Pacific Gas & Electric Company
2008 Gas Transmission & Storage Rate Case

Gas Accord IV Settlement Agreement

March 15, 2007

Subject to Rule 12 of the CPUC Rules of Practice and Procedure,
Rule 601 et seq. of the FERC Rules of Practice, Rule 408 of the Federal
Rules of Evidence, and Section 1152 of the California Evidence Code

Gas Accord IV Settlement Agreement

March 15, 2007

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Gas Accord IV
Settlement Agreement

March 15, 2007

1. Introduction

1.1. Purpose

The purpose of this Gas Accord IV Settlement Agreement ("Settlement Agreement" or "Settlement") is to resolve potential issues that would otherwise be litigated in PG&E's 2008 Gas Transmission and Storage ("GT&S") Rate Case. This Settlement and its attendant application and workpapers meet the requirement of Section 2.2.1 of the Gas Accord III Settlement Agreement, which states "PG&E will file its next rate case no later than February 9, 2007." Following a PG&E request, supported by the Settlement Parties, an extension of the filing date to March 15, 2007, was granted by the CPUC Executive Director on February 1, 2007.

1.2. Gas Accord

Under this Settlement Agreement, the basic Gas Accord structure approved in D.97-08-055 remains in place for Northern California. This includes unbundled transmission and storage services. Backbone transmission service is provided via defined paths under firm or as-available tariffs. Storage services are also offered on a firm and as-available basis. This Settlement Agreement makes certain small modifications to the existing Gas Accord provisions, as most recently modified in D.04-12-050, which approved the Gas Accord III Settlement Agreement. As in the first Gas Accord, the rates determined by this Settlement Agreement reflect a negotiated balance including, among other things, revenue requirement, backbone load factor, local transmission throughput, and firm storage capacities.

1.3. Settlement Parties

This Settlement Agreement is entered into by the Settlement Parties ("Settlement Parties" or "Parties"), as identified by their attached signatures. Parties agree to actively support approval of this Settlement Agreement in the instant application. Parties also agree to not support any changes to this Settlement Agreement that would be effective during the term of this Settlement in any regulatory, legislative or judicial forum, other than as allowed under this Settlement Agreement.

1.4. Compromise and Support

This Settlement Agreement is a negotiated compromise of issues and is broadly supported by parties who are gas producers, marketers, shippers, independent storage providers, wholesale and retail end-use customers, and regulatory representatives. Nothing contained herein shall be deemed to constitute an admission or an acceptance by any party of any fact, principle, or position contained herein. Notwithstanding the foregoing, the Settlement Parties, by signing this Settlement Agreement and by joining the Application requesting Commission approval of this Settlement Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of these provisions.

1.5. Complete Package

This Settlement Agreement is to be treated as a complete package not as a collection of separate agreements on discrete issues or proceedings. To accommodate the interests of different parties on diverse issues, the Settlement Parties acknowledge that changes, concessions, or compromises by a party or parties in one section of this Settlement Agreement necessitated changes, concessions, or compromises by other parties in other sections.

1.6. Tariffs To Implement Settlement

Simultaneously with the filing of this Settlement Agreement, PG&E is filing for Commission approval the pro forma tariff sheets that would implement the terms agreed to herein. Parties request that the Commission approve the pro forma tariff sheets at the same time it approves the Settlement Agreement, and that the tariffs and rates be effective on January 1, 2008.

1.7. Tariffs and Other Gas Accord Provisions Not Affected

Unless otherwise explicitly changed by this Settlement Agreement, all other portions of PG&E's tariffs and provisions approved in prior Commission decisions related to providing gas transmission and storage services remain in place through 2010 for transmission and through March 31, 2011 for storage, unless changed by other Commission action. This includes, among other things, the z-factor adjustment mechanism, the Catastrophic Events Memorandum Account (CEMA), the Hazardous Substance Mechanism (HSM), and the Risk Management Program and financial derivatives authorizations approved in D.03-12-061.

1.8. Modifications by Commission

In the event the Commission rejects or modifies this Settlement Agreement, the Settlement Parties reserve their rights under Rule 12.4 of the Commission's Rules of Practice and Procedure.

1.9. Implementation

Assuming a Commission decision approving this Settlement Agreement is issued before the end of 2007, tariffs to implement this Settlement will be filed in conjunction with other core and noncore rates and revenue requirement changes to be effective January 1, 2008.

2. Term of Settlement

2.1. Settlement Period

The Settlement covers three rate-case years (Settlement Period). The Settlement Period is January 1, 2008, through December 31, 2010, for transmission services, and April 1, 2008, through March 31, 2011, for storage services.

2.2. Effective Date

The effective date of this Settlement Agreement shall be the later of January 1, 2008, or the effective date of the tariffs approved by the Commission to implement the Settlement.

2.3. Next Rate Case Filing

2.3.1. The Settlement Parties expect that PG&E will file its next rate case no later than Monday, February 1, 2010. For good cause shown, PG&E may request that the Commission approve an extension of this filing date. The non-PG&E parties reserve the right to object to such request for an extension.

2.3.2. Interim Rates

Should approved rates not be in place for Gas Transmission and Storage (GT&S) services by January 1, 2011, pursuant to a Commission order in this next rate case, the interim transmission and storage rates will equal the rates in effect on December 31, 2010, plus a two (2) percent escalator for Local Transmission rates and other adjustments authorized by this Settlement. Rates for Backbone, Storage and Customer Access Charge will remain the same, except as otherwise provided in this Settlement. G-XF rates will continue to be calculated based on Line 401 incremental costs. Such Interim Rates will remain in effect until the Commission otherwise approves rates for the remainder of 2011.

3. Backbone Transmission Services

The path structure and backbone services remain the same. All gas transported using PG&E's backbone service must eventually be delivered to an on-system end user, except for backbone level end-use service, or wholesale customer using local transmission service, or to an off-system customer or delivery point.

3.1. Backbone Capacity and Average Gas Heating Value

PG&E's firm backbone capacity for the Redwood and Baja paths are shown in Appendix A, Table A-1. Recently, the firm annual receipt capacity available on the Baja path has decreased to 1,073 MMcf/d from 1,140 MMcf/d. This reduction is caused by the combination of reduced off-system flows to Southern California and the reduced capacity of the Kettleman compressor station when it was rebuilt in 2001.

Additionally, the average heating value of the gas moving on the backbone system has increased to 1,020 Btu/cubic foot from 1,015 Btu/cubic foot. This changes the delivered firm capacity, which is also shown in Table A-1.

3.2. Wholesale Core Customer Option for Vintage Redwood Capacity

The Vintage Redwood capacity of 615.6 MDth/d (firm delivery capacity) set aside for PG&E's Core Gas Supply ("CGS")[1] and existing wholesale core customers is not changed. The allocation of this capacity to these customers remains the same as per the Gas Accord III Settlement Agreement, Appendix A, Table A-2. Existing wholesale customers will have a one-time option prior to April 1, 2008, to subscribe to their allocation of Vintage Core Redwood firm capacity for the Settlement Period at the same rate paid by CGS.

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1 Previously referred to as PG&E's Core Procurement Department.

3.3. CGS's Allocation of Backbone Capacity

PG&E will file a separate expedited application to obtain Commission approval of changes in CGS's firm backbone capacity allocations from those approved in prior Commission decisions and reflected in the Gas Accord III Settlement. This separate filing is a one-time requirement agreed to as part of this Settlement, and does not limit CGS's future procedural options for seeking additional changes to its firm backbone allocations.

3.4. Backbone Level End-Use Service

Backbone Level End-Use Service was approved by the Commission in D.03-12-061. The specific eligibility requirements were specified and implemented as part of the Gas Accord III Settlement, and are listed in PG&E's gas Rule 1. These requirements, as amended by this Settlement Agreement, will continue for the Settlement Period. Customers qualifying for this service do not pay the local transmission rate component as specified in the otherwise applicable end-use tariff. However, they continue to be responsible for all other rate components in their end-user tariffs to the extent they are not components of local transmission service.

3.4.1. Eligibility Opportunity for PG&E Exchange Service Customers

An Exchange Service customer is a PG&E customer that uses the pipeline of an Independent Storage Provider ("ISP") to connect the customer's facility to the PG&E transmission system. Exchange Service was established by the ISP Interconnections Settlement Agreement that was approved by the Commission in D.06-09-039.

If the PG&E Exchange Service customer is connected to an ISP pipeline that in turn is connected directly to PG&E's backbone system, then that customer will have the opportunity to qualify for PG&E Backbone Level End-Use Service under rate Schedule G-NT or G-EG. To be eligible, the customer must meet all other existing eligibility requirements for this service. The Rule 1 criteria will be modified by adding Section 5.c stating:

> "c. Owned by an Independent Storage Provider connected to a PG&E Exchange Service End-Use Customer, which with respect to Wild Goose Storage LLC, includes all of their Commission-approved facilities that existed as of January 1, 2007."

Except as provided in the paragraph c, above, if the ISP pipeline to which the Exchange Service customer is connected, is in turn only connected to PG&E's local transmission system, then that customer does not have the opportunity to qualify for Backbone Level End-Use Service.

3.4.2. Eligibility Opportunity for Moss Landing Power Plant Units 1 and 2

The owner of Moss Landing Power Plant Units 1 and 2 is given the opportunity to connect to a PG&E Backbone Transmission line as defined in Rule 1. This connection would only be for service to these two brownfield units that went into operation in mid-2002. To accommodate this single exception, the Rule 1 criteria for a Backbone Level End-Use Customer will be revised as follows (change in double underline).

"4. Has never been physically connected to PG&E's local transmission or distribution system, except that Moss Landing Power Plant Units 1 & 2 are not required to meet this criterion to qualify as a Backbone Level End-Use Customer; and"

3.4.3. Balancing Account for Changes to Customers Qualifying for Backbone Level End-Use Service

PG&E will continue to track the change in local transmission demand arising from any changes to the customers that are identified as eligible for backbone level end-use service as of the date of a Commission order approving this Settlement. PG&E will record the revenue debit or credit entry based on the customer's actual annual demand multiplied by the applicable local transmission rate in effect, for each customer identified as a change. The tracked amount will be allocated to the Core Fixed Cost Account and the Noncore Customer Class Charge Account in the same proportion as local transmission costs are allocated between core and noncore customers, respectively, and will be reflected in rates in the Annual Gas True-Up of Balancing Account filings (Annual Gas True-Up). This treatment does not apply to new customers or, during the term of this Settlement, to customers who become eligible for Backbone Level Service as a result of Sections 3.4.1 or 3.4.2.

3.5. No Open Season for Firm Backbone Capacity

PG&E will not hold an open season for existing firm backbone capacity at the beginning of the Settlement Period. Sufficient firm backbone capacity remains available for any customer desiring this service at this time.

4. Local Transmission Service

There are no changes to how local transmission service is provided. Local transmission service continues to be non-bypassable for all on-system end-use and wholesale customers taking service from PG&E, except for customers qualifying for Backbone Level End-Use Service.

5. Storage Services

The storage services and assignments of firm storage to PG&E's Core Gas Supply, pipeline balancing and noncore storage remain the same as Gas Accord III.

5.1. No Open Season for Firm Storage Capacity

PG&E will not hold an open season for existing firm storage capacity at the beginning of the Settlement Period.

5.2. Sale of Noncycle Working Gas

PG&E retains the right during the Settlement Period to file a Section 851 application to sell noncycle working gas in order to expand its annual ability to cycle storage on behalf of its storage customers. Settlement Parties retain the right to take any position regarding such application.

6. Customer Access Charge (CAC)

The rate design for the Customer Access Charge may be addressed in PG&E's Biennial Cost Allocation Proceedings (BCAPs). However, during the term of this Settlement, any changes to the CAC rate design will be based on the CAC revenue requirement specified in this Settlement.

7. PG&E Authority to Negotiate Rate Discounts

Nothing in this Settlement alters PG&E's existing authority to negotiate rate discounts for backbone transmission service, storage services or for bundled end-use services. PG&E is willing to negotiate discounts to these services with customers that have competitive alternatives or under other circumstances that PG&E determines justify such discounts.

Also, nothing in this Settlement Agreement shall modify existing negotiated agreements between PG&E and any end-use customer or other shipper.

8. Revenue Requirements, Rates and Accounting

8.1. Revenue Requirement Escalators

The revenue requirements over the Settlement Period are based on the negotiated annual escalators shown below, which are applied to the approved Gas Accord III 2007 revenue requirements for each function. However, the rate Schedule G-XF revenue requirement and rate will continue to be calculated based on the forecast of Line 401 costs, as required by those contracts.

Revenue Requirement Escalators by Function

Line No.	Function	2008	2009	2010
1	Backbone Transmission (excluding Schedule G-XF)	-1%	-1%	-1%
2	Local Transmission without Designated Projects (see Section 8.4, below)	+4%	+2%	+2%
3	Core Storage	0%	0%	0%
4	Customer Access Charge	0%	0%	0%

8.2. Backbone Rate Escalators

The rates for Backbone Transmission Annual Firm services are based on the following negotiated escalators. These are designed based on (a) the declining revenue requirement for Backbone Transmission described in Section 8.1, (b) a 76.5 percent backbone load factor agreed to for 2007 (the same as that agreed to in the Gas Accord III Settlement), (c) setting the Baja path rate $0.025 per dth higher than the Redwood noncore path rate, and (d) assuring that the total CGS revenue responsibility, based on their backbone firm capacity holdings, declines at

-1 percent each year.[2] The backbone rate surcharge specified in Section 8.5, below, is additive to the backbone rates after the escalators are applied.

Backbone Path Rate Escalators

Line No.	On-System Backbone Service	2008	2009	2010
1	Redwood Path – Core Vintage	-9.6%	-1%	-1%
2	Redwood Path – Noncore	-4.4%	-1%	-1%
3	Baja Path – All	+5.8%	-1%	-1%
4	Silverado Path	-1%	-1%	-1%
5	Mission Path	-1%	-1%	-1%

The Seasonal Firm, As-Available rates, and Off-System rates continue to be derived from the Annual Firm On-System rates based on the same prior Gas Accord methodologies.

8.3. Local Transmission, Storage and CAC Rate Escalators

The rates for Local Transmission (LT) services equal the Gas Accord III Settlement 2007 Local Transmission rates escalated using the LT revenue requirement escalator, subject to the rate adders for the specific LT capital projects designated in Section 8.4, below. The rates for Storage Services and Customer Access Charge remain at the Gas Accord III Settlement 2007 level, except that the CAC rates may change pursuant to Section 6.1, above.

8.4. Adjustments for Designated Local Transmission Capital Projects

There are several large local transmission capital projects whose timing of operation and scope may change. In order to more accurately reflect the actual timing, these projects are not included in the local transmission revenue requirements or rates agreed to in this Settlement. Appendix A, Table A-2 lists the projects and their respective revenue requirement and rate adders, subject to modification as provided in Sections 8.4.2 and 8.4.3 below. On January 1, following the operational date for each project, PG&E will increase the adopted local transmission revenue requirements and rates, as provided below. PG&E assumes the risk of changes in the capital costs and other factors that would otherwise result in different revenue requirement and rate adjustments during the Settlement Period.

8.4.1. LT Capital Project Adjustment Mechanism

The specified local transmission revenue requirement and rate adjustment for each designated capital project will occur on January 1 of the year following the operational date of the project. These adjustments to the adopted local

[2] These calculations are based on an increase in CGS's Annual Baja holdings and a corresponding decrease in their seasonal Baja holdings. Approval of this change will be sought in a separate application as provided in Section 3.3, above. Should this adjustment to their holdings not be approved, then Backbone Rates will be recalculated based on the same principles, but using the CGS's Backbone firm capacity allocations from the Gas Accord III Settlement or as otherwise authorized by the Commission.

transmission revenue requirements and rates will be incorporated into the Annual Gas True-Up. During the term of this Settlement, the Settlement Parties will not protest these LT capital project adjustments. The non-PG&E Settlement Parties reserve their right in future rate cases to address the reasonableness, including the costs, of these LT projects. No other local transmission capital project will be allowed such an adjustment during the Settlement Period.

If a designated project becomes operational in 2010, then the 2010 adjustments will be applied effective January 1, 2011, if the Commission has not otherwise approved rates based on the next GT&S Rate Case that would be effective on January 1, 2011. This is in addition to any rate adjustments provided by Section 2.3.2.

8.4.2. Line 406 and Line 407 Project Workshops

PG&E will hold workshops to determine if there are any synergies with Sacramento Municipal Utility District (SMUD) or a local storage project that could reduce or defer PG&E's investments in either the Line 406 or Line 407 projects. These workshops will be held pursuant to the Commission's Settlement Rule 12. A determination and confirmation of such synergies will be made by June 1, 2007, and will be documented as a contractual term sheet between PG&E and the third-party operator. Any arrangements between PG&E and a third-party operator must provide a level of service consistent with PG&E's planning standards for its local transmission systems. A contract(s) with the third-party operator(s) must be signed no later than August 15, 2007, in order for PG&E to adjust its project engineering, cost estimates and materials acquisition schedule. PG&E will then provide revised project costs and local transmission revenue requirement and rate adders for the Line 406 or Line 407 projects, as applicable, to all the Settlement Parties based on these contractual arrangements. These adders would include the costs that PG&E may be paying the third-party operator for their services.

If arrangements are made and service contracts are signed with SMUD or a storage facility, then PG&E will file an update to the Settlement Agreement to reflect the reduced adder(s) for the affected project(s) and will include a copy of the contract(s) with its filing.

8.4.3. Meet and Confer

Should there be a material change in the scope of one of the designated LT projects, PG&E agrees to meet and confer with the Settlement Parties and attempt, in good faith, to arrive at a mutually agreeable decrease in the applicable LT adder to reflect the change in scope. This meet and confer provision also will apply to the Line 406 and Line 407 projects, should PG&E and parties not be able to reach an agreement through the workshop process within the time frame specified, unless otherwise agreed. All meet and confer discussions under this paragraph will be held pursuant to CPUC Rule 12.

When the LT adders for a revised project are ready to be implemented on January 1 following its operational date, the modified adders will be used in place of those specified in the Settlement as approved by the Commission.

8.5. Local Transmission Bill Credits and Revenue Responsibility

Moss Landing Power Plant Units 1 and 2 will receive a monthly credit to their local transmission bill of $2 million per year increased at the base LT revenue requirement escalator over the Settlement Period. Four members of the Northern California Generation Coalition (NCGC) will split equally a total local transmission bill credit of $200,000 in 2008, escalated at the base LT escalator for 2009 and 2010. The four members are the City of Redding, Modesto Irrigation District, Turlock Irrigation District and City of Santa Clara (Silicon Valley Power). They each own combined cycle gas turbine electric power plants. The bill credits are effective with the implementation of the local transmission rates for the duration of the Settlement Period. The bill credits will be applied monthly in the amounts shown in Appendix A, Table A-3.

The revenue responsibility for a portion of the bill credits will be collected through PG&E's rates as two volumetric surcharges – one is applicable to all backbone customers and recovered through backbone rates, and the other is applicable just to Backbone Level End-Use Customers and recovered through G-EG and G-NT rates. These volumetric surcharges are shown on Appendix A, Table A-3.

8.6. Revenue Requirement and Rate Tables

The revenue requirements agreed to in this Settlement are shown in Appendix A, Table A-4. Illustrative class average rates are shown in Appendix B, Tables 1 and 2. For noncore retail and wholesale customers, the rates reflect the impacts of the local transmission and customer access charges agreed to in this Settlement. For bundled core customers, the rates reflect the impacts of the local transmission, storage and intrastate backbone charges agreed to in this Settlement. For core transport customers, the rates reflect the impacts of the local transmission rates agreed to in this Settlement.

Appendix B, Tables 3 through 9, show the backbone rates by service and rate design. Storage rates are shown in Appendix B, Table 10. Local transmission rates are shown in Appendix B, Table 11. Customer Access Charges are shown in Appendix B, Table 12. If a customer elects to self-balance pursuant to Rate Schedule G-BAL, such customer receives a credit as shown in Appendix B, Table 13.

All rate changes will be effective January 1 of each year, including storage rates. Therefore, although storage services will be authorized by this Settlement through March 31, 2011, the storage rates for the first three months of 2011 will be set in the next rate case.

8.7. Depreciation Rates

During the term of this Settlement, PG&E will continue to use the depreciation parameters used in the Gas Accord III Settlement and approved in D.04-12-050.

8.8. Cost Accounting Change

The cost accounting for the Pipeline Integrity Management Program will be revised so that beginning January 1, 2008, the costs for the first in-line inspection tool runs will be expensed, rather than capitalized. On June 30, 2005, the Federal Energy Regulatory Commission (FERC) provided this accounting guidance for interstate pipelines. Although the CPUC and its jurisdictional utilities are not bound by FERC accounting rules, they generally follow them. While the costs for the initial in-line inspection tool run will be expensed beginning on January 1, 2008, all other expenditures within the Internal Line Inspection program that are currently capitalized will continue to be capitalized.

9. Other Provisions

9.1. Operational Provisions

9.1.1. PG&E will form a Diversion and Curtailment Working Group to explore alternatives and/or clarifications to PG&E's current rules relating to a system supply diversion or to a local transmission curtailment. These events are driven by supply shortages and/or by very cold weather, usually over several days. Although these events are infrequent, some Parties are concerned that the current rules and mechanisms for managing such crisis events may not properly reflect current policies, especially those related to the operation of gas-fired electric generation. The Working Group will explore this and other related diversion and curtailment issues raised by participants in the Working Group.

9.1.2. Other operational issues may arise that need to be addressed during the term of the Settlement Agreement. The OFO Forum that was established under the OFO Settlement approved in D.00-02-050 is an available mechanism to discuss and resolve most other operational issues.

9.1.3. This Settlement Agreement does not preclude the ability of the Diversion and Curtailment Working Group, the OFO Forum participants, PG&E and/or any other party from bringing operational issues and solutions to the Commission for its review and approval during the term of this Settlement. Also, any Settlement Party or other party is free to respond as it deems appropriate should any operational issues and solutions be submitted to the Commission.

9.2. Core Brokerage Fee

The Core Brokerage Fee is set at $0.032 per decatherm for the term of this Settlement. The level of this fee following the Settlement Period will be litigated and decided in BCAPs, and not in GT&S rate cases.

9.3. Core Procurement Incentive Mechanism (CPIM)

Extension of the CPIM will no longer be considered in GT&S rate cases. PG&E, DRA, TURN and Aglet entered into a settlement agreement in PG&E's Long Term Core Hedge Program Application 06-05-007 ("Hedging Settlement") that was filed with the Commission on December 20, 2006. The Hedging Settlement provides in Section 6.1.10 that "the CPIM will continue indefinitely until modified or terminated by the Commission." Should that provision of the Hedging Settlement not be approved, Parties to this Gas Accord IV Settlement Agreement agree to the same provision, namely, that the CPIM will continue indefinitely until modified or terminated by the Commission.

9.4. Report on the Line 57C Project

In Decision 07-01-014, Conclusion of Law 5, the Commission finds that "PG&E is constructing Pipeline 57C for the 'solely necessary' purpose of meeting its Commission-ordered obligation to serve …." However, Ordering Paragraph 5 still requires the Commission to review and consider the following three areas.

(a) Reasonableness of the design, planning and execution of the project,

(b) Ratesetting for those components of the project found to be reasonable, and

(c) Whether operational criteria should be imposed so that reliability is ensured and system operation remains consistent with the Commission's overall policy goals for gas transmission and storage.

In compliance with that Order, PG&E is filing a Report on the Line 57C Project ("Line 57C Report") as part of the instant application requesting approval of this Gas Accord IV Settlement Agreement. Parties agree that PG&E filed this Report in compliance with Decision 07-01-014, and Parties agree not to object to the content and conclusions of the Line 57C Report.

9.5. Report on Additional Storage Capacity for Pipeline Balancing Service ("Storage for Balancing Report")

PG&E is filing its Storage for Balancing Report as part of this instant Application. This report is required by Section 4.3 of the Gas Accord III Settlement Agreement. The basis for this report stems from D.03-12-061, which approved PG&E's request to increase the amount of storage allocated to the pipeline balancing service. That decision also required PG&E to monitor and report on the effect of this additional capacity on the balancing service. Parties agree that the Storage for Balancing Report meets the Commission's requirements and agree with the conclusions of that report.

10. Rate Certainty and Adjustments During Term of Settlement

10.1. Rate Certainty

The rates specified in this Settlement Agreement are not subject to adjustment during the Settlement Period except as provided herein, or as agreed to by the Settlement Parties and approved by the Commission.

Nothing in this Settlement Agreement shall prevent PG&E from making adjustments to services, capacity assignments, cost allocations, rates or the like in order to comply with Commission orders in other proceedings. However, during the Settlement Period, no changes will be made to reflect changes in PG&E's authorized cost of capital as approved by the Commission from time to time. No Settlement Party shall make any proposal that would conflict with or alter any term of this Settlement Agreement, and the Settlement Parties shall not support proposals of others that would do the same.

10.2. BCAP, Annual Gas True-Up, Gas Public Purpose Program Surcharge and Other Filings

Certain end-use customer charges will continue to change during the Settlement Period. These include the distribution rate, the CPUC fee, mandated social program costs (such as the Self Generation Incentive Program), various balancing accounts, and the gas public purpose program surcharge. Such changes occur through Commission decisions and approvals in PG&E's BCAP, Annual Gas True-Up, and other filings. This Settlement Agreement does not change these procedures and filings.

APPENDIX A
Tables Supporting the Settlement

Table A-1
Firm Backbone Capacity

Line No.		Receipt MMcf/d	Heating Value MDth/MMcf	Shrinkage Percent	Delivery MDth/d
1	Redwood	2,020.857	1.020	1.20%	2,036.539
2	Baja	1,073.000	1.020	1.20%	1,081.326

Note: Delivery Capacity = Receipt Capacity * Heating Value * (1-Shrinkage %)

Table A-2
Local Transmission Projects
Subject to Revenue Requirement and Rate Adder Mechanism

Line No.		Estimated Capital	Local Transmission Revenue Requirement Adder, $ (000) per year					
			Core		Noncore		Total	
1	Project (Planned Operation Date)	$ million	2009	2010	2009	2010	2009	2010
2	Line 138, 16 miles 30" pipe, Fresno area (November 2008)	$38.6	$3,926	$5,375	$1,680	$2,300	$5,606	$7,675
3	Line 108, 11 miles 24" pipe, Sacramento area (November 2008)	$33.0	$4,465	$4,726	$1,911	$2,023	$6,375	$6,749
4	Line 406, 15 miles 30" pipe, Sacramento area (October 2009)	$43.1	----	$3,583	----	$1,533	----	$5,117
5	Line 407, 4 miles 30" pipe, Sacramento area (October 2009)	$11.5	----	$954	----	$408	----	$1,362
6	Line 407, 8 miles 30" pipe, Sacramento area (October 2009)	$25.8	----	$2,143	----	$917	----	$3,060
7	Total	$151.9	$8,391	$16,781	$3,591	$7,182	$11,981	$23,963

		Local Transmission Rate Adder, $ per Dth			
8		Core		Noncore	
9	Project	2009	2010	2009	2010
10	Line 138, 16 miles 30" pipe	$0.0126	$0.0173	$0.0055	$0.0075
11	Line 108, 11 miles 24" pipe	$0.0143	$0.0152	$0.0062	$0.0066
12	Line 406, 15 miles 30" pipe	----	$0.0115	----	$0.0050
13	Line 407, 4 miles 30" pipe	----	$0.0030	----	$0.0013
14	Line 407, 8 miles 30" pipe	----	$0.0068	----	$0.0029
15	Total	$0.0269	$0.0538	$0.0117	$0.0233

Table A-3
Local Transmission Bill Credits and Revenue Responsibility

Line No.		GA III 2007	2008	2009	2010
1	Moss Landing Units 1 & 2 Local Transmission Bill Credit				
2	Annual, $000	$2,000	$2,080	$2,122	$2,164
3	Monthly, $	$166,667	$173,333	$176,800	$180,336
4	City of Redding Local Transmission Bill Credit				
5	Annual, $000		$50	$51	$52
6	Monthly, $		$4,167	$4,250	$4,335
7	Modesto Irrigation District Local Transmission Bill Credit				
8	Annual, $000		$50	$51	$52
9	Monthly, $		$4,167	$4,250	$4,335
10	Turlock Irrigation District Local Transmission Bill Credit				
11	Annual, $000		$50	$51	$52
12	Monthly, $		$4,167	$4,250	$4,335
13	City of Santa Clara Local Transmission Bill Credit				
14	Annual, $000		$50	$51	$52
15	Monthly, $		$4,167	$4,250	$4,335
16	Total NCGC Member Transmission Bill Credit				
17	Annual, $000		$200	$204	$208
18	**Total Local Transmission Bill Credit**				
19	Annual, $000	$2,000	$2,280	$2,326	$2,372
20	Revenue Recovered Through Surcharge From All Backbone Shippers				
21	Responsibity for Moss Landing 1&2, $000	$2,000	$1,560	$1,591	$1,623
22	Surcharge Rate, $ per Dth	$0.0030	$0.0024	$0.0024	$0.0024
23	Revenue Recovered Through Surcharge From Backbone Level Customers (G-EG & G-NT)				
24	Responsibility for Moss Landing 1&2		$520	$530	$541
25	Responsibility for NCGC		$100	$102	$104
26	Total Revenue Responsibility, $000		$620	$632	$645
27	Surcharge Rate, $ per Dth		$0.0070	$0.0058	$0.0053
28	**Total Revenue Responsibility From Surcharges (a)**				
	Annual, $000		$2,180	$2,224	$2,268

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

Table A-4
Revenue Requirement Allocation
Between Core and Noncore Customers
($ thousand)

Line No.		Present 2007	Gas Accord IV Settlement 2008	2009	2010	% Change Over Prior Year 2008	2009	2010
	Core Revenue Requirements							
1	Existing Backbone Transmission	$ 77,441	$ 70,657	$ 69,943	$ 69,263	-8.8%	-1.0%	-1.0%
2	Net Change in Backbone Capacity	-	11,360	11,245	11,131		-1.0%	-1.0%
3	Subtotal Backbone (1)	77,441	82,016	81,189	80,394	5.9%	-1.0%	-1.0%
4	Local Transmission Base	96,812	100,685	102,698	104,752	4.0%	2.0%	2.0%
5	Local Transmission Adder	-	-	8,391	16,782			
6	Storage	43,850	43,850	43,850	43,850	0.0%	0.0%	0.0%
7	Customer Access Charge	-	-	-	-			
8	Total Core	$ 218,104	$ 226,551	$ 236,128	$ 245,779	3.9%	4.2%	4.1%
	Noncore / Unbundled Revenue Requirements							
9	Backbone Trans. w/o G-XF Contracts	$ 163,684	$ 156,697	$ 155,138	$ 153,569	-4.3%	-1.0%	-1.0%
10	G-XF Contracts	7,551	7,237	7,150	7,024	-4.2%	-1.2%	-1.8%
11	Subtotal Backbone Transmission	171,235	163,935	162,288	160,593	-4.3%	-1.0%	-1.0%
12	Local Transmission Base	41,426	43,083	43,945	44,823	4.0%	2.0%	2.0%
13	Local Transmission Adder	-	-	3,590	7,181			
14	Storage	7,750	7,750	7,750	7,750	0.0%	0.0%	0.0%
15	Customer Access Charge	5,174	5,174	5,174	5,174	0.0%	0.0%	0.0%
16	Total Noncore / Unbundled	$ 225,584	$ 219,941	$ 222,747	$ 225,521	-2.5%	1.3%	1.2%
	Total Revenue Requirements							
17	Backbone Trans. w/o G-XF Contracts	$ 241,125	$ 238,714	$ 236,327	$ 233,963	-1.0%	-1.0%	-1.0%
18	G-XF Contracts	7,551	7,237	7,150	7,024	-4.2%	-1.2%	-1.8%
19	Subtotal Backbone Transmission	248,676	245,951	243,477	240,987	-1.1%	-1.0%	-1.0%
20	Local Transmission Base	138,238	143,768	146,643	149,576	4.0%	2.0%	2.0%
21	Local Transmission Adder	-	-	11,981	23,963			
22	Storage (2)	51,600	51,600	51,600	51,600	0.0%	0.0%	0.0%
23	Customer Access Charge	5,174	5,174	5,174	5,174	0.0%	0.0%	0.0%
24	Total GT&S	$ 443,688	$ 446,493	$ 458,875	$ 471,299	0.6%	2.8%	2.7%

(1) 2008-2010 Core Backbone revenue responsibility assumes an average 76.5% load factor and includes the core's share of the local transmission bill credits as presented in Appendix A, Table A-3. Beginning in 2008, Core proposes to increase its annual Baja capacity holdings, and decrease its annual Silverado and seasonal Baja capacity holdings.

(2) 2007-2010 storage revenue requirements include the carrying costs on noncycled working gas and cycle gas.

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

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APPENDIX B

Detailed Rate Tables

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Table 1
Illustrative End-Use Class Average Rates ($/dth) (a)

	Present Rates 2007	Settlement Rates 2008	% Change
Core Retail Bundled Service (b)			
Residential Non-CARE	13.754	13.827	0.5%
Small Commercial	12.539	12.609	0.6%
Large Commercial	10.095	10.154	0.6%
Core Retail Transport Only (c)			
Residential Non-CARE	4.692	4.704	0.3%
Small Commercial	3.556	3.568	0.4%
Large Commercial	1.462	1.474	0.9%
Noncore Retail Transportation Only (c)			
Industrial - Distribution	1.311	1.316	0.4%
Industrial - Transmission	0.473	0.478	1.1%
Industrial - Backbone	0.292	0.299	2.4%
Electric Generation - Distribution/Transmission	0.244	0.249	2.2%
Electric Generation - Backbone	0.110	0.116	6.4%
Wholesale Transportation Only (c)			
Alpine Natural Gas	0.296	0.302	1.8%
Coalinga	0.288	0.294	1.9%
Island Energy	0.495	0.500	1.1%
Palo Alto	0.221	0.226	2.4%
West Coast Gas - Castle	0.684	0.689	0.8%
West Coast Gas - Mather D	0.543	0.548	1.0%
West Coast Gas - Mather T	0.297	0.302	1.8%

Notes:

a) Present 2007 rates are based on PG&E's 2007 Annual Gas True-Up Filing (Advice Letter 2780-G & 2780-G-A), 2004 BCAP Decision D. 05-06-029 and the Gas Accord III D.04-12-050.

b) PG&E's bundled gas service is for core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding, are included in end use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, transportation on Canadian and Interstate pipelines, and core brokerage. An illustrative annual 2007 weighted average cost of gas (WACOG) of $7.69 as filed in Advice Letter 2780-G/2780-G-A, adjusted for intrastate backbone usage charges, is assumed in all present and proposed bundled core rates. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

c) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

d) Actual transportation rates will vary depending on the customer's load factor and seasonal usage. The rates shown here are averages for each class.

e) Dollar difference are due to rounding.

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Table 2
2008 Rate Detail By End-Use Customer Class, Including Illustrative Components, ($/dth)

	Core (a)			Noncore Transportation				
				Industrial			Electric Gen	
	Res	Small Comm	Large Comm	Dist	Trans	BB	D/T	BB
End-Use Transportation:								
Local Transmission & LT Rate Adder	0.323	0.323	0.323	0.140	0.140	0.000	0.140	0.000
Backbone Level End-Use Surcharge						0.007		0.007
Distribution (b)	3.664	2.082	0.604	0.808	0.047	0.000	0.016	0.016
Mandated Customer Programs and Other Charges:								
Self Generation Incentive Program	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008
CPUC Fee	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007
Balancing Accounts	0.315	0.319	0.065	0.056	0.069	0.070	0.069	0.069
Volumetric End-Use Rate	4.318	2.741	1.008	1.020	0.271	0.092	0.240	0.107
Customer/ Customer Access Charge (c)	0.000	0.539	0.048	0.078	0.021	0.021	0.009	0.009
Total End-Use Rate	4.318	3.280	1.056	1.098	0.293	0.114	0.249	0.116
Gas Public Purpose Program Surcharge	0.386	0.289	0.419	0.218	0.185	0.185	0.000	0.000
Total Rate	4.704	3.568	1.474	1.316	0.478	0.299	0.249	0.116

Procurement Charges for Bundled Core Customers:			
Storage	0.1505	0.142	0.091
Backbone Capacity	0.2187	0.201	0.108
Backbone Usage	0.083	0.083	0.083
WACOG (d)	7.616	7.616	7.616
Interstate Capacity and Other	1.055	0.999	0.781
Total Core Procurement	9.1225	9.041	8.679
Total Core Bundled Rates	13.827	12.609	10.154

	Wholesale Transportation						
End-Use Transportation:	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
Local Transmission & LT Rate Adder	0.140	0.140	0.140	0.140	0.140	0.140	0.140
Backbone Level End-Use Surcharge							
Distribution (b)	0.000	0.000	0.000	0.000	0.180	0.248	0.000
Mandated Customer Programs and Other Charges:							
Self Generation Incentive Program	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CPUC Fee	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Balancing Accounts	0.069	0.069	0.069	0.069	0.066	0.066	0.069
Volumetric End-Use Rate	0.209	0.209	0.209	0.209	0.386	0.455	0.209
Customer/ Customer Access Charge (c)	0.093	0.085	0.291	0.017	0.303	0.093	0.093
Total End-Use Rate	0.302	0.294	0.500	0.226	0.689	0.548	0.302

Notes:

a) Class average rates reflect load shape for bundled core.

b) Distribution rates represent the annual class average.

c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

d) Reflects the annual average 2007 WACOG of $7.69/dth as filed in Advice Letter 2780-G/2780-G-A, adjusted for intrastate backbone usage charges.

e) Dollar difference are due to rounding.

Table 3
Firm Backbone Transportation
Annual Rates (AFT) – SFV Rate Design
On-System Transportation Service

		GA III 2007	2008	2009	2010
Redwood - Core					
Reservation Charge	($/dth/mo)	4.897	4.425	4.379	4.337
Usage Charge	($/dth)	0.014	0.013	0.013	0.012
Total	($/dth @ Full Contract)	0.175	0.158	0.157	0.155
Redwood Path					
Reservation Charge	($/dth/mo)	9.323	8.910	8.820	8.733
Usage Charge	($/dth)	0.008	0.007	0.007	0.007
Total	($/dth @ Full Contract)	0.314	0.300	0.297	0.294
Baja Path					
Reservation Charge	($/dth/mo)	8.905	9.419	9.325	9.232
Usage Charge	($/dth)	0.015	0.016	0.015	0.015
Total	($/dth @ Full Contract)	0.308	0.325	0.322	0.319
Silverado and Mission Paths					
Reservation Charge	($/dth/mo)	4.620	4.574	4.528	4.483
Usage Charge	($/dth)	0.007	0.006	0.006	0.006
Total	($/dth @ Full Contract)	0.158	0.156	0.155	0.153

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 76.5 percent load factor.

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) Dollar difference are due to rounding.

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Table 4

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

		GA III 2007	2008	2009	2010
Redwood - Core					
Reservation Charge	($/dth/mo)	3.759	3.397	3.362	3.329
Usage Charge	($/dth)	0.052	0.046	0.046	0.046
Total	($/dth @ Full Contract)	0.175	0.158	0.157	0.155
Redwood Path					
Reservation Charge	($/dth/mo)	5.413	5.173	5.120	5.070
Usage Charge	($/dth)	0.136	0.130	0.129	0.127
Total	($/dth @ Full Contract)	0.314	0.300	0.297	0.294
Baja Path					
Reservation Charge	($/dth/mo)	6.756	7.145	7.075	7.004
Usage Charge	($/dth)	0.086	0.090	0.089	0.089
Total	($/dth @ Full Contract)	0.308	0.325	0.322	0.319
Silverado and Mission Paths					
Reservation Charge	($/dth/mo)	3.178	3.147	3.115	3.084
Usage Charge	($/dth)	0.054	0.053	0.052	0.052
Total	($/dth @ Full Contract)	0.158	0.156	0.155	0.153

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 76.5 percent load factor.

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) Dollar difference are due to rounding.

Table 5
Firm Backbone Transportation
Seasonal Rates (SFT) – SFV Rate Design
On-System Transportation Service

		GA III 2007	2008	2009	2010
Redwood Path					
Reservation Charge	($/dth/mo)	11.187	10.692	10.584	10.480
Usage Charge	($/dth)	0.009	0.008	0.008	0.008
Total	($/dth @ Full Contract)	0.377	0.360	0.356	0.353
Baja Path					
Reservation Charge	($/dth/mo)	10.686	11.302	11.190	11.078
Usage Charge	($/dth)	0.019	0.019	0.019	0.018
Total	($/dth @ Full Contract)	0.370	0.390	0.386	0.383
Silverado Path					
Reservation Charge	($/dth/mo)	5.544	5.489	5.434	5.379
Usage Charge	($/dth)	0.008	0.007	0.007	0.007
Total	($/dth @ Full Contract)	0.190	0.188	0.186	0.184

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 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.

Table 6
Firm Backbone Transportation
Seasonal Rates (SFT) – MFV Rate Design
On-System Transportation Service

		GA III 2007	2008	2009	2010
Redwood Path					
Reservation Charge	($/dth/mo)	6.495	6.207	6.145	6.084
Usage Charge	($/dth)	0.164	0.156	0.154	0.153
Total	($/dth @ Full Contract)	0.377	0.360	0.356	0.353
Baja Path					
Reservation Charge	($/dth/mo)	8.107	8.574	8.489	8.404
Usage Charge	($/dth)	0.103	0.108	0.107	0.106
Total	($/dth @ Full Contract)	0.370	0.390	0.386	0.383
Silverado Path					
Reservation Charge	($/dth/mo)	3.814	3.776	3.738	3.701
Usage Charge	($/dth)	0.065	0.063	0.063	0.062
Total	($/dth @ Full Contract)	0.190	0.188	0.186	0.184

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 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.

Table 7
As-Available Backbone Transportation
On-System Transportation Service

		GA III 2007	2008	2009	2010
Redwood Path					
Usage Charge	($/dth)	0.377	0.360	0.356	0.353
Baja Path					
Usage Charge	($/dth)	0.370	0.390	0.386	0.383
Silverado Path					
Usage Charge	($/dth)	0.190	0.188	0.186	0.184
Mission Path					
Usage Charge	($/dth)	0.000	0.000	0.000	0.000

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 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.

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Table 8
Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries

		GA III 2007	2008	2009	2010
SFV Rate Design					
Redwood, Silverado and Mission Paths Off-System					
Reservation Charge	($/dth/mo)	9.323	8.910	8.820	8.733
Usage Charge	($/dth)	0.008	0.007	0.007	0.007
Total	($/dth @ Full Contract)	0.314	0.300	0.297	0.294
Baja Path Off-System					
Reservation Charge	($/dth/mo)	8.905	9.419	9.325	9.232
Usage Charge	($/dth)	0.015	0.016	0.015	0.015
Total	($/dth @ Full Contract)	0.308	0.325	0.322	0.319
MFV Rate Design					
Redwood, Silverado and Mission Paths Off-System					
Reservation Charge	($/dth/mo)	5.413	5.173	5.120	5.070
Usage Charge	($/dth)	0.136	0.130	0.129	0.127
Total	($/dth @ Full Contract)	0.314	0.300	0.297	0.294
Baja Path Off-System					
Reservation Charge	($/dth/mo)	6.756	7.145	7.075	7.004
Usage Charge	($/dth)	0.086	0.090	0.089	0.089
Total	($/dth @ Full Contract)	0.308	0.325	0.322	0.319
As-Available Service					
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System					
Usage Charge	($/dth)	0.377	0.360	0.356	0.353
Mission Paths (From on-system storage) Off-System					
Usage Charge	($/dth)	0.000	0.000	0.000	0.000
Baja Path Off-System					
Usage Charge	($/dth)	0.370	0.390	0.386	0.383

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 76.5 percent load factor.

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

e) Dollar difference are due to rounding.

Table 9
Firm Backbone Transportation
Expansion Shippers – Annual Rates (G-XF)
SFV Rate Design

		GA III 2007	2008	2009	2010
SFV Rate Design					
Reservation Charge	($/dth/mo)	6.820	6.514	6.434	6.318
Usage Charge	($/dth)	0.001	0.002	0.002	0.002
Total	($/dth @ Full Contract)	0.225	0.216	0.213	0.210

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They 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.

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Table 10
Storage Services

		GA III 2007	2008	2009	2010
Core Firm Storage (G-CFS)					
Reservation Charge	($/dth/mo)	0.109	0.109	0.109	0.109
Standard Firm Storage (G-SFS)					
Reservation Charge	($/dth/mo)	0.135	0.135	0.135	0.135
Negotiated Firm Storage (G-NFS)					
Injection	($/dth/d)	15.634	15.634	15.634	15.634
Inventory	($/dth/mo)	1.621	1.621	1.621	1.621
Withdrawal	($/dth/d)	11.787	11.787	11.787	11.787
Negotiated As-Available Storage (G-NAS) - Maximum Rate					
Injection	($/dth/d)	15.634	15.634	15.634	15.634
Withdrawal	($/dth/d)	11.787	11.787	11.787	11.787
Market Center Services (Parking and Lending Services)					
Maximum Daily Charge ($/Dth/day)		0.970	0.970	0.970	0.970
Minimum Rate (per transaction)		$ 57.00	$ 57.00	$ 57.00	$ 57.00

Notes:

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

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

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

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

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

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

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

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

i) Dollar difference are due to rounding.

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Table 11
Local Transmission Rates
($/dth)

	GA III 2007	2008	2009	2010
Base Rates				
Core Retail	0.311	0.323	0.330	0.337
Noncore Retail and Wholesale	0.134	0.140	0.143	0.146
Rate Adders				
Core				
Line 138 (16 miles of 30"pipe)		0.000	0.013	0.017
Line 108 (11 miles of 24" pipe)		0.000	0.014	0.015
Line 406 (15 miles of 30" pipe)		0.000	0.000	0.012
Line 407 (4 miles of 30" pipe)		0.000	0.000	0.003
Line 407 (8 miles of 30" pipe)		0.000	0.000	0.007
Total		0.000	0.027	0.054
Noncore Retail & Wholesale				
Line 138 (16 miles of 30"pipe)		0.000	0.006	0.008
Line 108 (11 miles of 24" pipe)		0.000	0.006	0.007
Line 406 (15 miles of 30" pipe)		0.000	0.000	0.005
Line 407 (4 miles of 30" pipe)		0.000	0.000	0.001
Line 407 (8 miles of 30" pipe)		0.000	0.000	0.003
Total		0.000	0.012	0.023
Total -- Base plus Adders				
Core Retail	0.311	0.323	0.357	0.391
Noncore Retail and Wholesale	0.134	0.140	0.154	0.169

Notes:

a) The Gas Accord IV local transmission rates for 2009 and 2010 include a base rate component plus a rate adder for specific local transmission capital projects, as designated in Section 8.4 of the Gas Accord IV Settlement Agreement.

Table 12
Customer Access Charges

		GA III 2007	2008	2009	2010
G-EG / G-NT ($/month)					
Transmission and Distribution					
	(Therms/Month)				
Tier 1	0 to 5,000	$61.85	$61.85	$61.85	$61.85
Tier 2	5,001 to 10,000	$184.23	$184.23	$184.23	$184.23
Tier 3	10,001 to 50,000	$342.89	$342.89	$342.89	$342.89
Tier 4	50,001 to 200,000	$450.01	$450.01	$450.01	$450.01
Tier 5	200,001 to 1,000,000	$652.92	$652.92	$652.92	$652.92
Tier 6	1,000,001 and above	$5,538.45	$5,538.45	$5,538.45	$5,538.45
Wholesale ($/month)					
Alpine		$333.28	$333.28	$333.28	$333.28
Coalinga		$1,474.03	$1,474.03	$1,474.03	$1,474.03
Island Energy		$998.71	$998.71	$998.71	$998.71
Palo Alto		$4,914.73	$4,914.73	$4,914.73	$4,914.73
West Coast Gas - Castle		$856.26	$856.26	$856.26	$856.26
West Coast Gas - Mather		$782.50	$782.50	$782.50	$782.50

Notes:

a) The rate design for the customer access charge may be addressed in PG&E's Biennial Cost Allocation Proceedings (BCAP). Any changes to the CAC rate design will be based on the 2008-2010 Gas Accord IV CAC revenue requirement

Table 13
Self Balancing Credit
($/dth)

	GA III 2007	2008	2009	2010
Self Balancing Credit	($0.011)	($0.011)	($0.011)	($0.011)

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.