.0183	0.0107	0.0107	0.0104	0.0106	0.0082	0.0084
Total	($/dth @ Full Contract)	0.3825	0.3679	0.3752	0.3633	0.3676	0.3887	0.3964
Silverado and Mission Paths								
Reservation Charge	($/dth/mo)	5.3794	5.7667	5.5695	5.2980	5.3151	5.7032	5.8173
Usage Charge	($/dth)	0.0071	0.0058	0.0071	0.0092	0.0098	0.0075	0.0076
Total	($/dth @ Full Contract)	0.1840	0.1954	0.1902	0.1834	0.1846	0.1950	0.1989

(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.

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A

Effective January 1, 2015

Table B-6

Firm Backbone Transportation
Seasonal Rates (SFT) -- MFV Rate Design
On-System Transportation Service
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (2)	2012	2013 (3)	2014 (4)	Excluding Seed 2014 (5)	Escalated 2% Interim 2015 (5)
Redwood Path								
Reservation Charge	($/dth/mo)	6.0840	6.4905	6.5491	6.2501	6.2460	6.7182	6.8526
Usage Charge	($/dth)	0.1528	0.1245	0.1238	0.1159	0.1142	0.1198	0.1222
Total	($/dth @ Full Contract)	0.3528	0.3379	0.3392	0.3213	0.3196	0.3407	0.3475
Baja Path - Core (1)								
Reservation Charge	($/dth/mo)	8.4044	6.3373	6.3460	6.2731	6.4159	6.8435	6.9804
Usage Charge	($/dth)	0.1063	0.0910	0.0941	0.0952	0.0997	0.1032	0.1053
Total	($/dth @ Full Contract)	0.3826	0.2993	0.3027	0.3015	0.3106	0.3282	0.3348
Baja Path - Noncore								
Reservation Charge	($/dth/mo)	8.4044	7.0717	7.2502	7.0744	7.1926	7.6649	7.8182
Usage Charge	($/dth)	0.1063	0.1354	0.1368	0.1308	0.1311	0.1367	0.1394
Total	($/dth @ Full Contract)	0.3826	0.3679	0.3752	0.3633	0.3676	0.3887	0.3964
Silverado and Mission Paths								
Reservation Charge	($/dth/mo)	3.7008	3.9215	3.7967	3.7710	3.7879	4.0640	4.1453
Usage Charge	($/dth)	0.0622	0.0665	0.0654	0.0594	0.0601	0.0614	0.0626
Total	($/dth @ Full Contract)	0.1839	0.1954	0.1902	0.1834	0.1846	0.1950	0.1989

(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.

(4) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A
Effective January 1, 2015

Table B-7

As-Available Backbone Transportation
On-System Transportation Service
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		2010	2011 (1)	2012	2013 (2)	2014 (3)	Excluding Seed 2014 (4)	Escalated 2% Interim 2015 (4)
Redwood Path								
Usage Charge	($/dth)	0.3528	0.3379	0.3392	0.3213	0.3196	0.3407	0.3475
Baja Path								
Usage Charge	($/dth)	0.3826	0.3679	0.3752	0.3633	0.3676	0.3887	0.3964
Silverado Path								
Usage Charge	($/dth)	0.1839	0.1954	0.1902	0.1834	0.1846	0.1950	0.1989
Mission Path								
Usage Charge	($/dth)	0.0000	0.0000	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.

(4) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

Appendix A
Effective January 1, 2015

Table B-8

Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)	Excluding Seed 2014 (4)	Escalated 2% Interim 2015 (4)
SFV Rate Design								
Redwood, Silverado and Mission Paths Off-System								
Reservation Charge	($/dth/mo)	8.7329	8.3095	8.3437	7.9034	7.8577	8.4518	8.6209
Usage Charge	($/dth)	0.0070	0.0084	0.0083	0.0079	0.0080	0.0060	0.0061
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663	0.2839	0.2896
Baja Path Off-System								
Reservation Charge	($/dth/mo)	9.2319	9.0536	9.2370	8.9457	9.0486	9.6427	9.8356
Usage Charge	($/dth)	0.0153	0.0089	0.0089	0.0087	0.0088	0.0069	0.0070
Total	($/dth @ Full Contract)	0.3188	0.3066	0.3126	0.3028	0.3063	0.3239	0.3304
MFV Rate Design								
Redwood, Silverado and Mission Paths Off-System								
Reservation Charge	($/dth/mo)	5.0700	5.4087	5.4576	5.2084	5.2050	5.5985	5.7105
Usage Charge	($/dth)	0.1274	0.1038	0.1032	0.0965	0.0952	0.0998	0.1018
Total	($/dth @ Full Contract)	0.2941	0.2816	0.2826	0.2678	0.2663	0.2839	0.2896
Baja Path Off-System								
Reservation Charge	($/dth/mo)	7.0037	5.8930	6.0418	5.8953	5.9939	6.3874	6.5151
Usage Charge	($/dth)	0.0885	0.1129	0.1140	0.1090	0.1093	0.1139	0.1162
Total	($/dth @ Full	0.3188	0.3066	0.3126	0.3028	0.3063	0.3239	0.3304
As-Available Service								
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore								
Usage Charge	($/dth)	0.3528	0.3379	0.3392	0.3213	0.3196	0.3407	0.3475
Mission Paths (From on-system storage) Off-System								
Usage Charge	($/dth)	0.0000	0.0000	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	0.3887	0.3964

(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.

(4) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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) Dollar difference are due to rounding.

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A
Effective January 1, 2015

Table B-9

Firm Transportation
Expansion Shippers -- Annual Rates (G-XF)
SFV Rate Design
2015 Interim Rates

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)	2015 (4)
SFV Rate Design							
Reservation Charge	($/dth/mo)	6.3182	6.1394	6.2159	5.7146	5.5594	5.5594
Usage Charge	($/dth)	0.0019	0.0013	0.0015	0.0031	0.0035	0.0035
Total	($/dth @ Full Contract)	0.2096	0.2032	0.2059	0.1910	0.1863	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.

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, schedule G-XF 2015 interim rates continues to be based on Line 401 incremental costs.

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.

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A

Effective January 1, 2015

Table B-10

Storage Services

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)	2015 (4)
Core Firm Storage (G-CFS)							
Reservation Charge	($/dth/mo)	0.1092	0.1293	0.1248	0.1232	0.1260	0.1285
Standard Firm Storage (G-SFS)							
Reservation Charge	($/dth/mo)	0.1350	0.3008	0.2451	0.2374	0.2399	0.2447
Negotiated Firm Storage (G-NFS)							
Injection	($/dth/d)	15.6336	6.1656	6.1542	5.9623	6.0252	6.1457
Inventory	($/dth)	1.6205	2.9461	2.9407	2.8489	2.8790	2.9366
Withdrawal	($/dth/d)	11.7865	21.3468	21.3075	20.6428	20.8607	21.2779
Negotiated As-Available Storage (G-NAS) - Maximum Rate							
Injection	($/dth/d)	15.6336	6.1656	6.1542	5.9623	6.0252	6.1457
Withdrawal	($/dth/d)	11.7865	21.3468	21.3075	20.6428	20.8607	21.2779
Market Center Services (Parking and Lending Services)							
Maximum Daily Charge ($/Dth/d)		0.9702	1.1053	1.1136	1.0821	1.0986	1.1206
Minimum Rate (per transaction)		$ 57.00	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.

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S 2015 interim storage rates are escalated 2%.

Not

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.

D.11-04-031

Gas Accord V Settlement Agreement

Appendix A

Effective January 1, 2015

Table B-11

Local Transmission Rates
($/dth)

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010 (1)	2011 (2)	2012	2013 (3)	2014 (4)	Excluding Seed 2014 (5)	Escalated 2% 2015 (5)
Base Rates:								
Core Retail		0.3764	0.4118	0.4182	0.4074	0.4173	0.4496	0.4586
Noncore Retail and Wholesale		0.1628	0.2031	0.1933	0.1912	0.2043	0.2201	0.2245
Rate Adders:								
Core								
	L-304		0.0000	0.0013	0.0012	0.0012	0.0012	0.0012
	L-406	0.0115	0.0248	0.0185	0.0166	0.0160	0.0160	0.0163
	L-407 Phase 1		0.0000	0.0000	0.0151	0.0144	0.0144	0.0147
	L-407 Phase 2		0.0000	0.0000	0.0000	0.0142	0.0142	0.0145
	Total	0.0115	0.0248	0.0198	0.0330	0.0458	0.0458	0.0467
Noncore Retail & Wholesale								
	L-304		0.0000	0.0006	0.0006	0.0006	0.0006	0.0006
	L-406	0.0050	0.0108	0.0085	0.0078	0.0078	0.0078	0.0080
	L-407 Phase 1		0.0000	0.0000	0.0071	0.0071	0.0071	0.0072
	L-407 Phase 2		0.0000	0.0000	0.0000	0.0070	0.0070	0.0071
	Total	0.0050	0.0108	0.0091	0.0155	0.0224	0.0224	0.0229
Total Base plus Adder:								
Core Retail		0.3879	0.4367	0.4380	0.4404	0.4631	0.4954	0.5053
Noncore Retail and Wholesale		0.1678	0.2139	0.2024	0.2066	0.2267	0.2425	0.2474

(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.

(5) Consistent with Section 10.1.2 of the Gas Accord V Settlement, the 2014 revenue requirement used as the basis for calculating post-settlement agreement period 2015 interm GT&S rates are not reduced by the revenue sharing mechanism seed value. The resulting 2014 rates are escalated 2% consistent with Section 2.4 of the Gas Accord V Settlement to create interim 2015 rates.

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 A

Effective January 1, 2015

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, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

		GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)	2015 (4)
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	$62.12
Tier 2	5,001 to 10,000	$184.23	$161.87	$174.00	$175.40	$181.41	$185.04
Tier 3	10,001 to 50,000	$342.89	$301.27	$323.85	$326.46	$337.64	$344.40
Tier 4	50,001 to 200,000	$450.01	$395.39	$425.02	$428.44	$443.12	$451.98
Tier 5	200,001 to 1,000,000	$652.92	$573.67	$616.67	$621.63	$642.93	$655.79
Tier 6	1,000,001 and above	$5,538.45	$4,866.21	$5,230.96	$5,273.02	$5,453.67	$5,562.75
Wholesale ($/month)							
Alpine		$333.28	$286.66	$310.56	$313.06	$323.79	$330.27
Coalinga		$1,474.03	$1,267.85	$1,373.51	$1,384.55	$1,431.99	$1,460.63
Island Energy		$998.71	$859.01	$930.61	$938.09	$970.23	$989.63
Palo Alto		$4,914.73	$4,227.28	$4,579.59	$4,616.40	$4,774.56	$4,870.05
West Coast Gas - Castle		$856.26	$736.49	$797.87	$804.28	$831.84	$848.48
West Coast Gas - Mather		$782.50	$673.05	$729.14	$735.00	$760.18	$775.38

(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.

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S 2015 interim customer access charges are escalated 2%.

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 A

Effective January 1, 2015

Table B-13

Self Balancing Credit
$/dth

Revenue Requirement Caps and Rates with 2011 GRC, 2011 Pension Recovery Mechanism Revisions, 2013 Cost of Capital, GHG Compressor Cost, elimination of seed credit and 2% escalator for Interim 2015 Rates

	GA IV 2010	2011 (1)	2012	2013 (2)	2014 (3)	2015 (4)
Self Balancing Credit	($0.0096)	($0.0130)	($0.0131)	($0.0129)	($0.0132)	($0.0135)

(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.

(4) Consistent with Section 2.4 of the Gas Accord V Settlement, the GT&S 2015 interim self balancing credit are escalated 2%.

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.**
31737-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 12	31446-G
31738-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 13	31447-G
31739-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 14	31448-G
31740-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 15	31449-G
31741-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 16	31450-G
31742-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 17	31451-G
31743-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 18	31452-G
31744-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 19	31453-G
31745-G	GAS PRELIMINARY STATEMENT PART B DEFAULT TARIFF RATE COMPONENTS Sheet 20	31454-G
31746-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 2	31455-G
31747-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 3	31456-G
31748-G	GAS PRELIMINARY STATEMENT PART C GAS ACCOUNTING TERMS & DEFINITIONS Sheet 4	31457-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
31749-G	GAS SCHEDULE G-AA AS AVAILABLE TRANSPORTATION ON-SYSTEM Sheet 2	30984-G
31750-G	GAS SCHEDULE G-AAOFF AS-AVAILABLE TRANSPORTATION OFF-SYSTEM Sheet 2	30985-G
31751-G	GAS SCHEDULE G-AFT ANNUAL FIRM TRANSPORTATION ON-SYSTEM Sheet 2	30986-G
31752-G	GAS SCHEDULE G-AFTOFF ANNUAL FIRM TRANSPORTATION OFF-SYSTEM Sheet 2	30987-G
31753-G	GAS SCHEDULE G-BAL GAS BALANCING SERVICE FOR INTRASTATE TRANSPORTATION CUSTOMERS Sheet 4	30988-G
31754-G	GAS SCHEDULE G-CFS CORE FIRM STORAGE Sheet 1	30989-G*
31755-G	GAS SCHEDULE G-EG GAS TRANSPORTATION SERVICE TO ELECTRIC GENERATION Sheet 1	31459-G
31756-G	GAS SCHEDULE G-LEND MARKET CENTER LENDING SERVICES Sheet 1	30991-G
31757-G	GAS SCHEDULE G-LNG EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE Sheet 1	31460-G
31758-G	GAS SCHEDULE G-NAS NEGOTIATED AS-AVAILABLE STORAGE SERVICE Sheet 1	30993-G

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
31759-G	GAS SCHEDULE G-NFS NEGOTIATED FIRM STORAGE SERVICE Sheet 1	30994-G*
31760-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 1	30995-G
31761-G	GAS SCHEDULE G-NGV4 NONCORE NATURAL GAS SERVICE FOR COMPRESSION ON CUSTOMERS' PREMISES Sheet 2	31461-G
31762-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 1	30997-G
31763-G	GAS SCHEDULE G-NT GAS TRANSPORTATION SERVICE TO NONCORE END-USE CUSTOMERS Sheet 2	31462-G
31764-G	GAS SCHEDULE G-PARK MARKET CENTER PARKING SERVICES Sheet 1	30999-G
31765-G	GAS SCHEDULE G-SFS STANDARD FIRM STORAGE SERVICE Sheet 1	31000-G
31766-G	GAS SCHEDULE G-SFT SEASONAL FIRM TRANSPORTATION ON-SYSTEM ONLY Sheet 2	31001-G
31767-G	GAS SCHEDULE G-WSL GAS TRANSPORTATION SERVICE TO WHOLESALE/RESALE CUSTOMERS Sheet 1	31463-G
31768-G	GAS TABLE OF CONTENTS Sheet 1	31733-G

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
31769-G	GAS TABLE OF CONTENTS Sheet 2	31734-G
31770-G	GAS TABLE OF CONTENTS Sheet 3	31735-G
31771-G	GAS TABLE OF CONTENTS Sheet 4	31736-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	0.00853	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)
NCA – DISTRIBUTION SUBACCOUNT	0.00946	(I)	0.20468	(I)	0.13375	(I)	0.11925	(I)	0.10792	(I)
CPUC FEE	0.00069		0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)
CEE INCENTIVE	0.00000		0.00017	(I)	0.00017	(I)	0.00017	(I)	0.00017	(I)
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)
NCA - ARB AB32 COI	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)
NONCORE IMPLEMENTATION PLAN – LT	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)
NONCORE IMPLEMENTATION PLAN – BB	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN – Storage	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.03758**	(R)	**0.23291**	(R)	**0.16198**	(R)	**0.14748**	(R)	**0.13615**	(R)

* 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	0.00867	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)
NCA – DISTRIBUTION SUBACCOUNT	0.00000		0.27317	(I)	0.17741	(I)	0.15784	(I)	0.14255	(I)
CPUC FEE	0.00069		0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)
CEE INCENTIVE	0.00000		0.00017	(I)	0.00017	(I)	0.00017	(I)	0.00017	(I)
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	0.00000	(R)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)
NCA - ARB AB32 COI	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)
NONCORE IMPLEMENTATION PLAN – LT	0.00000		(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)
NONCORE IMPLEMENTATION PLAN - BB	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN - Storage	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.00820**	(R)	**0.30140**	(I)	**0.20564**	(R)	**0.18607**	(R)	**0.17078**	(R)

* 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	0.00857	(R)	0.00857	(R)
NCA – DISTRIBUTION SUBACCOUNT	0.00296	(I)	0.00296	(I)
CPUC FEE	0.00003		0.00003	
CSI- SOLAR THERMAL PROGRAM	0.00000		0.00000	
CEE INCENTIVE	0.00001	(I)	0.00001	(I)
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	0.02325	(I)	0.00000	(R)
NCA - ARB AB32 COI	0.00056	(R)	0.00056	(R)
NONCORE IMPLEMENTATION PLAN – LT	(0.00319)	(R)	0.00000	
NONCORE IMPLEMENTATION PLAN – BB	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN - Storage	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.02921**	(R)	**0.00915**	(R)

* 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

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	0.00749	(R)	0.00740	(R)	0.00753	(R)	0.00736	(R)
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)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)
NONCORE IMPLEMENTATION PLAN – LT	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)
NONCORE IMPLEMENTATION PLAN – BB	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN – Storage	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.02457**	(R)	**0.02448**	(R)	**0.02461**	(R)	**0.02444**	(R)

* 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	0.00749	(R)	0.00756	(R)	0.00748	(R)
NCA – DISTRIBUTION SUBACCOUNT	0.00000		0.25274	(I)	0.19083	(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)	0.02325	(I)	0.02325	(I)	0.02325	(I)
NONCORE IMPLEMENTATION PLAN – LT	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)
NONCORE IMPLEMENTATION PLAN – BB	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN – Storage	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.02457**	(R)	**0.27738**	(I)	**0.21539**	(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

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	0.00867	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)
NCA – DISTRIBUTION SUBACCOUNT	0.00000		0.20468	(I)	0.13375	(I)	0.11925	(I)	0.10792	(I)
CPUC FEE	0.00069		0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)
CEE INCENTIVE	0.00000		0.00017	(I)	0.00017	(I)	0.00017	(I)	0.00017	(I)
LOCAL TRANSMISSION (AT RISK)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)
NCA - ARB AB32 COI	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)
NONCORE IMPLEMENTATION PLAN – LT	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)
NONCORE IMPLEMENTATION PLAN – BB	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN – Storage	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.02826**	(R)	**0.23291**	(R)	**0.16198**	(R)	**0.14748**	(R)	**0.13615**	(R)

* 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

	G-NGV4 BACKBONE		G—NGV4-DISTRIBUTION WINTER							
THERMS:			0-20,833		20,834-49,999		50,000-166,666		166,667-249,999	
NCA – NONCORE	0.00867	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)	0.00847	(R)
NCA – DISTRIBUTION SUBACCOUNT	0.00000		0.27317	(I)	0.17741	(I)	0.15784	(I)	0.14255	(I)
CPUC FEE	0.00069		0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)	0.00126	(I)
CEE INCENTIVE	0.00000		0.00017	(I)	0.00017	(I)	0.00017	(I)	0.00017	(I)
LOCAL TRANSMISSION (AT RISK)	0.00000	(R)	0.02325	(I)	0.02325	(I)	0.02325	(I)	0.02325	(I)
NCA - ARB AB32 COI	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)	0.00056	(R)
NONCORE IMPLEMENTATION PLAN – LT	0.00000		(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)	(0.00319)	(R)
NONCORE IMPLEMENTATION PLAN – BB	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)	(0.00256)	(R)
NONCORE IMPLEMENTATION PLAN – Storage	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)	(0.00042)	(R)
TOTAL RATE	**0.00820**	(R)	**0.30140**	(I)	**0.20564**	(R)	**0.18607**	(R)	**0.17078**	(R)

* 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.)*

	G-LNG (1)*	
NCA – NONCORE	0.00000	
NCA – DISTRIBUTION SUBACCOUNT	0.00000	
CPUC Fee	0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00000	
CEE INCENTIVE	0.00000	
LNG BALANCING ACCOUNT	0.16677	(R)
LOCAL TRANSMISSION (AT RISK)	0.00000	
TOTAL RATE	**0.16746**	**(R)**

* 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	$0.30737	(I)	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	$0.12906	(I)	All Usage Levels	$4.95518
Schedule G-NGV1	$0.06772	(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	$0.14041	(I)	0 to 5,000	$2.04230	(I)
Local Transmission	$0.00892	(I)	5,001 to 10,000	$6.08351	(I)
Backbone	$0.00000		10,001 to 50,000	$11.32274	(I)
			50,001 to 200,000	$14.85962	(I)
Schedule G-EG			200,001 to 1,000,000	$21.56022	(I)
Distribution	$0.00279	(I)	1,000,001 and above	$182.88493	(I)
Local Transmission	$0.00279	(I)			
Backbone	$0.00279	(I)			
Schedule G-NGV4					
Distribution	$0.14041	(I)			
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)								1,678,109	(I)	
Pension (2)								50,422	(I)	
Less: Other Operating Revenue								(25,228)		
Authorized Distribution Revenues in Rates	1,644,014	(I)	59,289	(I)				1,703,303	(I)	
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:										
G-10 Procurement-Related Employee Discount	(1,035)	(I)						(1,035)	(I)	
G-10 Procurement Discount Allocation	408	(R)	627	(R)				1,035	(R)	
Core Brokerage Fee Credit	(6,583)							(6,583)		
Distribution Base Revenue with Adj. and Credits	1,636,804	(I)	59,916	(I)				1,696,720	(I)	
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):										
Transportation Balancing Accounts	460,313	(I)	14,787	(R)				475,100	(I)	
Self-Generation Incentive Program Revenue Requirement	2,587	(I)	3,938	(I)				6,525	(I)	
CPUC Fee	1,970		1,240					3,210		
									(D)	
									(D)	
Franchise Fees and Uncollectible Expense (F&U) (on items above)	8,742	(I)	794	(R)				9,536	(I)	
CARE Discount included in PPP Funding Requirement	(113,888)	(R)						(113,888)	(R)	
CARE Discount not included in PPP Surcharge Rates	0							0		
Transportation Forecast Period Costs & Balancing Account Balances	359,724	(I)	20,759	(R)				380,483	(I)	
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):										
Local Transmission	138,046	(I)	78,398	(I)				216,444	(I)	
Customer Access Charge – Transmission			5,127	(I)				5,127	(I)	
Storage	49,201	(I)			35,030	(I)		84,231	(I)	
Carrying Cost on PG&E Working Gas in Storage	2,414	(I)			649	(I)		3,063	(I)	
Backbone Transmission/L-401	98,132	(I)			137,996	(I)		236,128	(I)	
Gas Accord Revenue Requirement	287,793	(I)	83,525	(I)	173,675	(I)		544,993	(I)	

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(1) The amount includes the authorized distribution base revenue and F&U approved effective January 1, 2014, in GRC D.14-08-032.

(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 authorized in D.14-12-033. (T)

(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).

*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.)

	Amount ($000)					
Description	Core	Noncore	Unbundled	Core Procurement	Total	
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):						
Illustrative Gas Supply Portfolio				970,172 (R)	970,172 (R)	
Interstate and Canadian Capacity				155,602 (R)	155,602 (R)	
						(D)
F&U (on items above and Procurement Account Balances Below)				19,620 (R)	19,620 (R)	
Backbone Capacity (incl. F&U)	(67,294) (R)			67,294 (I)	0	
Backbone Volumetric (incl. F&U)	(30,838) (R)			30,838 (I)	0	
Storage (incl. F&U)	(49,201) (R)			49,201 (I)	0	
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(2,414) (R)			2,414 (I)	0	
Core Brokerage Fee (incl. F&U)				6,583	6,583	
Procurement Account Balances				- (R)	- (R)	
Illus. Core Procurement Revenue Requirement	(149,747) (R)			1,301,724 (R)	1,151,977 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**2,134,574** (I)	**164,200** (R)	**173,675** (I)	**1,301,724** (R)	**3,774,173** (I)	
IMPLEMENTATION PLAN REVENUE REQUIREMENT (7)						
Implementation Plan – Local Transmission	0 (R)	0 (R)			0 (R)	
Implementation Plan – Backbone	0 (R)	0 (R)			0 (R)	
Implementation Plan – Storage	0 (R)	0 (R)			0 (R)	
Total Implementation Plan	**0** (R)	**0** (R)			**0** (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						
Energy Efficiency (EE)	69,554 (I)	7,742 (I)			77,296 (I)	
Energy Savings Assistance (ESA)	61,961 (I)	6,897 (I)			68,858 (I)	
Research, Demonstration and Development (RD&D)	6,715 (R)	3,779 (R)			10,494 (R)	
CARE Administrative Expense	1,811 (I)	1,190 (I)			3,001 (I)	
Statewide Marketing, Education & Outreach – Phase 2	(429) (R)	(48) (R)			(477) (R)	(T)
BOE and CPUC Administrative Cost	260 (I)	146 (I)			406 (I)	
PPP Balancing Accounts	4,526 (I)	(6,266) (I)			(1,740) (I)	
CARE Discount Recovered from non-CARE customers	68,733 (I)	45,155 (I)			113,888 (I)	
Total PPP Funding Requirement in Rates	**213,131** (I)	**58,595** (I)			**271,726** (I)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**2,347,705** (I)	**222,795** (R)	**173,675** (I)	**1,301,724** (R)	**4,045,899** (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 2015 PPP surcharge AL 3528-G; and includes ESA program funding adopted in D.14-08-030, EE program funding adopted in D.14-10-046, CARE annual administrative expense adopted in D.14-08-030, and excludes F&U per D.04-08-010. (T) (T)

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030 and updated in D.14-11-023. The decrease in the total PSEP revenue requirements is incorporated in the Core Gas Pipeline Safety Balancing account (CGPSBA) and Noncore Pipeline Safety Balancing Account (NGPSBA), which are included in the Transportation Balancing Account amount shown above. (T) I (T)

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 4

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

3. COST ALLOCATION FACTORS:

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

	Factor			
Cost Category	Core	Noncore	Unbundled Storage and System Load Balancing	Total
Distribution Base Revenue Requirements	0.965192 (R)	0.034808 (I)		1.000000
Intervenor Compensation	0.965192 (R)	0.034808 (I)		1.000000
Other – Equal Distribution Based on All Transportation Volumes	0.394376 (R)	0.605624 (I)		1.000000
Carrying Cost on PG&E Working Gas in Storage	0.718750		0.281250	1.000000
ARB AB32 Cost of Implementation Fee	0.571501 (I)	0.428499 (R)		1.000000
TID – Almond Power Plant Cold Year January	0.646104	0.353896		1.000000

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

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

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

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

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

(Continued)

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

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

6. FRANCHISE FEES AND UNCOLLECTIBLE ACCOUNTS EXPENSE (F&U): F&U refers to that portion of rates designed to recover PG&E's authorized expenses for both the use of public rights-of-way (franchise fees) and bad debts (uncollectible accounts expense). Rates for retail customers include a component for F&U, as determined in PG&E's 2014 General Rate Case Decision 14-08-032. Rates for wholesale customers include a component for the franchise fees only, per Decision 87-12-039. Rates for UEG and cogeneration include uncollectibles expense and a reduced component for franchise fees.

   The F&U factor is equal to.. 1.017454 (I)

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

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

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

(Continued)

GAS SCHEDULE G-AA Sheet 2
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	$0.3475	(I)
Baja to On-System	$0.3964	(I)
Silverado to On-System	$0.1989	(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	$0.3475	(I)
Baja to Off-System	$0.3964	(I)
Silverado to Off-System	$0.3475	(I)
Mission to Off-System	$0.3475	(I)
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	$5.7105	(I)	$8.6209	(I)
Redwood to On-System (Core Procurement Groups only)	$4.9663	(I)	$7.0192	(I)
Baja to On-System	$6.5151	(I)	$9.8356	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$5.8170	(I)	$8.2215	(I)
Silverado to On-System (including Core Procurement Groups)	$3.4544	(I)	$4.8477	(I)
Mission to On-System (including Core Procurement Groups)	$3.4544	(I)	$4.8477	(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	$0.1018	(I)	$0.0061	(R)
Redwood to On-System (Core Procurement Groups only)	$0.0749	(I)	$0.0074	(R)
Baja to On-System	$0.1162	(I)	$0.0070	(R)
Baja to On-System (N) (Core procurement Groups only) (N)	$0.0878	(I)	$0.0087	(R)
Silverado to On-System (including Core Procurement Groups)	$0.0522	(I)	$0.0063	(R)
Mission to On-System (including Core Procurement Groups)	$0.0522	(I)	$0.0063	(R)
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

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	$5.7105	(I)	$8.6209	(I)
Baja to Off-System	$6.5151	(I)	$9.8356	(I)
Silverado to Off-System	$5.7105	(I)	$8.6209	(I)
Mission to Off-System	$5.7105	(I)	$8.6209	(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 Off-System	$0.1018	(I)	0.0061	(R)
Baja to Off-System	$0.1162	(I)	0.0070	(R)
Silverado to Off-System	$0.1018	(I)	0.0061	(R)
Mission to Off-System	$0.1018	(I)	0.0061	(R)

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 $0.0135 (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

Sheet 1

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	$0.1285 (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.

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* 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, 2016. 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	$2.04230	(I)
5,001 to 10,000 therms	$6.08351	(I)
10,001 to 50,000 therms	$11.32274	(I)
50,001 to 200,000 therms	$14.85962	(I)
200,001 to 1,000,000 therms	$21.56022	(I)
1,000,001 and above therms	$182.88493	(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: $0.00915 per therm (R)

   b. All Other Customers: $0.02921 per therm (R)

* 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

Sheet 1

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): .... $1.1206 (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.

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

(Continued)

GAS SCHEDULE G-LNG

Sheet 1

EXPERIMENTAL LIQUEFIED NATURAL GAS SERVICE

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):	$0.16746 (R)
LNG Gallon Equivalent: (Conversion factor - One LNG Gallon = 0.82 Therms)	$0.13732 (R)

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

Sheet 1

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	$6.1457 (I)
Withdrawal	$21.2779 (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.

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* 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	$6.1457 (I)
Inventory	$2.9366 (I)
Withdrawal/Day	$21.2779 (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.

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

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GAS SCHEDULE G-NGV4

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. <u>Customer Access Charge</u>:

   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	$2.04230	(I)
5,001 to 10,000	$6.08351	(I)
10,001 to 50,000	$11.32274	(I)
50,001 to 200,000	$14.85962	(I)
200,001 to 1,000,000	$21.56022	(I)
1,000,001 and above	$182.88493	(I)

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

(Continued)

GAS SCHEDULE G-NGV4
Sheet 2

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) .... $0.00820 (R)

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)............................... $0.02826 (R)

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	$0.23291	(R)	$0.30140	(I)
Tier 2: 20,834 to 49,999	$0.16198	(R)	$0.20564	(R)
Tier 3: 50,000 to 166,666	$0.14748	(R)	$0.18607	(R)
Tier 4: 166,667 to 249,999	$0.13615	(R)	$0.17078	(R)
Tier 5: 250,000 and above*	$0.02826	(R)	$0.02826	(R)

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	$2.04230	(I)
5,001 to 10,000	$6.08351	(I)
10,001 to 50,000	$11.32274	(I)
50,001 to 200,000	$14.85962	(I)
200,001 to 1,000,000	$21.56022	(I)
1,000,001 and above	$182.88493	(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): $0.00820 (R)

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): $0.03758 (R)

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	$0.23291	(R)	$0.30140	(I)
Tier 2: 20,834 to 49,999	$0.16198	(R)	$0.20564	(R)
Tier 3: 50,000 to 166,666	$0.14748	(R)	$0.18607	(R)
Tier 4: 166,667 to 249,999	$0.13615	(R)	$0.17078	(R)
Tier 5: 250,000 and above*	$0.03758	(R)	$0.03758	(R)

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): .... $1.1206 (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

Sheet 1

STANDARD FIRM STORAGE SERVICE

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.......... $0.2447 (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

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	$6.8526	(I)	$10.3450	(I)
Baja to On-System	$7.8182	(I)	$11.8027	(I)
Baja to On-System (N) (Core Procurement Groups only) (N)	$6.9804	(I)	$9.8658	(I)
Silverado to On-System	$4.1453	(I)	$5.8173	(I)
Mission to On-System	$4.1453	(I)	$5.8173	(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	$0.1222	(I)	$0.0074	(R)
Baja to On-System	$0.1394	(I)	$0.0084	(R)
Baja to On-System (N) (Core Procurement Groups only) (N)	$0.1053	(I)	$0.0104	(R)
Silverado to On-System	$0.0626	(I)	$0.0076	(R)
Mission to On-System	$0.0626	(I)	$0.0076	(R)

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	$160.11123	(I)
Coalinga	$48.02071	(I)
West Coast Gas-Mather	$25.49195	(I)
Island Energy	$32.53578	(I)
Alpine Natural Gas	$10.85819	(I)
West Coast Gas-Castle	$27.89523	(I)

2. Transportation Charges:

For gas delivered in the current billing month:

	Per Therm	
Palo Alto-T	$0.02457	(R)
Coalinga-T	$0.02448	(R)
West Coast Gas-Mather-T	$0.02457	(R)
West Coast-Mather-D	$0.27738	(I)
Island Energy-T	$0.02461	(R)
Alpine Natural Gas-T	$0.02444	(R)
West Coast Gas-Castle-D	$0.21539	(I)

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

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

AT&T
Albion Power Company
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
Cool Earth Solar, Inc.
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 County Integrated Waste Management Task Force
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.
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
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)
YEP Energy