BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Update Pipeline Safety Enhancement Plan (U 39 G)	Application No. ___________

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 G) PIPELINE SAFETY ENHANCEMENT PLAN UPDATE APPLICATION

LISE H. JORDAN
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: LHJ2@pge.com
KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") files this Pipeline Safety Enhancement Plan ("PSEP" or "Implementation Plan") Update Application, pursuant to Ordering Paragraph ("OP") 11 of Decision ("D.") 12-12-030, and Article 2 of the Commission's Rules of Practice and Procedure. PG&E's August 26, 2011 PSEP was based on gas transmission pipeline data in the Gas Transmission Geographic Information System ("GIS") as of January 2011. In 2011, PG&E embarked on a massive effort to collect and organize the necessary pipeline strength test and pipeline features data to validate the Maximum Allowable Operating Pressure ("MAOP") of PG&E's gas transmission pipelines. During that effort, PG&E developed an inventory of all pipe sections, components, and each of the associated characteristics, in a Pipeline Features List ("PFL"). This PSEP Update Application presents the results of re-running these updated, validated data through the Decision Tree approved in D.12-12-030, to more closely align the scope of work to be performed under PSEP to updated pipeline features data.

As a result of records located of prior strength tests on many of PG&E's gas transmission pipelines, and other information regarding pipeline features learned during MAOP validation, PG&E proposes in this PSEP Update Application to reduce the 2011-2014 strength testing program from 783 miles to 658 miles, and to reduce the pipe replacement program for the same period from 185.7 miles to 143.3 miles. This net reduction in scope is due to records found (which decreased pipeline mileage that needs to be addressed) and other information learned about the attributes of our pipelines during MAOP validation (which in some cases allowed PG&E to defer work that was previously planned, and in other cases accelerated work that had been previously planned for after 2014). The net reduction does not compromise safety.

This reduction in scope results in a decrease of capital costs for PSEP of $237.6 million, and a reduction in PSEP Operating and Maintenance ("O&M") expenses of $31.2 million, for an overall reduction of revenue requirements to be collected from customers of approximately $52.7 million for the 2012-2014 period. The revised costs set forth above are based on the same unit cost calculators approved in D. 12-12-030, despite the fact that actual costs are running significantly above the approved unit costs embedded in the cost calculators.[1/] This revenue requirement reduction results in a PSEP rate reduction for all customer classes. A typical residential customer using 37 therms per month would see an average monthly gas bill decrease of $0.06 in 2013. A typical small business customer using 287 therms per month would see an average monthly gas bill decrease of $0.44 in 2013.

Based upon the detailed information presented in PG&E's testimony and work papers supporting this PSEP Update Application, PG&E requests that the Commission approve the revised scope of work based on updated pipeline data, and allow PG&E to collect the PSEP revenue requirement (which is reduced from the revenue requirement approved in D.12-12-030) in customers' rates.

1/ PG&E estimates that, through the end of 2014, shareholders will have absorbed in excess of $1 billion on pipeline strength testing and replacement alone.

II. BACKGROUND

A. PG&E's August 26, 2011 Pipeline Safety Enhancement Plan

Commission Decision 11-06-017 required all California gas transmission operators to file a Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan to pressure test or replace all in-service natural gas transmission pipelines that have not previously been pressure tested. Decision 11-06-017 also indicated that priority should be given to addressing pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 High Consequence Areas ("HCA").[2/]

PG&E filed its Implementation Plan on August 26, 2011, proposing a scope of work, revenue requirements and rates for the 2011-2014 period. Two aspects of PG&E's August 26, 2011 PSEP—the Pipeline Modernization Program and the MAOP Validation Project—are relevant to this Update Application and are described further below.

1. Pipeline Modernization Program

Through the Pipeline Modernization Program, PG&E proposed to: (1) pressure test or replace all in-service natural gas transmission pipelines in California that do not have verifiable records of a pressure test; (2) set forth criteria on which pipeline segments are identified for replacement instead of pressure testing; (3) provide a priority-ranked schedule for pressure testing and replacement of pipe not previously pressure tested; and (4) set forth criteria for use in deciding to retrofit pipelines to allow for In-Line Inspection ("ILI") tools.

PG&E developed a Pipeline Modernization Decision Tree that was designed to assess for threats at the pipe segment level. As a key part of the August 2011 Implementation Plan, every gas transmission pipe segment was analyzed with the Decision Tree to determine a

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2/ D.11-06-017, *mimeo*, p. 20.

recommended action—such as strength test, replacement of pipe, or ILI—to establish a known margin of safety. Each action is denoted by an "Action Box."

Based on the Decision Trees, PG&E proposed to strength test about 783 miles of pipe segments before December 31, 2014, focusing on the following types of pipe:

- Pipe manufactured by processes known to produce less robust weld seams by current standards, or weld seams with poor fracture toughness. These include pre-1970, low-frequency electric resistant weld ("ERW"), flash welded, single submerged arc weld ("SSAW"), furnace butt welded, and lap welded pipe operating between 20% and 30% Specified Minimum Yield Strength ("SMYS") in urban areas.
- All urban-area pipes[3/] operating at or above 30% SMYS, without an adequate strength test, unless scheduled for replacement.

In addition, PG&E planned to replace about 186 miles of pipeline during the 2011-2014 period, focusing on the following types of pipe:

- Pipe manufactured by processes generally thought to produce less robust weld seams by current standards, or weld seams with poor fracture toughness, including pre-1970, low-frequency ERW, flash welded, SSAW, furnace butt welded, lap welded, and hammer welded pipe operating at or above 30% SMYS in urban areas.
- Pipelines constructed with welding techniques generally thought to produce low toughness or girth welds such as oxygen-acetylene welds, bell-to-bell chill ring

3/ PG&E defined urban pipes as pipeline segments located within Class 2, 3 and 4 and Class 1 HCAs.

welds, bell and spigot welds, and pre-1940 arc welds operating at or above 30% SMYS in urban areas.

Finally, PG&E proposed to retrofit all pipelines operating above 30% SMYS, and many below 30% SMYS, to accommodate inspections using current intelligent "pigging" technologies. PG&E included 199 miles of pipeline retrofit for ILI and 234 miles of actual in-line inspections (or "ILI runs") before December 31, 2014.

2. MAOP Validation Project

In 2011, PG&E launched a massive effort to collect and organize all pipeline strength tests and pipeline features data necessary to re-calculate the MAOP of gas transmission pipelines and all associated components. The original source documentation, which includes the characteristics and specifications of each pressure-containing component of the pipeline, was used to support the MAOP calculation for each component, and the resulting MAOP for each pipeline. The inventory included electronic links to source information about each pipeline and each component in order to enhance transparency to the source used to derive critical data.

Given the scale of this effort, the MAOP Validation Project was separated into three parts, with interim deliverables defined along the way. The first part of the MAOP Validation Project involved a comprehensive search of records to locate and scan all strength test records in an interim electronic database for all Class 3 and 4 pipeline segments, and all HCA segments in Class 1 and 2. Part 2 of the MAOP Validation Project focused on validating the MAOP for Class 3 and 4 pipeline segments and all HCA pipelines in Class 1 and 2. Part 3 consisted of MAOP validation of all remaining gas transmission pipelines in PG&E's system.

B. Decision 12-12-030

1. Approval of Pipeline Program and MAOP Validation Project

The Commission issued D. 12-12-030 on December 28, 2012, approving PG&E's Pipeline Modernization Decision Tree and Pipeline Modernization scope of work.[4/] The Commission adopted program-based upper limits on expense and capital costs to be recovered from customers through 2014.[5/] To the extent specific authorized projects are not completed by the end of 2014 and not replaced with other higher priority projects, D.12-12-030 requires that the cost limits be reduced by the amounts associated with the project not completed.[6/] In addition, the Commission found that PG&E's shareholders should absorb the costs of pressure testing pipelines placed into service after January 1, 1956 for which PG&E lacks pressure test records.[7/]

2. Requirement to File a PSEP Update Application

The Commission ordered PG&E to file an application after the completion of its MAOP Validation Project and records search to present the results of those efforts, and update its authorized revenue requirements and related budgets, consistent with D.12-12-030.[8/] The Commission specifically directed PG&E to submit an updated pipe segment database with the PSEP Update Application.[9/] The Commission subsequently approved PG&E's request for an extension of time to file the PSEP Update Application, to October 29, 2013.

The decision also states that the "specific showing that PG&E will be required to provide

4/ D.12-12-030, Conclusion of Law ("COL") 9.

5/ *Id.*, COL 37.

6/ *Id.*, COL 37; p. 108.

7/ *Id.*, COL 15, 16.

8/ *Id.*, OP 11.

9/ *Id.*, pp. 4, 115.

in its application will be considered in a workshop to be held no later than 90 days from the effective date of this decision."[10/] That workshop was held at the Commission on March 26, 2013. PG&E and the parties did not reach agreement at the workshop regarding the filing requirements for the Update Application. Since the workshop, PG&E has continued discussions with the Office of Ratepayer Advocates ("ORA"[11/]), The Utility Reform Network ("TURN"), the Safety and Enforcement Division ("SED"), and the Energy Division ("ED"). ORA and TURN filed a motion on August 22, 2013, seeking a ruling limiting the scope of this PSEP Update Application. In PG&E's response to the motion, PG&E described its intended scope of the PSEP Update Application. This PSEP Update Application is consistent with the scope as described in PG&E's September 6, 2013 response to ORA's and TURN's motion. There has been no ruling on the motion.

III. PG&E'S PSEP UPDATE APPLICATION

This section describes PG&E's PSEP Update Application, which consists of five chapters of testimony, an updated PSEP pipe segment database, and several volumes of workpapers.

A. The Scope Of The PSEP Update Application Is Consistent With D.12-12-030

Decision 12-12-030 adopted PG&E's Pipeline Modernization Decision Tree, but recognized that the PSEP is "subject to revision and updating as new information comes to light."[12/] In particular, the Commission found that "new safety engineering information may provide the analytical foundation for revising priorities."[13/] Accordingly, "improvements, efficiencies, and adjustments to the Implementation Plan based on sound engineering data and

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10/ *Id.*, p. 115.

11/ ORA was formerly known as the Division of Ratepayer Advocates.

12/ D.12-12-030, *mimeo*, p. 84.

13/ *Id.*

that further the objectives of the Plan are within the scope of the Plan."[14/] Furthermore, the Commission found that PG&E justified including within the scope of work to be completed during 2012-2014 pipeline segments located in Class 1 or 2 non HCA locations, but adjacent to Class 3 or 4 locations, or where including those segments was supported by an economic or engineering rationale.[15/]

This PSEP Update Application is consistent with the Commission's recognition that the scope of the projects would change as a result of new information learned from records validation. In particular, as PG&E explains further in the accompanying testimony, our 2011 PSEP filing was based on a "snapshot" of the GIS data taken in January 2011, before PG&E completed its records search and MAOP validation work, and before PG&E completed the system-wide class location studies in 2011 and 2012.

MAOP Validation was much broader than simply locating records of prior strength tests; it was an undertaking to collect and organize all pipeline strength tests and pipeline features data necessary to re-calculate the MAOP of gas transmission pipelines and all associated components. PG&E based the PSEP work reflected in the Update Application on what we know about our gas transmission pipeline segments and components today.[16/] PG&E processed the updated data through the Pipeline Modernization Decision Tree, and has spent months preparing a transparent PSEP Update Application that shows *every* change from PG&E's August 2011 PSEP Application, at the pipe segment level.[17/]

14/ *Id.*; see also Finding of Fact 32.

15/ *Id.*, COL 20; pp. 66-67.

16/ This includes updated information on Class Location and HCAs based on work performed in 2011 and 2012.

17/ The August 2011 PSEP was also based on a database that identified the decision tree action for each pipeline segment in the PG&E gas transmission system.

In addition, PG&E is using the same unit cost calculators to calculate project costs for the PSEP Update Application that were approved in D.12-12-030, despite the fact that actual costs are running significantly above the approved unit costs embedded in the cost calculators. While an individual PSEP project may be shorter or longer than originally filed following data validation, the unit cost calculations remained the same. Applying the same unit cost calculators from the original PSEP filing to project scopes that have been updated as a result of records validation isolates the changes due to records validation, and avoids relitigating unit costs.

B. PSEP Database Validation

The 2011-2014 PSEP scope delineated in PG&E's August 2011 PSEP filing was based on information from PG&E's gas transmission GIS as of January 2011 and updated pipeline information from the MAOP Records Validation Project as of April 30, 2011. The GIS is a two-dimensional mapping tool that places an asset, such as a pipeline segment or valve, onto an electronic map with Global Positioning System coordinates for geographic referencing. PG&E's GIS contains records on approximately 6,750 miles of transmission gas pipeline, subdivided into over 36,600 individual pipe segments based on changes in physical attributes, characteristics and environment. Throughout this proceeding, PG&E stated it used a January 2011 "snapshot" of the GIS database, taken before PG&E completed records search work and MAOP validation. In particular, pipeline attribute information and pressure test data had not been verified. However, the GIS database was the best, and most readily available, electronic information source PG&E had at the time of the PSEP filing. In addition, projects included in PG&E's August 26, 2011 PSEP did not reflect updated pipeline segment class location data from the Class Location study that was performed in 2011 and 2012.

The MAOP Validation team has developed a PFL for every numbered pipeline route. The PFL contains a list of every pipeline component, and specific attribute information on each component such as type, size, diameter, wall-thickness, grade of steel, pressure test information, and date of install. This is the MAOP validated pipeline source data that PG&E used to verify and validate PSEP segment level detail and ensure that the appropriate mitigation is performed for each pipeline segment.[18/]

C. Changes To PSEP Project Scope Based On New Decision Tree Results

In order to prepare the PSEP Update Application, the validated pipe segment data was processed through the Decision Tree to verify the PSEP recommended actions. As a result of re-running validated data through the Decision Tree, some projects previously identified no longer need to be done, some future projects were re-prioritized as high priority work given information learned about pipeline attributes, and some projects had scopes refined based upon information learned during records validation. The records search and MAOP Validation scope of work went well beyond validating pipeline pressure test records. While the presence of a valid pressure test record is certainly important, the MAOP records validation process was far more inclusive in the volume and level of pipeline component detail and information PG&E assembled on our entire gas transmission system. This component level detail is critical in order to verify key pipeline attribute information used in the Decision Tree, and to ensure that the pipeline component/segment is correctly processed through the Decision Tree, and the appropriate work is performed to address the threats on that pipeline segment. This process is described in further detail in Chapter 2 of accompanying testimony, "Gas Transmission Pipeline Modernization Program Update."

Following data validation and processing the new pipeline segment data through the Decision Tree, one of five actions are recommended for each pipeline segment and proposed

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18/ It is important to recognize, however, that our older, historic records are not complete, and that records validation is an ongoing effort subject to continuous improvement. We will continue to discover new information about our pipelines through records validation and field testing of engineering assumptions.

project. Each action is described below.

1. No Change to PSEP Phase 1 Action

Under this scenario, MAOP records and data validation confirmed the pipeline segment attributes and pressure testing data identified in the PSEP database were accurate as filed in August 2011, and there were no changes to the class location or HCA; therefore, no changes to the action proposed in August 2011 are warranted.

2. Changes Due to Records Found of Prior Strength Test

If MAOP records and data validation confirmed a proposed PSEP Phase 1 pressure test or replacement project had a valid pressure test record that complied with the regulations or industry standards at the time the test was performed, the project was removed from the PSEP scope.

3. Changes Due to MAOP Validation, Class Location and HCA Updates

If MAOP records and data validation confirmed that the pipeline attributes for an identified PSEP Phase 1 pipeline segment were different than what was known when the August 2011 PSEP was submitted, the result of re-running the validated data through the Decision Tree could cause a change in the Decision Tree recommended action. Updates to pipeline attributes (such as age of installation, type of long-seam, and pipe joining practices, among others) could cause a change in the Decision Tree recommended action for a pipe segment.[19/]

This action resulted in multiple possible outcomes:

(1) No change in recommended Phase 1 actions;

(2) A project could change from test to replace or replace to test;

(3) A project could be deferred beyond 2014 or cancelled consistent with D.12-12-

19/ In addition, the PSEP database has been updated to reflect Class Location or HCA changes. Pipeline segments with updated Class Location (whether upward or downward) and all HCA changes were processed through the Decision Tree for possible changes in recommended actions.

030[20] (if, for example, a segment changes from a Class 2 HCA to a Class 2 non-HCA); or

(4) Pipeline segments not prioritized for a PSEP Phase 1 action as of the August 2011 PSEP filing (based on information in GIS at the time) may now require a Phase 1 replacement or pressure test based on validated pipeline attributes. Pipeline segments not identified in the August 2011 PSEP filing—based on information within GIS as of January 2011—might require a replacement or pressure test based upon new pipeline attribute data learned as a result of MAOP validation (if, for example, a segment was found to have a particular weld type for which the Decision Tree indicates some type of mitigation).

4. Changes Due To Engineering Judgment/External Factors

After the data validation process and Decision Tree outcome were completed, PG&E compared the original PSEP project scope to the updated pipeline segment Decision Tree results. As the Commission recognized in D.12-12-030, there are circumstances in which PG&E's proposed action for a particular pipe segment differs from the raw Decision Tree results for that segment.[21] PG&E has identified 20 unique reasons why the actions proposed for a pipeline segment may deviate from the Decision Tree results. These are referred to as "Deviations Due To Engineering Judgment." The Deviations Due To Engineering Judgment are intended to capture operational and/or economic efficiencies that can be gained by deviating from the raw Decision Tree results. The Deviations Due To Engineering Judgment are based on sound engineering principles, and do not compromise safety.[22] Table 2-1 in Chapter 2 lists each possible deviation, along with a description and justification for the deviation. Deviations Due

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20/ The Commission concluded that pipeline segments in Class 1 or 2 locations may be deferred beyond Phase 1. D.12-12-030, *mimeo*, pp. 66-67.

21/ D.12-12-030, *mimeo*, p. 84; see also Finding of Fact 32.

22/ In most cases, the deviations result in taking a more conservative approach to mitigation for particular segments.

To Engineering Judgment at the pipeline segment level are also noted in the PSEP database and workpapers that accompany this filing. Nine of the 20 deviations were identified and used in PG&E's August 2011 PSEP filing. Eleven additional deviations were added in response to D.12-12-030, or following detailed engineering analysis.

5. Changes Due to Retirements and Downrates

The last type of change, which was not considered or addressed in the August 2011 PSEP filing, is an opportunity to reduce PSEP program scope, based on engineering principles and without compromising safety. PG&E has identified opportunities to either convert a gas transmission pipeline to a gas distribution pipeline, or retire the gas transmission pipeline because it is no longer needed to serve customers.[23/] There are 10 PSEP Phase 1 projects that meet these criteria and they are identified within the updated PSEP database accompanying the supporting testimony for this Application and in the workpapers. PG&E has included the estimated cost (or actual cost if available) to retire these lines versus the cost to replace, whichever option is lower. PG&E does not request recovery in this Application for the cost to downrate gas transmission pipeline segments to distribution pressures.

D. Updated Program Scope and Associated Costs

1. Calculating Cost Responsibility

Decision 12-12-030, Attachment E, provides authorized capital expenditure and expense program costs that are recoverable through rates for 2012-2014, by applying criteria in the decision, using the pipeline attribute and strength test data contained in the original PSEP database. As explained further in Chapter 2, PG&E developed updated PSEP project costs by applying the cost recovery criteria delineated in D.12-12-030 to the validated pipeline data and

23/ Retirements and downrates are also identified as Deviations Due To Engineering Judgment.

updated PSEP projects. If a PSEP project was determined to have a traceable, verifiable and complete record of a prior strength test, the PSEP project was removed from the program scope and the overall program capital expenditure or expense costs were reduced by the requested amount. Similarly, in accordance with D.12-12-030, COL 20, PG&E generally removed projects that contained only Class 2 and Class 1 non-HCA pipe from PSEP scope through 2014.[24/] The scope and length of pipeline replacement projects that had significant lengths of Class 2 non-HCA pipe were also minimized.

If a project remains in the PSEP Update Application (because, for example, no record of a prior strength test was found), then the PSEP project was validated, the scope and length of the project was defined, and the PSEP database was updated. Subsequently, the cost of the project was recalculated to determine gross project costs. When calculating gross project costs, PG&E used the same approved unit cost calculator used for the August 2011 PSEP filing and adopted in D.12-12-030.[25/]

After the gross costs of the updated PSEP projects were calculated, PG&E calculated any disallowances, in accordance with D.12-12-030. Disallowance cost for pipeline replacement projects is defined as the cost to strength test any post-1955 pipeline without a validated strength test record using the cost allowance calculation proposed by ORA and adopted in 12-12-030.[26/] Similarly, for strength testing, PG&E performed a *pro rata* reduction of the cost for any post-1955 pipe segments that lacked a record of a prior strength test that met the requirements at the

24/ In some instances, because engineering and permitting were far along, and commitments had been made to communities and permitting agencies, PG&E executed and completed these projects.

25/ D.12-12-030, COL 17, 21.

26/ *Id.*, p. 115.

time of the test. Examples of how PG&E performed the calculation for cost disallowances are provided in Chapter 2.

2. Updated Program Scope and Associated Costs for Pipe Replacement

In PG&E's August 26, 2011 PSEP filing, PG&E identified 169 individual pipeline replacement projects that totaled 185.7 miles of pipeline segment replacement. D.12-12-030, Attachment E showed authorized capital expenditures for Pipeline Modernization of $852.5 million. In this PSEP Update Application, PG&E proposes 143.3 miles of PSEP pipeline replacement. This represents a 42.4 mile (23%) decrease from the August 26, 2011 PSEP filing. The table below provides a high level summary of how the original 185.7 segment miles of pipeline replacement have changed.

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION PIPELINE MODERNIZATION PROGRAM UPDATE
PSEP PIPELINE REPLACEMENT – VALIDATED SCOPE CHANGES

Line No.	Number of Miles	Reason for Scope Change
1	185.7	Filed segment miles to be replaced
2	(33.0)	Filed segment miles cleared (valid test record)
3	(22.0)	Filed segment miles from replacement to strength test
4	(24.5)	Filed segment miles deferred beyond Phase 1 (Class 1 and 2 non-adjacent)
5	(8.5)	Filed segment miles deferred beyond Phase 1 (Class 3)
6	(2.2)	Filed segment miles addressed outside of PSEP
7	24.9	Segment miles from strength test to replacement
8	22.9	Segment miles not included in August 2011 PSEP filing, but now meet Phase 1 replacement criteria
9	143.3	Total updated segment miles to be replaced in PSEP Phase 1

The workpapers supporting Chapter 2 of PG&E's accompanying testimony provide a detailed list of specific pipeline replacement projects and pipeline segments to be replaced within PSEP.

The table below contains the updated capital expenditures that PG&E proposes be recovered from ratepayers.

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION PIPELINE MODERNIZATION PROGRAM UPDATE
UPDATED CAPITAL EXPENDITURES BY MAT CODE
($ IN MILLIONS)

Line No.	Mat Code	MAT Code Description	2011	2012	2013	2014	Total
1	44A	StanPac Capital (Pipe Only)	–	$0.0	$0.4	–	$0.4
2	2H1	Pipe Replacement	$10.3	120.9	268.3	$132.0	531.5
3	2H2	Emergency Pipe Replacement	13.9	13.2	13.1	13.0	53.2
4	2H4	Implementation Plan ILI Pipeline Retrofit	1.1	14.4	14.1	–	29.7
5		Total	$25.3	$148.6	$296.0	$145.0	$614.9

Note: Differences due to rounding.

The updated Pipeline Modernization Program capital forecast of $614.9 million represents a $237.6 million reduction from the authorized capital expenditures in D.12-12-030.

3. Updated Program Scope and Associated Costs for Strength Testing

In the August 26, 2011 PSEP filing, PG&E identified 165 individual pipeline strength test projects, 383 unique strength tests, and 783 total segment miles of pipeline to be strength tested.[27/] Decision 12-12-030 authorized PG&E to recover $149.5 million from 2012-2014 for Pipeline Modernization expenses. In this PSEP Update Application, PG&E proposes 658 segment miles of PSEP strength testing through 2014. This is a 125 mile (16%) decrease from the August 26, 2011 PSEP filing. The table below provides a high level summary of how the original 783 segment miles of pipeline strength testing have changed.

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27/ PG&E's August 26, 2011 Prepared Testimony, Chapter 3, Table 305.

TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION PIPELINE MODERNIZATION PROGRAM UPDATE
PSEP PHASE 1 PIPELINE STRENGTH TESTS – VALIDATED SCOPE CHANGES

Line No.	Number of Miles	Reason for Scope Change
1	783.0	Filed segment miles to be strength tested
2	(162.0)	Filed segment miles cleared (valid test record)
3	(25.0)	Filed segment miles from strength test to replacement
4	(58.5)	Filed segment miles deferred beyond Phase 1 (Class 1 and 2 non-adjacent)
5	(14.0)	Filed segment miles deferred beyond Phase 1 (test record met code, but not PSEP)
6	(13.5)	Filed segment miles deferred beyond Phase 1 (Class 3)
7	(3.0)	Filed segment miles addressed outside of PSEP
8	22.0	Segment miles from replacement to strength test
9	129.0	Segment miles not included in August 2011 PSEP filing, but now meet Phase 1 strength test criteria
10	658.0	Total updated segment miles to be strength tested in PSEP Phase 1

The work papers supporting Chapter 2 of the accompanying testimony provide a detailed list of specific projects and pipeline segments to be strength tested before the end of 2014.

The table below contains the updated expense expenditures that PG&E proposes be recovered from ratepayers.

TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION PIPELINE MODERNIZATION PROGRAM UPDATE
UPDATED EXPENSES BY MAT CODE
($ IN MILLIONS)

Line No.	Mat Code	MAT Code Description	2011	2012	2013	2014	Total
1	34A	StanPac Expense (Pipe Only)	–	–	–	–	–
2	KE1	Pipe Strength Test	–	$2.3	$59.6	$45.1	$107.0
3	KE2	Pipe Replacements < 50’	–	–	–	–	–
4	KE3	In-Line Inspection	–	–	1.7	7.5	9.2
5	KEX	Pipeline Other	–	0.0	1.0	1.0	2.1
6		Total	–	$2.3	$62.3	$53.6	$118.3

Note: Differences due to rounding.

The updated Pipeline Modernization expenses of $118.3 million represent a $31.2 million reduction from the authorized expenses in D.12-12-030.

E. Updated Revenue Requirements and Rates

As shown in Chapter 4 of the accompanying testimony, the changes to PSEP scope and cost responsibility described above lead to the proposed revenue requirements in the table below. For comparison purposes, the revenue requirements authorized in D.12-12-030 are also shown in the table below.

TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
IMPLEMENTATION PLAN AUTHORIZED REVENUE REQUIREMENTS
2012-2014
($ IN THOUSANDS)

Update Application Revenue Requirement	2012	2013	2014	Total
Capital-Only Revenue Requirement	$7,253	$33,911	$76,790	$117,954
Expense-Only Revenue Requirement	79,399	70,631	62,347	212,376
Total	$86,653	$104,541	$139,137	$330,331
Disallowance for Costs Incurred Prior to 12/20/12	$(83,804)			
Updated Revenue Requirement	$2,849	$104,541	$139,137	$246,527

Original – D.12-12-030 Revenue Requirement	2012	2013	2014	Total
Capital-Only Revenue Requirement	$9,191	$41,076	$90,605	$140,872
Expense-Only Revenue Requirement	79,399	74,267	90,353	244,020
Total	$88,590	$115,343	$180,958	$384,892
Disallowance for Costs Incurred Prior to 12/20/12	(85,678)			
Adopted Revenue Requirement	$2,913	$115,343	$180,958	$299,214
Change From Adopted Revenue Requirement	$(64)	$(10,802)	$(41,821)	$(52,687)

Updated proposed PSEP rates for 2013 and 2014, described in more detail in Chapter 5 of the accompanying testimony, are shown in the table below, compared to the rates authorized in D.12-12-030:

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TABLE 6
PACIFIC GAS AND ELECTRIC COMPANY
IMPLEMENTATION PLAN RATE COMPONENTS
($ PER THERM)

Line No.		2013 Decision 12-12-30	2013 Update	2014 Decision 12-12-30	2014 Update
1	Core				
2	PSEP – Local Transmission	$0.02024	$0.02047	$0.02953	$0.02464
3	PSEP – Backbone Transmission	0.00327	0.00162	0.00600	0.00382
4	PSEP – Storage	0.00033	0.00022	0.00113	0.00018
5	Total Implementation Plan Rate	$0.02384	$0.02231	$0.03667	$0.02864
6	Noncore – Local Transmission/Distribution Level				
7	PSEP – Local Transmission	$0.00946	$0.00956	$0.01439	$0.01201
8	PSEP – Backbone Transmission	0.00274	0.00136	0.00492	0.00313
9	PSEP – Storage	0.00014	0.00010	0.00048	0.00008
10	Total Implementation Plan Rate	$0.01234	$0.01102	$0.01979	$0.01521
11	Noncore – Backbone Transmission Level				
12	PSEP – Backbone Transmission	$0.00274	$0.00136	$0.00492	$0.00313
13	PSEP – Storage	0.00014	0.00010	0.00048	0.00008
14	Total Implementation Plan Rate	$0.00288	$0.00145	$0.00540	$0.00320

In addition, PG&E provides, as Appendix 1 to this Application, redlined Tables E-1 through E-4, showing PG&E's proposed changes to the tables included as Attachment E to D.12-12-030.

IV. DESCRIPTION OF ACCOMPANYING TESTIMONY, WORK PAPERS AND PSEP DATABASE

PG&E is serving the following testimony in support of its PSEP Update Application. Witness names are noted following the chapter titles:

Chapter 1, MAOP Validation Project (Joe Medina): Chapter 1 describes the development of the Pipeline Features Lists, and the resulting validation of the MAOP for each of PG&E's gas transmission pipelines, including Quality Control processes.

Chapter 2, Gas Transmission Pipeline Modernization Program Update (Todd Hogenson/Ben Campbell): Chapter 2 describes in detail how the pipeline component data that were developed as part of MAOP Validation were processed through the Decision Tree, and the resulting scope and cost changes for the Pipeline Program, including Quality Control processes.

Chapter 3, Quality Assurance (Sumeet Singh): Chapter 3 describes the Quality Assurance processes implemented by PG&E to govern the activities to prepare the PSEP Update Application.

Chapter 4, Results of Operations (Niel Jones): Chapter 4 presents the expense and capital base revenue requirements resulting from the revised scope of work reflected in this PSEP Update Application, for 2012 through 2014.

Chapter 5, Rates (Ray Blatter): Chapter 5 presents rates resulting from the updated PSEP revenue requirements presented in Chapter 4. Chapter 5 compares the core and noncore PSEP rates adopted in D.12-12-030, to the core and noncore PSEP rates resulting from the PSEP Update Application, and presents illustrative average present and proposed rates.

Workpapers: PG&E is also providing workpapers, including workpapers supporting Chapter 2 that show the following information for each proposed updated pipeline replacement and strength testing project: project summary, project scope, project cost, a comparison of the original filed project with the updated project, and a summary of decision tree results for all segments included within a project. In addition, PG&E is providing excel summary tables for "Capital Expenditures by Maintenance Activity Type," and "Expenses by Maintenance Activity Type."

Updated PSEP Database: In accordance with D.12-12-030, PG&E is providing an updated PSEP database that will show, in addition to the original data fields used to develop the August 2011 PSEP filing, additional data that show the results of records review and MAOP validation.

V. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

Decision 11-06-017, which required PG&E and the other gas utilities in the state to file an Implementation Plan, did not require an application. Therefore, PG&E's August 26, 2011 PSEP was not styled as an Application.[28/] By contrast, the Commission in D.12-12-030 specifically required that the PSEP update be filed as an application.[29/] For this reason, PG&E includes below the items required by Commission Rules of Practice and Procedure 2.1, 2.2, and 3.2.[30/]

A. Statutory Authority

PG&E files this Application pursuant to Sections 451, 454, and 729 of the Public Utilities Code, the Commission's Rules of Practice and Procedure, and D.12-12-030, OP 11.

B. Categorization – Rule 2.1.(c)

PG&E proposes that this Application be categorized as a "ratesetting" proceeding.

C. Need for Hearing – Rule 2.1(c)

PG&E does not believe that hearings are necessary for this PSEP Update Application. However, PG&E anticipates that hearings will be requested. PG&E's proposed schedule is set forth in subsection E, below.

D. Issues to be Considered - Rule 2.1(c)

The principal issues are whether:

1. The Pipeline Modernization scope of work proposed in this PSEP Update Application should be approved.

28/ However, because it proposed a rate increase, PG&E provided notice in customers' bills, in newspapers of general circulation, and to cities and counties.

29/ D.12-12-030, OP 11.

30/ PG&E is not seeking to increase rates through this Application. However, in the interest of transparency, PG&E's Application meets the requirements of Commission Rule of Practice and Procedure 3.2.

2. The proposed decreases to the capital and expense costs of the PSEP through December 31, 2014 are just and reasonable and should be approved.

3. The proposed PSEP revenue requirements and rates are just and reasonable and should be approved.

E. Proposed Schedule – Rule 2.1(c)

PG&E's proposed schedule is as follows:

PG&E files PSEP Update Application and serves testimony and workpapers	October 29, 2013
Notice of Filing in Daily Calendar	November 1, 2013
Informal Intervenor Workshop	November 15, 2013
Protests and Reponses to PG&E's PSEP Update Application	December 2, 2013
Reply to Protests	December 12, 2013
Prehearing Conference	December 19, 2013
Scoping Memo Issues	January 3, 2014
Intervenors' Opening Testimony	January 31, 2014
Concurrent Rebuttal Testimony	February 28, 2014
Evidentiary Hearings (if needed)	March 17-19, 2014
Opening Brief	April 16, 2014
Reply Brief	April 30, 2014
Proposed Decision	June 30, 2014
Comments on Proposed Decision	July 21, 2014
Reply Comments on Proposed Decision	July 28, 2014
Final Decision	August, 2014

PG&E is committed to doing what it can to expedite this proceeding. To that end, PG&E

has included in the above schedule an informal workshop that will be open to all parties, prior to the date that parties' protests are due. At this workshop, PG&E will provide parties with a roadmap of the filing, summarize the contents of testimony and workpapers, and answer questions. In addition, PG&E plans to discuss the proposed schedule with the other parties at the November 15, 2013 workshop, in advance of the pre-hearing conference.

F. Legal Name and Principal Place of Business – Rule 2.1(a)

The legal name of the Applicant is Pacific Gas and Electric Company. PG&E's principal place of business is San Francisco, California. Its post office address is Post Office Box 7442, San Francisco, California 94120.

G. Correspondence and Communication Regarding This Application – Rule 2.1.(b)

All correspondence and communications regarding this Application should be addressed to Kerry C. Klein, Lise H. Jordan and Melissa N. Brandt at the addresses listed below:

Kerry C. Klein
Law Department
Pacific Gas and Electric Company
Post Office Box 7442
San Francisco, California 94120
Telephone: (415) 973-3251
Fax: (415) 973-5520
E-mail: KCK5@pge.com

Lise H. Jordan
Law Department
Pacific Gas and Electric Company
Post Office Box 7442
San Francisco, California 94120
Telephone: (415) 973-6965
Fax: (415) 973-5520
E-mail: LHJ2@pge.com

Melissa N. Brandt
Principal Case Manager
Pacific Gas and Electric Company
77 Beale Street, B10A

Overnight hardcopy delivery:

Kerry C. Klein
Law Department
Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, California 94105

Lise H. Jordan
Law Department
Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, California 94105

San Francisco, California 94105
Telephone: (415) 973- 0631
Fax: (415) 973- 9176
E-mail: melissa.brandt@pge.com

H. Articles of Incorporation – Rule 2.2

PG&E is, and since October 10, 1905, has been, an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Restated Articles of Incorporation, effective April 12, 2004, is on record before the Commission in connection with PG&E's Application 04-05-005, filed with the Commission on May 3, 2004. These articles are incorporated herein by reference pursuant to Commission Rule of Practice and Procedure 2.2.

I. Balance Sheet and Income Statement – Rule 3.2(a)(1)

PG&E's most recent balance sheet and income statement were filed with the Commission on September 30, 2013 in A.13-09-015, and are incorporated herein by reference.

J. Statement of Presently Effective Rates – Rule 3.2(a)(2)

The presently effective rates PG&E proposes to modify are set forth in Exhibit A of this Application.

K. Statement of Proposed Changes and Results of Operations at Proposed Rates - Rule 3.2(a)(3)

The proposed changes and the Results of Operations at Proposed Rates are set forth in Exhibits B and C of this Application.

L. General Description of PG&E's Gas Department Plant - Rule 3.2(a)(4)

A general description of PG&E's Gas Department properties, their original cost, and the depreciation reserve applicable to these properties was filed with the Commission on November 15, 2012, in A.12-11-009 and is incorporated herein by reference.

M. Summary of Earnings - Rules 3.2(a)(5) and 3.2(a)(6)

PG&E's 2012 summary of earnings for PG&E's Gas Department, PG&E's Electric Department, and all operating departments was filed with the Commission on September 30, 2013, in A. 13-09-015, and is incorporated herein by reference.

N. Statement of Election of Method of Computing Depreciation Deduction for Federal Income Tax - Rule 3.2(a)(7)

A statement of the method of computing the depreciation deduction for federal income tax purposes was filed with the Commission on November 15, 2012 in A.12-11-009 and is incorporated herein by reference.

O. Most Recent Proxy Statement - Rule 3.2(a)(8)

PG&E's most recent proxy statement dated April 2, 2012 was filed with the Commission in A.12-04-018 on April 20, 2012. This proxy statement is incorporated herein by reference.

P. Type of Rate Change Requested - Rule 3.2(a)(10)

This proposed change reflects changes in PG&E's base revenues to reflect the costs PG&E incurs to own, operate and maintain its gas plant and to enable PG&E to provide service to its customers.

Q. Notice and Service of Application - Rule 3.2(b)-(d)

Within twenty (20) days after filing this Application, PG&E will mail a notice stating in general terms the proposed revenues and rate changes requested in this Application to the parties listed in Exhibit D, including the State of California and cities and counties served by PG&E. The PSEP Update Application is also being served on the parties of record in R.11-02-019 in accordance with Rule 1.9(d).

PG&E will publish in newspapers of general circulation in each county in its service territory a notice of filing this Application. PG&E will also include notices with the regular bills mailed to all customers affected by the proposed changes.

R. Exhibit List and Statement of Readiness

PG&E is ready to proceed with this case based on the testimony of witnesses regarding the facts and data contained in the accompanying exhibits in support of the revenue request set forth in this Application. A list of the exhibits to this Application precedes the exhibits, and a detailed description of the prepared Testimony accompanying this Application is contained in the Table of Contents to the separate volume of prepared Testimony supporting this Application.

VI. REQUEST FOR COMMISSION ORDERS

PG&E requests that the Commission issue appropriate orders:

1. Approving the Pipeline Modernization scope of work proposed in this PSEP Update Application;

2. Approving the proposed decrease to the capital and expense costs of the PSEP through December 31, 2014;

3. Authorizing PG&E to recover a total PSEP revenue requirement of $246,527,000 for 2012-2014 through the Implementation Plan surcharge approved in D.12-12-030;

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4. Establishing a schedule in accordance with PG&E's proposed schedule; and

5. Granting PG&E such other relief as the Commission finds to be just and reasonable.

Respectfully submitted,

By: *\/s\/ Kerry C. Klein*
KERRY C. KLEIN

LISE H. JORDAN
KERRY C. KLEIN
Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: LHJ2@pge.com
KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 29, 2013

VERIFICATION

I, the undersigned, state:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, and am authorized to make this verification for and on behalf of said corporation, and I make this verification for that reason. I have read the foregoing pleading and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed at San Ramon, California, on October 24, 2013.

/s/ Kirk Johnson
KIRK JOHNSON
VICE PRESIDENT
PACIFIC GAS AND ELECTRIC COMPANY

TABLE E-1
Pacific Gas and Electric Company
Implementation Plan Update Revenue Requirements
2011-2014
($ in thousands)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	Capital-Only Revenue Requirement	-	~~$9,191~~ $7,253	~~$41,076~~ $33,911	~~$90,605~~ $76,790	~~$140,872~~ $117,954
2	Expense-Only Revenue Requirement		$79,399	~~$74,267~~ $70,631	~~$90,353~~ $62,347	~~$244,020~~ $212,376
3	Total	-	~~$88,590~~ $86,653	~~$115,343~~ $104,541	~~$180,958~~ $139,137	~~$384,892~~ $330,331
4	Disallowance of months in 2012		~~-$85,678~~ -$83,804			
5	Decision Increase in Revenue Req.		~~$2,913~~ $2,849	~~$115,343~~ $104,541	~~$180,958~~ $139,137	~~$299,214~~ $246,527

Note (1) - Disallowance based on effective date of decision

TABLE E-2 Program Expenses
PACIFIC GAS AND ELECTRIC COMPANY
Update EXPENSES (w/escalation adjustment)
($ IN MILLIONS)

Line No.	Description	2011(a)	2012(b)	2013	2014	Total
1	Pipeline Modernization Program	0.0	2.3	~~65.9~~ 62.3	~~81.3~~ 53.6	~~149.5~~ 118.3
2	Valve Automation Program	0.0	0.1	3.0	3.6	6.7
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	1.1	1.0	2.1
5	Program Management Office	0.0	0.1	3.3	3.2	6.6
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Expenses	$0.0	$2.6	~~$73.3~~ $69.7	~~$89.2~~ $61.5	~~$165.0~~ $133.7

Note: Differences due to rounding.
(a) The 2011 expenses will be funded by shareholders.
(b) The 2012 expenses will be funded by shareholders until effective date of decision.

TABLE E-3
PACIFIC GAS and ELECTRIC COMPANY
Update Capital Expenditures (w/escalation adjustment)
($ IN MILLIONS)

Line No.	Description	2011	2012	2013	2014	Total
1	Pipeline Modernization Program	~~30.5~~ 25.3	~~214.9~~ 148.6	~~290.1~~ 296.0	~~317.0~~ 145.0	~~852.5~~ 614.9
2	Valve Automation Program	13.7	38.9	51.6	24.8	129
3	Pipeline Records Integration Program	0	0	0	0	0
4	Interim Safety Enhancement Measures	0	0	0	0	0
5	Program Management Office	3	6.5	6.5	6.3	22.3
6	Contingency	0	0	0	0	0
7	Total Capital Expenditures	~~$47.2~~ $42.0	~~$260.3~~ $194.0	~~$348.2~~ $354.1	~~$348.0~~ $176.0	~~$1003.8~~ $766.2

Note: Differences due to rounding.
Note - Adopted Revenue Requirement includes 2011 and 2012 adjustments associated with authorized capital expenditures

Table E-4 - Update Combined Expense and Capital
w/Escalation Adjustment
($ IN MILLIONS)

Line No.	Description	2011(a)	2012 (b)	2013	2014	Total
1	Pipeline Modernization Program	~~30.5~~ 25.3	~~217.3~~ 151.0	~~356.0~~ 358.3	~~398.2~~ 198.6	~~1002.0~~ 733.2
2	Valve Automation Program	13.7	39.0	54.6	28.4	135.7
3	Pipeline Records Integration Program	0.0	0.0	0.0	0.0	0.0
4	Interim Safety Enhancement Measures	0.0	0.0	1.1	1.0	2.1
5	Program Management Office	3.0	6.6	9.8	9.5	28.9
6	Contingency	0.0	0.0	0.0	0.0	0.0
7	Total Cost	~~$47.2~~ $42.0	~~$262.9~~ $196.6	~~$421.5~~ $423.8	~~$437.2~~ $237.6	~~$1,168.8~~ $899.9

Note: Differences due to rounding.
(a) The 2011 expenses will be funded by shareholders.
(b) The 2012 expenses will be funded by shareholders until effective date of decision.

EXHIBITS

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EXHIBIT A

Statement of Presently Effective Rates

Pacific Gas and Electric Company

Gas RateFinder

October 2013 Volume 42-G, No.10

The *Gas RateFinder* is produced by the Pacific Gas and Electric Company Analysis and Rates Department as a quick reference to most PG&E gas rates, for both PG&E employees and customers. It does not replace tariff sheets.

This *Gas RateFinder* contains core and noncore gas price changes for the month of **October 2013.**

To view the current Gas RateFinder and previous editions, please visit PG&E's Internet site at: http://www.pge.com/tariffs (Select #17)

Questions about PG&E's rates or tariffs can be E-mailed to: Tmail@pge.com, or by phone by calling 1-800-743-5000.

Contents

*[*Rates Change Monthly]*

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I - Core Gas Rates

Residential Gas Rates

The residential gas rates below are effective October 1, 2013, through October 31, 2013.

	SCHEDULES G-1, GM, GS, GT		SCHEDULES GL-1, GML, GSL, GTL	
	BASELINE	EXCESS	BASELINE	EXCESS
Procurement Charge (per therm)	$0.43296	$0.43296	$0.43296	$0.43296
Transportation Charge (per therm)	$0.52817	$0.84507	$0.52817	$0.84507
CSI – Solar Thermal Exemption (per therm)	--	--	-$0.00157	-$0.00157
Care Discount (per therm)	n/a	n/a	-$0.19191	-$0.25529
Total Residential Schedule Charge[1/]	**$0.96113**	**$1.27803**	**$0.76765**	**$1.02117**
Schedule G-PPPS (Public Purpose Program Surcharge)[1/] (per therm)	$0.06551	$0.06551	$0.04370	$0.04370
Minimum Transportation Charge (G-1 Only) [2/] (per day)	$0.09863			
Discount (per day)				
GS & GSL only (per dwelling unit)	$0.20900		$0.20900	
GT & GTL only (per installed space)	$0.48200		$0.48200	

[1/]Schedule G-PPPS needs to be added to the Total Charge for bill calculation. See Schedule G-PPPS.
[2/]The Transportation Charge will be no less than the Minimum Transportation Charge. The Minimum Transportation Charge does not apply to submetered tenants of master-metered customers served under gas Rate Schedules GS and GT.

Baseline Territories and Quantities *(changed April 1, 2012)*

WINTER (November 1 – March 31)					SUMMER (April 1 - October 31)				
TERRITORY	INDIVIDUALLY METERED		MASTER METERED (GM & GML only)		TERRITORY	INDIVIDUALLY METERED		MASTER METERED (GM & GML only)	
	Monthly	Daily	Monthly	Daily		Monthly	Daily	Monthly	Daily
P	66	2.18	32	1.06	P	14	0.46	10	0.33
Q	61	2.02	24	0.79	Q	20	0.65	18	0.59
R	55	1.82	38	1.26	R	13	0.43	11	0.36
S	58	1.92	20	0.66	S	14	0.46	10	0.33
T	54	1.79	34	1.12	T	20	0.65	18	0.59
V	54	1.79	37	1.22	V	21	0.69	17	0.56
W	51	1.69	27	0.89	W	14	0.46	9	0.29
X	61	2.02	24	0.79	X	18	0.59	11	0.36
Y	80	2.64	32	1.06	Y	25	0.82	15	0.49

To calculate bills use daily quantity (monthly provided for information purposes only).

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Residential Natural Gas Vehicle Rates

The residential natural gas vehicle rates below are effective October 1, 2013, through October 31, 2013.

	SCHEDULE G1-NGV	SCHEDULE GL1-NGV
Customer Charge (per day)	$0.41425	$0.33140
Procurement Charge (per therm)	$0.41099	$0.41099
Transportation Charge (per therm)	$0.29678	$0.29678
CSI – Solar Thermal Exemption (per therm)	--	-$0.00157
Care Discount	n/a	-$0.14124
Total G1-NGV or GL1-NGV Schedule Charge1/	**$0.76765**	**$0.56496**
Schedule G-PPPS (Public Purpose Program Surcharge)1/ (per therm)	$0.06551	$0.04370

1/Schedule G-PPPS needs to be added to the Total Charge for bill calculation. See Schedule G-PPPS.

This rate schedule applies to natural gas service to Core End-Use Customers on PG&E's Transmission and/or Distribution Systems. Service on this schedule is an option to those customers for whom Schedule G-1 or GL-1 applies** and is for residential use where a Natural Gas Vehicle (NGV) has been leased or purchased and a home refueling appliance (HRA) has been installed for the sole purpose of compressing natural gas for use as a motor-vehicle fuel for the personal vehicle(s) owned or leased by the customer served under this rate schedule. Compression of natural gas to the pressure required for its use as motor-vehicle fuel will be performed by the Customer's equipment at the Customer's designated premises only.

Schedule G1-NGV and GL1-NGV applies everywhere within PG&E's natural gas Service Territory. Customers are responsible for federal and state taxes applicable to fuels for vehicular use.

Certification
In order to receive service under this rate schedule, customers must provide a Natural Gas Home Refueling Appliance Certification (Form No. 79-1047) to PG&E.

Surcharges
Customers served under this schedule in conjunction with Schedule G-CT, or in conjunction with noncore service, are subject to a franchise fee surcharge under Schedule G-SUR for gas volumes purchased from parties other than PG&E and transported by PG&E. Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

Alternate Procurement Service
Customers may procure gas supply from a party other than PG&E by taking service on this schedule in conjunction with Schedule G-CT – Core Gas Aggregation Service. Customers who procure their own gas supply will not pay the Procurement Charge component on this rate schedule shown above and will be subject to the applicable rates specified in Schedule G-CT.

**Schedule GL-1 applies to applicants who qualify for California Rates for Energy (CARE) under the eligibility and certification criteria set forth in Rules 19.1, 19.2, or 19.3.

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Core Commercial Gas Rates

Rates below are effective October 1, 2013, through October 31, 2013.

Small Commercial: Schedule G-NR1 (Usage less than 20,800 therms per month)*

	Highest Average Daily Usage**				
	0 - 5.0 Therms	5.1 - 16.0 Therms	16.1 - 41.0 Therms	41.1 - 123.0 Therms	123.1 & Up Therms
Customer Charge (per day)	$0.27048	$0.52106	$0.95482	$1.66489	$2.14936
		Per Therm			
		Summer		Winter	
		First 4,000 Therms	Excess Therms	First 4,000 Therms	Excess Therms
Procurement Charge (per therm)		$0.40599	$0.40599	$0.40599	$0.40599
Transportation Charge (per therm)		$0.31629	$0.14837	$0.38898	$0.18247
Total G-NR1 Schedule Charge[1/]		**$0.72228**	**$0.55436**	**$0.79497**	**$0.58846**
Schedule G-PPPS (Public Purpose Program Surcharge)[1/] (per therm)		$0.03878	$0.03878	$0.03878	$0.03878

*Excluding months during which usage is less than 200 therms.

**Based on customer's highest Average Daily Usage (ADU) determined from among the billing periods occurring within the last twelve months, including 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.

Large Commercial: Schedule G-NR2 (Usage greater than 20,800 therms per month)*

	Per Day	Per Therm			
		Summer		Winter	
		First 4,000 Therms	Excess Therms	First 4,000 Therms	Excess Therms
Customer Charge	$4.95518				
Procurement Charge		$0.37699	$0.37699	$0.37699	$0.37699
Transportation Charge		$0.31629	$0.14837	$0.38898	$0.18247
Total G-NR2 Schedule Charge[1/]		**$0.69328**	**$0.52536**	**$0.76597**	**$0.55946**
Schedule G-PPPS (Public Purpose Program Surcharge)[1/]		$0.07137	$0.07137	$0.07137	$0.07137

*Excluding months during which usage is less than 200 therms.

[1/]Schedule G-PPPS needs to be added to the Total Charge for bill calculation. Prior to April 1, 2005, the transportation rate included the PPP surcharge mandated by state. Effective April 1, 2005, gas PPP surcharges are removed from gas transportation rates. See Schedule G-PPPS for details and CARE rate.

G-NR1 and G-NR2 Seasons:
Summer: April 1 through Oct. 31
Winter: November 1 through March 31

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Core Gas Aggregation Rates

Core Gas Aggregation Service: Schedule G-CT

Schedule G-CT applies to transportation of natural gas for Core End-Use Customers who aggregate their gas volumes and who obtain natural gas supply service from a source other than PG&E. The provisions of Schedule G-CT apply to Core End-Use Customers and to the party who supplies them with natural gas and provides or obtains services necessary to deliver such gas to PG&E's Distribution System. Rule 23 (Tariff Book) also sets forth terms and conditions applicable to Core Gas Aggregation Service.

A group of Core End-Use Customers who aggregate their gas volumes comprise a Core Transport Group (Group). The minimum aggregate gas volume for a Group is 12,000 decatherms per year. The Customer must designate a Core Transport Agent (CTA), who is responsible for providing gas aggregation services to Customers in the Group as described in Rule 23. Aggregation of multiple loads at a single facility or aggregation of loads at multiple facilities shall not change the otherwise-applicable rate schedule for a specific facility. Customers electing service under this schedule must request such service for one hundred percent of the core load served by the meter. Schedule G-CT must be taken in conjunction with a core rate schedule.

Core volumes are eligible for service under this schedule, whether or not noncore volumes are also delivered to the same premises. However, core volumes cannot be aggregated with noncore volumes in order to meet the minimum therm requirement for noncore service. Service to core volumes associated with noncore volumes under this schedule applies to all core volumes on the noncore premises.

CTAs, on behalf of a Group, may receive service on PG&E's Backbone Transmission System by utilizing Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA.

Rates

Customers taking service under Schedule G-CT will receive and pay for service under their otherwise-applicable core rate schedule in addition to the rate shown below, except that Customers who procure their own gas supply do not pay the Procurement Charge specified on their otherwise-applicable core rate schedule.

Additional Charges

Pursuant to Schedule G-SUR, Customers will be subject to a franchise fee surcharge for gas volumes purchased from parties other than PG&E and transported by PG&E. Customers are also responsible for any applicable costs, taxes and/or fees incurred by PG&E in receiving gas to be delivered to such Customers.

See Schedule G-CT for further details.

Natural Gas Vehicle Rates

The Schedule G-NGV1 and G-NGV2 rates shown below are effective October 1, 2013, through October 31, 2013.

Natural Gas Service For Compression On Customer's Premises: Schedule G-NGV1 (Rates change monthly)

Schedule G-NGV1 applies to the sale of uncompressed natural gas for the sole purpose of compressing it for use as a motor-vehicle fuel. Compression of natural gas to the pressure required for its use as motor-vehicle fuel will be performed by the Customer's equipment at the Customer's designated premises only.

	PER DAY	PER THERM
Customer Charge	$0.44121	
Procurement Charge		$0.36734
Transportation Charge		$0.14207
Total G-NGV1 Schedule Charge		**$0.50941**
Schedule G-PPPS (Public Purpose Program Surcharge)1/		$0.02408

Note: The gas procurement charge and total rates generally change on the 1st day of each month. (Transportation rates do not change monthly.) See Schedule G-NGV1 for further details.

Compressed Natural Gas Service on PG&E's Premises: Schedule G-NGV2 (Rates change monthly)

Schedule G-NGV2 applies to the sale of compressed natural gas (CNG) at PG&E-owned natural gas fueling stations to customers who use CNG as a motor fuel.

	PER MONTH	PER THERM
Procurement Charge		$0.36734
Transportation Charge		$1.39658
Total G-NGV2 Schedule Charge		**$1.76392**
Per Gasoline Gallon Equivalent		$2.25076
Schedule G-PPPS (Public Purpose Program Surcharge)1/		$0.02408

Note: The gas procurement charge and total rates generally change on the 5th business day of each month. (Transportation rates do not change monthly.) See Schedule G-NGV2 for further details.

1/Schedule G-PPPS needs to be added to the Total Charge for bill calculation.

Noncore Natural Gas Service for Compression on Customers' Premises: Schedule G-NGV4

Schedule G-NGV4 applies to the transportation of natural gas to customer-owned natural gas vehicle fueling stations on PG&E's Backbone, Local Transmission and/or Distribution Systems. To qualify for service 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. Customers must procure gas supply from a supplier other than PG&E.

Rates

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

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 therms	$1.93578
5,001 to 10,000 therms	$5.76658
10,001 to 50,000 therms	$10.73293
50,001 to 200,000 therms	$14.08570
200,001 to 1,000,000 therms	$20.43715
1,000,001 therms and above	$173.35956

Transportation Charge

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

Backbone-Level Rate:

Applies to Backbone Level End-Use Customers as defined in Rule 1.

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).

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.

Backbone (per therm)	$0.01592				
Transmission (per therm)	$0.04460				
Distribution (per therm)	**Tier 1**	**Tier 2**	**Tier 3**	**Tier 4**	**Tier 5**
Average Monthly Use	**0-20,833 therms**	**20,834-49,999 therms**	**50,000-166,666 therms**	**166,667-249,999 therms**	**250,000 and above**
Summer	$0.18039	$0.13032	$0.12009	$0.11209	$0.04460
Winter	$0.22873	$0.16114	$0.14733	$0.13653	$0.04460

Summer Season: April 1 through October 31 Winter Season: November 1 through March 31

Customers on this schedule are subject to Schedule G-PPPS, a gas Public Purpose Program Surcharge, as shown below. See Schedule G-PPPS for details.

Public Purpose Program Surcharge (per therm)

DISTRIBUTION/TRANSMISSION
$0.02408

Additional Charges

Customers may pay a franchise fee surcharge for gas volumes transported by PG&E (See Schedule G-SUR for details.) Customers are 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. See Schedule G-NGV4 for details.

Gas Public Purpose Program Surcharge

The Schedule G-PPPS Surcharge rates shown below are effective January 1, 2013 through December 31, 2013.

Public Purpose Program Surcharge: Schedule G-PPPS

Pursuant to Public Utility (PU) Code Sections 89-0900, this schedule applies a gas Public Purpose Program (PPP) surcharge to gas transportation volumes under the rate schedules specified below. The gas PPP surcharge is collected to fund gas energy efficiency and low-income energy efficiency programs, the California Alternate Rates for Energy (CARE) low-income assistant program, and public interest research and development. Under PU Code Section 896, certain customers are exempt from the gas PPP surcharge as described in the Exempt Customer section, below.

Rates

The following surcharges apply to natural gas service for eligible Core and Noncore End-Use Customers.

CUSTOMER CLASS (RATE SCHEDULE):	PER THERM (NON-CARE)	PER THERM (CARE)
Residential: (G-1, G1-NGV, GM, GS, GT, GL-1, GL1-NGV, GML, GSL, and GTL)	$0.06551	$0.04370
Small Commercial: (G-NR1)	$0.03878	$0.01697
Large Commercial: (G-NR2)	$0.07137	$0.04956
Natural Gas Vehicle: (G-NGV1/G-NGV2/G-NGV4)	$0.02408	n/a
Industrial: (G-NT - Distribution)	$0.03568	n/a
Industrial: (G-NT – Backbone/Transmission)	$0.02990	n/a
Liquid Natural Gas (G-LNG)	$0.02408	n/a

Exempt Customers

In accordance with PU Code Section 896, certain customers are exempt from Schedule G-PPPS. These include:

a. All gas consumed by customer's served under Schedules G-EG and G-WSL;
b. All gas consumed by Enhanced Oil Recovery (EOR) facilities;
c. All gas consumed by customers in which the State of California is prohibited from taxing under the United States Constitution or the California Constitution, consistent with California Energy Resources Surcharge Regulations 2315 and 2316, as described in Publication No. 11 issued by the California State Board of Equalization (BOE), which include:

Public Purpose Program Surcharge (cont'd)

1. The United States, its unincorporated agencies and instrumentalities;
2. Any incorporated agency of instrumentality of the United States wholly owned by either the United States or by a corporation wholly owned by the United States;
3. The American National Red Cross, its chapters and branches;
4. Insurance companies, including title insurance companies, subject to taxation under California Constitution, Article XIII, Section 28, or it's successor;
5. Enrolled Indians purchasing and consuming natural gas on Indian reservations; and
6. Federal Credit unions organized in accordance with the provisions of the Federal Credit Union Act.

Exempt Customer Bill Adjustments:
PG&E will annually review its customer accounts and make appropriate bill adjustments to return any surcharge amounts received from exempt customers, plus applicable interest, within 30 days after identification of such exempt customers, unless previously refunded from the State Treasury. PG&E will inform BOE of any refunds issued to customers.

See Schedule G-PPPS for further details.

II - Noncore Gas Rates

Gas Franchise Fee Surcharge

The Schedule G-SUR Franchise Fee Surcharge rate shown below is effective October 1, 2013, through October 31, 2013.

Customer-Procured Gas Franchise Fee Surcharge: Schedule G-SUR (Rate changes monthly)

Pursuant to California State Senate Bill No. 278 (1993), Schedule G-SUR applies to all gas volumes procured by Customers from third-party entities and transported by PG&E with the following exceptions:

a) the State of California or a political subdivision thereof;
b) one gas utility transporting gas for end-use in its Commission-designated service area through another utility's service area;
c) a utility transporting its own gas through its own gas transmission and distribution system for purposes of generating electricity or for use in its own operations;
d) cogeneration Customers, for that quantity of natural gas billed under Schedule G-EG.

Surcharge Recovery
The surcharge will be shown on the Customer's monthly bill based on volumes procured by the Customer from a third-party gas supplier and transported by PG&E (metered usage).

Rates
The G-SUR surcharge changes on a monthly basis and is comprised of the following components:

	PER THERM
a. the monthly core Weighted Average Cost of Gas (WACOG) , exclusive of Storage Costs, Franchise Fees and Uncollectibles, which is multiplied by	$0.28786
b. the Franchise Fee factor* adopted in PG&E's most recent General Rate Case, which is	0.009886
The Schedule G-SUR Franchise Fee Surcharge is effective October 1, 2013, through October 31, 2013.	$0.00285

*Does not include Uncollectibles factor of 0.003145.

See Schedule G-SUR for further details.

III - Gas Transportation Rates

Gas Transportation Service to Noncore End-Use Customers: Schedule G-NT

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

Rates

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

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 therms	$1.93578
5,001 to 10,000 therms	$5.76658
10,001 to 50,000 therms	$10.73293
50,001 to 200,000 therms	$14.08570
200,001 to 1,000,000 therms	$20.43715
1,000,001 therms and above	$173.35956

Transportation Charge

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

Transmission-Level Rate:

Apply to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi).

Distribution-Level Rate:

Apply 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.

Backbone (per therm)	$0.01592				
Transmission (per therm)	$0.05087				
Distribution (per therm)	**Tier 1**	**Tier 2**	**Tier 3**	**Tier 4**	**Tier 5**
Average Monthly Use	**0-20,833 therms**	**20,834-49,999 therms**	**50,000-166,666 therms**	**166,667-249,999 therms**	**250,000 and above***
Summer	$0.18039	$0.13032	$0.12009	$0.11209	$0.05087
Winter	$0.22873	$0.16114	$0.14733	$0.13653	$0.05087

Summer Season: April 1 through October 31 Winter Season: November 1 through March 31

Customers on this schedule are subject to Schedule G-PPPS, a gas Public Purpose Program Surcharge, as shown below. See Schedule G-PPPS for details.

Public Purpose Program Surcharge (per therm)

BACKBONE/TRANSMISSION	DISTRIBUTION
$0.02990	$0.03568

Additional Charges

Customers may pay a franchise fee surcharge for gas volumes transported by PG&E (See Schedule G-SUR for details.) Customers are 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. See Schedule G-NT for further details.

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Gas Transportation Service to Electric Generation: Schedule G-EG

Schedule G-EG 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; and (c) solar electric generation plants, defined herein.

This schedule does not apply to gas transported to non-electric generation loads.
Customers on Schedule G-EG with generating capacity 500 kilowatts or larger, or with gas usage in excess of 250,000 therms per year must procure gas supply from a third-party gas supplier, not from a Core Procurement Group.

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

Rates

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

Customer Access Charge

The applicable Per-Day Customer Access Charges is based on the Customer's Average Monthly Usage, as defined in Gas Rule 1 (see Tariff Book, Gas Rule 1). Usage through multiple noncore gas meters on a single premise 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	$1.93578
5,001 to 10,000 therms	$5.76658
10,001 to 50,000 therms	$10.73293
50,001 to 200,000 therms	$14.08570
200,001 to 1,000,000 therms	$20.43715
1,000,001 therms and above	$173.35956

Transportation Charge

	BACKBONE	ALL OTHER CUSTOMERS
Transportation Charge (per therm)	$0.01566	$0.04434

Customers may be required to pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details).

Additional Charges

Customers are responsible for any other applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of gas supplied from a source other than PG&E from intra- or interstate sources.

See Schedule G-EG for further details.

Gas Transportation to Wholesale/Resale Customers and Gas Balancing Service

Gas Transportation Service to Wholesale/Resale Customers: Schedule G-WSL

Schedule G-WSL applies to the transportation of natural gas for resale. Schedule G-WSL is available to the Customers listed below, and any new wholesale Customer. Customers must procure gas supply from a supplier other than PG&E.

Rates

Customers pay a Customer Access Charge and a Transportation Charge.

	PALO ALTO	COALINGA	WEST COAST GAS-MATHER		ISLAND ENERGY	ALPINE NATURAL GAS	WEST COAST GAS-CASTLE
Customer Access Charge (per day)	$151.77205	$45.51945	$24.16438		$30.84132	$10.29238	$26.44208
	Trans.	**Trans.**	**Trans.**	**Dist.**	**Trans.**	**Trans.**	**Dist.**
Transportation Charge (per therm)	$0.03844	$0.03844	$0.03844	$0.17242	$0.03844	$0.03844	$0.13962

Existing Wholesale Customers will have a one-time option prior to June 1, 2011, to subscribe, on behalf of their core Customers, for firm capacity on the Redwood to on-system and Baja to on-system paths as specified below. Capacity will be offered only for the core portion of the Customer's load. See Rate Schedule G-WSL for further details.

CUSTOMER	REDWOOD (MDTH)	BAJA - ANNUAL (MDTH)	BAJA - SEASONAL (MDTH)
Alpine	0.098	0.056	0.052
Coalinga	0.552	0.316	0.291
Island Energy	0.064	0.037	0.034
Palo Alto	5.898	3.372	3.110
West Coast Gas (Castle)	0.051	0.029	0.027
West Coast Gas (Mather)	0.171	0.098	0.090

Additional Charges

Customers are responsible for any other applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

See Schedule G-WSL for further details.

Gas Balancing Service for Intrastate Transportation Customers: Schedule G-BAL

Under Schedule G-BAL, PG&E will calculate, maintain and carry imbalances; provide incentives for Customers to avoid and minimize imbalances, facilitate elimination of imbalances; and cash out imbalances. Schedule G-BAL applies to PG&E's Core Procurement Department for transactions on behalf of PG&E's core procurement Customers, and to all Customers taking service under Schedules G-CT (or other core rate schedule(s) where procurement service is provided by a third party), to Schedules G-NT, G-EG, G-NGV4, G-WSL, G-AFT, G-SFT, G-NFT, G-AA, G-NAA, G-AFTOFF, G-AAOFF, G-NFTOFF, G-NAAOFF, G-PARK, and G-LEND.

See Schedule G-BAL for further details.

Firm Transportation On-System Rates

Annual Firm Transportation On-System: Schedule G-AFT

Schedule G-AFT applies to firm gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under G-AFT is available only for the transportation of natural gas within PG&E's service territory on the paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AFT are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities, or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point(s) to which gas is transported under this rate schedule must be an On- System Delivery Point.

Rates
The Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, as specified in the Customer's Service Agreement.

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

PATH	RESERVATION RATE (PER DECATHERM PER MONTH)	
	MFV Rates	SFV Rates
Redwood to On-System	$5.2084	$7.9034
Redwood to On-System (Core Procurement Groups only)	$4.4923	$6.3001
Baja to On-System	$5.8953	$8.9457
Baja to On-System (Core Procurement Groups only)	$5.2276	$7.3313
Silverado to On-System (including Core Procurement Groups)	$3.1425	$4.4150
Mission to On-System (including Core Procurement Groups)	$3.1425	$4.4150

Annual Firm Transportation On-System: Schedule G-AFT (cont'd)

Usage Charge

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

PATH	USAGE RATE (PER DECATHERM)	
	MFV Rates	SFV Rates
Redwood to On-System	$0.0965	$0.0079
Redwood to On-System (Core Procurement Groups only)	$0.0685	$0.0091
Baja to On-System	$0.1090	$0.0087
Baja to On-System (Core Procurement Groups only)	$0.0794	$0.0102
Silverado to On-System (including Core Procurement Groups)	$0.0495	$0.0077
Mission to On-System (including Core Procurement Groups)	$0.0495	$0.0077
Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only)	$0.0000	$0.0000

Additional Charges

The Customer is responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AFT for further details.

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Firm Transportation Off-System Rates

Annual Firm Transportation Off-System: Schedule G-AFTOFF

Schedule G-AFTOFF applies to firm gas transportation service on PG&E's Backbone Transmission System to the Off-System Delivery Points. Schedule G-AFTOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below for off-system deliveries. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AFTOFF are as follows:

Path	Receipt Point(s)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Firm Off-System Delivery Points
Kern River Station to Southern California Gas Company
Fremont Peak to Kern River Gas Transmission

Backhaul Off-System Points
All off-system interconnection points are available as backhaul delivery points under this schedule if the upstream pipeline accepts backhaul nominations. Backhaul service is limited to the quantities of gas being delivered from the upstream pipeline.

Alternative Delivery Points
If the Customer elects the Modified Fixed Variable (MFV) rate structure under Schedule G-AFTOFF, the Delivery Point under this schedule shall be limited to a Firm Off-System Delivery Point. If the Customer elects the Straight Fixed Variable (SFV) rate structure under G-AFTOFF, the Customer may specify an On-System Delivery Point within the transmission path contracted by Customer as an alternate delivery point.

Rates
The Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will be specified in the Customer's Service Agreement.

Annual Firm Transportation Off-System: Schedule G-AFTOFF (cont'd)

Reservation Charge

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

PATH	RESERVATION RATE (PER DECATHERM PER MONTH)	
	MFV Rates	SFV Rates
Redwood to Off-System	$5.2084	$7.9034
Baja to Off-System	$5.8953	$8.9457
Silverado to Off-System	$5.2084	$7.9034
Mission to Off-System	$5.2084	$7.9034

Usage Charge

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

PATH	USAGE RATE (PER DECATHERM)	
	MFV RATES	SFV RATES
Redwood to Off-System	$0.0965	$0.0079
Baja to Off-System	$0.1090	$0.0087
Silverado to Off-System	$0.0965	$0.0079
Mission to Off-System	$0.0965	$0.0079

Additional Charges

The Customer is responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AFTOFF for further details.

Seasonal Firm Transportation On-System Rates

Seasonal Firm Transportation On-System: Schedule G-SFT

Schedule G-SFT applies to the seasonal firm gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-SFT is available only for the transportation of natural gas within PG&E's service territory on the paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-SFT are as follows:

Path	Receipt Point(s)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)

Any Delivery Point(s) to which gas is transported under this rate schedule must be an On- System Delivery Point.

Rates

The Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will be specified in the Customer's Service Agreement.

Reservation Charge

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

Path	Reservation Rate (per decatherm per month)	
	MFV Rates	SFV Rates
Redwood to On-System	$6.2501	$9.4840
Baja to On-System	$7.0744	$10.7348
Baja to On-System (Core Procurement Groups only)	$6.2731	$8.7976
Silverado to On-System	$3.7710	$5.2980
Mission to On-System	$3.7710	$5.2980

Seasonal Firm Transportation On-System: Schedule G-SFT (cont'd)

Usage Charge

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

PATH	USAGE RATE (PER DECATHERM)	
	MFV RATES	SFV RATES
Redwood to On-System	$0.1159	$0.0095
Baja to On-System	$0.1308	$0.0104
Baja to On-System (Core Procurement Groups only)	$0.0952	$0.0122
Silverado to On-System	$0.0594	$0.0092
Mission to On-System	$0.0594	$0.0092

Additional Charges

The Customer is responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

For purposes of this rate schedule there are two (2) seasons per year, Winter and Summer. The Winter season extends for five (5) months, beginning November 1 and ending April 31. The Summer season extends for seven (7) months, beginning April 1 and ending October 31.

See Schedule G-SFT for further details.

As-Available Transportation On-System Rates

As-Available Transportation On-System: Schedule G-AA

Schedule G-AA applies to As-available gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-AA is available only for the transportation of natural gas within PG&E's service territory on the paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AA are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)

Any Delivery Point(s) to which gas is transported under this rate schedule must be an On- System Delivery Point.

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.

Usage Charge

PATH	USAGE RATE (PER DECATHERM)
Redwood to On-System	$0.3213
Baja to On-System	$0.3633
Silverado to On-System	$0.1834
Mission to On-System	$0.0000

Additional Charges

The Customer is responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AA for further details.

As-Available Transportation Off-System Rates

As-Available Transportation Off-System: Schedule G-AAOFF

Schedule G-AAOFF applies to As-available gas transportation service on PG&E's Backbone Transmission System to Off-System Delivery Point(s) only. Schedule G-AAOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AAOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)

Any Delivery Point(s) to which gas is transported under this rate schedule must be an Off-System Delivery Point.

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.

Usage Charge

PATH	USAGE RATE (PER DECATHERM)
Redwood to Off-System	$0.3213
Baja to Off-System	$0.3633
Silverado to Off-System	$0.3213
Mission to Off-System	$0.3213
Mission to Off-System Storage Withdrawals	$0.0000

Additional Charges

The Customer is responsible for payment of any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AAOFF for further details.

Negotiated Firm Transportation On-System Rates

Negotiated Firm Transportation On-System: Schedule G-NFT

Schedule G-NFT applies to the firm gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only, at negotiated rates. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or, a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-NFT is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NFT are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point(s) to which gas is transported under this rate schedule must be an On-System Delivery Point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under Schedule G-NFT will be capped at 120 percent of the tariffed rate under Schedule G-AFT for a particular path, as follows: the negotiated rate (including all surcharges, costs and/or fees), converted to a volumetric-only rate at 100 percent load factor, shall be no greater than 120 percent of the Schedule G-AFT tariffed rate (including all surcharges, costs and/or fees), converted to a volumetric-only rate at 100 percent load factor under the Modified Fixed Variable (MFV) rate structure.

At PG&E's sole option, firm On-System capacity may be available under Schedule G-NFT at less than the rates under Schedule G-AFT. At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted.
The Customer is 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.

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Negotiated Firm Transportation Off-System: Schedule G-NFTOFF (cont'd)

To transport storage withdrawals On-System, Customers may convert all or part of a Firm On-System Redwood or Firm On-System Baja Exhibit to a Firm On-System Mission Exhibit at any time prior to 60 minutes before the close of the Timely Nomination Cycle, as set forth in Gas Rule 21. The negotiated transmission rate for this Mission Path service shall, unless otherwise agreed to, be zero. However, the full monthly demand charge is still applicable. Conversions of Firm On-System Baja Exhibits are limited to the amount of unsold Firm Redwood capacity available at the time of the requested conversion. Baja Exhibit conversions may be requested on a monthly basis, no more than five days prior to the end of the month, for a maximum term of one month. Redwood Exhibit conversions have no minimum term limit. See Rate Schedule G-NFT for further details.

Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule
G-BAL (see Tariff Book).

See Schedule G-NFT for further details.

Negotiated Firm Transportation Off-System Rates

Negotiated Firm Transportation Off-System: Schedule G-NFTOFF

Schedule G-NFTOFF applies to firm gas transportation service on PG&E's Backbone Transmission System to the Off-System Delivery Points at negotiated rates. Service under Schedule G-NFTOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below for off-system deliveries. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NFTOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Firm Off-System Delivery Points
Kern River Station to Southern California Gas Company
Fremont Peak to Kern River Gas Transmission

Backhaul Off-System Points
All off-system interconnection points are available as backhaul delivery points under this schedule if the upstream pipeline accepts backhaul nominations. Backhaul service is limited to the quantities of gas being delivered from the upstream pipeline.

Alternative Delivery Points
The Delivery Point to which gas is transported under this rate schedule shall be a Firm Off-System Delivery Point, unless the Customer elects both the Straight Fixed Variable (SFV) rate structure and the maximum allowable rate under G-NFTOFF. If the above conditions are met, the Customer may specify an On-System Delivery Point within the transmission path contracted by Customer as al alternative delivery point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under Schedule G-NFTOFF will be capped at 120 percent of the Schedule G-AFTOFF tariffed rate for a particular path, as follows: the negotiated rate (including all surcharges, costs and/or fees), converted to a volumetric-only rate at 100 percent load factor, shall be no greater than 120 percent of the Schedule G-AFTOFF tariffed rate (including all surcharges, costs and/or fees), converted to a volumetric-only rate at 100 percent load factor under the Modified Fixed Variable (MFV) rate structure.

Negotiated Firm Transportation Off-System: Schedule G-NFTOFF (cont'd)

At PG&E's sole option, firm Off-System capacity may be available on G-NFTOFF at less than the rates in Schedule G-AFTOFF. At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted.

The Customer is 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. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-NFTOFF for further details.

Negotiated As-Available Transportation On-System Rates

Negotiated As-Available Transportation On-System: Schedule G-NAA

Schedule G-NAA applies to As-available gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only, at negotiated rates. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or, a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for the further transportation and delivery of natural gas to an Off-System Delivery Point, one of the following rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-NAA is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NAA are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point to which gas is transported under this rate schedule must be an On-System Delivery Point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under Schedule G-NAA will be capped at 120 percent of the tariffed rate under Schedule G-AA for a particular path. At PG&E's sole option, As-available On-System capacity may be available under Schedule G-NAA at less than the rates under Schedule G-AA.

At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted. The Customer is 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.

See Schedule G-NAA for further details.

Negotiated As-Available Transportation Off-System Rates

Negotiated As-Available Transportation Off-System: Schedule G-NAAOFF

Schedule G-NAAOFF applies to As-available gas transportation service on PG&E's Backbone Transmission System to Off-System Delivery Point(s), at negotiated rates. Schedule G-NAAOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below for off-system deliveries. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NAAOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point to which gas is transported under this rate schedule must be an Off-System Delivery Point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under G-NAAOFF will be capped at 120 percent of the tariffed rate under Schedule G-AAOFF for a particular path. At PG&E's sole option, as-available off-system capacity may be available hereunder at less than the rates under Schedule G-AAOFF.

At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted. The Customer is 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.

See Schedule G-NAAOFF for further details.

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 1

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* CORE p. 1

	RESIDENTIAL							
	G-1, GM, GS, GT				GL-1, GML, GSL, GTL			
	Baseline		Excess		Baseline		Excess	
CORE FIXED COST ACCOUNT – DISTRIBUTION COST SUBACCOUNT (1)**	0.38327		0.70017		0.38327		0.70017	
CORE FIXED COST ACCOUNT – CORE COST SUBACCOUNT	0.00658		0.00658		0.00658		0.00658	
CFCA - ARB AB 32 COI	0.00309		0.00309		0.00309		0.00309	
CARE DISCOUNT	0.00000		0.00000		(0.19191)	(R)	(0.25529)	(R)
LOCAL TRANSMISSION	0.04241		0.04241		0.04241		0.04241	
CPUC FEE	0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		0.00157		0.00000		0.00000	
CEE INCENTIVE	0.00162		0.00162		0.00162		0.00162	
SMARTMETER™ PROJECT – GAS	0.03759		0.03759		0.03759		0.03759	
WGSP – TRANSPORTATION	0.02751		0.02751		0.02751		0.02751	
CORE IMPLEMENTATION PLAN – LT	0.02024		0.02024		0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327		0.00327		0.00327		0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033		0.00033		0.00033		0.00033	
WGSP – PROCUREMENT	0.01894		0.01894		0.01894		0.01894	
WINTER HEDGING	0.00338	(I)	0.00338	(I)	0.00338	(I)	0.00338	(I)
CORE BROKERAGE FEE	0.00250		0.00250		0.00250		0.00250	
CORE FIRM STORAGE	0.01977	(I)	0.01977	(I)	0.01977	(I)	0.01977	(I)
SHRINKAGE	0.01036	(R)	0.01036	(R)	0.01036	(R)	0.01036	(R)
CAPACITY CHARGE	0.09139	(I)	0.09139	(I)	0.09139	(I)	0.09139	(I)
CORE PROCUREMENT CHARGE (2)**	0.28662	(R)	0.28662	(R)	0.28662	(R)	0.28662	(R)
TOTAL RATE	0.96113	(I)	1.27803	(I)	0.76765	(I)	1.02117	(I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 2

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

	RESIDENTIAL NGV			
	G1-NGV		GL1-NGV	
CORE FIXED COST ACCOUNT – DISTRIBUTION COST SUBACCOUNT (1)**	0.15188		0.15188	
CORE FIXED COST ACCOUNT – CORE COST SUBACCOUNT	0.00658		0.00658	
CFCA - ARB AB 32 COI	0.00309		0.00309	
CARE DISCOUNT	0.00000		(0.14124)	(R)
LOCAL TRANSMISSION	0.04241		0.04241	
CPUC FEE	0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		0.00000	
CEE INCENTIVE	0.00162		0.00162	
SMARTMETER™ PROJECT – GAS	0.03759		0.03759	
WGSP – TRANSPORTATION	0.02751		0.02751	
CORE IMPLEMENTATION PLAN – LT	0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327		0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033		0.00033	
WGSP – PROCUREMENT	0.01894		0.01894	
WINTER HEDGING	0.00338	(I)	0.00338	(I)
CORE BROKERAGE FEE	0.00250		0.00250	
CORE FIRM STORAGE	0.01664	(I)	0.01664	(I)
SHRINKAGE	0.01036	(R)	0.01036	(R)
CAPACITY CHARGE	0.07255	(I)	0.07255	(I)
CORE PROCUREMENT CHARGE (2)**	0.28662	(R)	0.28662	(R)
TOTAL RATE	0.70777	(I)	0.56496	(I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

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

SMALL COMMERCIAL

G-NR1

	Summer		Winter	
	First 4,000 Therms	Excess	First 4,000 Therms	Excess
CORE FIXED COST ACCOUNT – DISTRIBUTION COST SUBACCOUNT (1)**	0.20953	0.04161	0.28222	0.07571
CORE FIXED COST ACCOUNT – CORE COST SUBACCOUNT	0.00658	0.00658	0.00658	0.00658
CFCA - ARB AB 32 COI	0.00309	0.00309	0.00309	0.00309
LOCAL TRANSMISSION	0.04241	0.04241	0.04241	0.04241
CPUC FEE	0.00069	0.00069	0.00069	0.00069
CSI- SOLAR THERMAL PROGRAM	0.00157	0.00157	0.00157	0.00157
CEE INCENTIVE	0.00064	0.00064	0.00064	0.00064
SMARTMETER™ PROJECT – GAS	0.02289	0.02289	0.02289	0.02289
WGSP – TRANSPORTATION	0.00505	0.00505	0.00505	0.00505
CORE IMPLEMENTATION PLAN – LT	0.02024	0.02024	0.02024	0.02024
CORE IMPLEMENTATION PLAN – BB	0.00327	0.00327	0.00327	0.00327
CORE IMPLEMENTATION PLAN - STORAGE	0.00033	0.00033	0.00033	0.00033
WGSP – PROCUREMENT	0.00661	0.00661	0.00661	0.00661
WINTER HEDGING	0.00338 (I)	0.00338 (I)	0.00338 (I)	0.00338 (I)
CORE BROKERAGE FEE	0.00250	0.00250	0.00250	0.00250
CORE FIRM STORAGE	0.01725 (I)	0.01725 (I)	0.01725 (I)	0.01725 (I)
SHRINKAGE	0.01036 (R)	0.01036 (R)	0.01036 (R)	0.01036 (R)
CAPACITY CHARGE	0.07927 (I)	0.07927 (I)	0.07927 (I)	0.07927 (I)
CORE PROCUREMENT CHARGE (2)**	0.28662 (R)	0.28662 (R)	0.28662 (R)	0.28662 (R)
TOTAL RATE	0.72228 (I)	0.55436 (I)	0.79497 (I)	0.58846 (I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

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

LARGE COMMERCIAL

G-NR2

	Summer		Winter	
	First 4,000 Therms	Excess	First 4,000 Therms	Excess
CORE FIXED COST ACCOUNT – DISTRIBUTION COST SUBACCOUNT (1)**	0.22841	0.06049	0.30110	0.09459
CORE FIXED COST ACCOUNT – CORE COST SUBACCOUNT	0.00658	0.00658	0.00658	0.00658
CFCA - ARB AB 32 COI	0.00309	0.00309	0.00309	0.00309
LOCAL TRANSMISSION	0.04241	0.04241	0.04241	0.04241
CPUC FEE	0.00069	0.00069	0.00069	0.00069
CSI- SOLAR THERMAL PROGRAM	0.00157	0.00157	0.00157	0.00157
CEE INCENTIVE	0.00013	0.00013	0.00013	0.00013
SMARTMETER™ PROJECT – GAS	0.00768	0.00768	0.00768	0.00768
WGSP – TRANSPORTATION	0.00189	0.00189	0.00189	0.00189
CORE IMPLEMENTATION PLAN – LT	0.02024	0.02024	0.02024	0.02024
CORE IMPLEMENTATION PLAN – BB	0.00327	0.00327	0.00327	0.00327
CORE IMPLEMENTATION PLAN - STORAGE	0.00033	0.00033	0.00033	0.00033
WGSP – PROCUREMENT	0.00746	0.00746	0.00746	0.00746
WINTER HEDGING	0.00338 (I)	0.00338 (I)	0.00338 (I)	0.00338 (I)
CORE BROKERAGE FEE	0.00250	0.00250	0.00250	0.00250
CORE FIRM STORAGE	0.01246 (I)	0.01246 (I)	0.01246 (I)	0.01246 (I)
SHRINKAGE	0.01036 (R)	0.01036 (R)	0.01036 (R)	0.01036 (R)
CAPACITY CHARGE	0.05421 (I)	0.05421 (I)	0.05421 (I)	0.05421 (I)
CORE PROCUREMENT CHARGE (2)**	0.28662 (R)	0.28662 (R)	0.28662 (R)	0.28662 (R)
TOTAL RATE	0.69328 (I)	0.52536 (I)	0.76597 (I)	0.55946 (I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 5

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

CORE p. 5

	G-NGV1		G-NGV2	
CORE FIXED COST ACCOUNT – DISTRIBUTION COST SUBACCOUNT (1)**	0.04817		1.30268	
CORE FIXED COST ACCOUNT – CORE COST SUBACCOUNT	0.00658		0.00658	
CFCA - ARB AB 32 COI	0.00309		0.00309	
LOCAL TRANSMISSION	0.04241		0.04241	
CPUC FEE	0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		0.00157	
CEE INCENTIVE	0.00002		0.00002	
NGV BALANCING ACCOUNT	0.00000		0.00000	
SMARTMETER™ PROJECT – GAS	0.01570		0.01570	
CORE IMPLEMENTATION PLAN – LT	0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327		0.00327	
CORE IMPLEMENTATION PLAN – STORAGE	0.00033		0.00033	
WINTER HEDGING	0.00338	(I)	0.00338	(I)
CORE BROKERAGE FEE	0.00250		0.00250	
CORE FIRM STORAGE	0.01177	(I)	0.01177	(I)
SHRINKAGE	0.01036	(R)	0.01036	(R)
CAPACITY CHARGE	0.05271	(I)	0.05271	(I)
CORE PROCUREMENT CHARGE (2)**	0.28662	(R)	0.28662	(R)
TOTAL RATE	0.50941	(I)	1.76392	(I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 6

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

CORE p. 6

	G-CT (CORE TRANSPORT)					
	RESIDENTIAL		CARE RESIDENTIAL			
	Baseline	Excess	Baseline		Excess	
CORE FIXED COST ACCOUNT—DISTRIBUTION COST SUBACCOUNT (1) **	0.38327	0.70017	0.38327		0.70017	
CORE FIXED COST ACCOUNT—CORE COST SUBACCOUNT	0.00658	0.00658	0.00658		0.00658	
CFCA - ARB AB 32 COI	0.00309	0.00309	0.00309		0.00309	
CARE DISCOUNT	0.00000	0.00000	(0.19191)	(R)	(0.25529)	(R)
LOCAL TRANSMISSION	0.04241	0.04241	0.04241		0.04241	
CPUC FEE	0.00069	0.00069	0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157	0.00157	0.00000		0.00000	
CEE INCENTIVE	0.00162	0.00162	0.00162		0.00162	
SMARTMETER™ PROJECT – GAS	0.03759	0.03759	0.03759		0.03759	
WGSP—TRANSPORTATION	0.02751	0.02751	0.02751		0.02751	
CORE IMPLEMENTATION PLAN – LT	0.02024	0.02024	0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327	0.00327	0.00327		0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033	0.00033	0.00033		0.00033	
TOTAL RATE	0.52817	0.84507	0.33469	(R)	0.58821	(R)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 7

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)*(Cont'd.) CORE p. 7

	G-CT (CORE TRANSPORT) RESIDENTIAL– NGV		
	G1-NGV	GL1-NGV	
CORE FIXED COST ACCOUNT– DISTRIBUTION COST SUBACCOUNT (1)**	0.15188	0.15188	
CORE FIXED COST ACCOUNT– CORE COST SUBACCOUNT	0.00658	0.00658	
CORE FIXED COST ACCOUNT - ARB AB 32 COI	0.00309	0.00309	
CARE DISCOUNT	0.00000	(0.14124)	(R)
LOCAL TRANSMISSION	0.04241	0.04241	
CPUC FEE	0.00069	0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157	0.00000	
CEE INCENTIVE	0.00162	0.00162	
SMARTMETER™ PROJECT – GAS	0.03759	0.03759	
WGSP – TRANSPORTATION	0.02751	0.02751	
CORE IMPLEMENTATION PLAN – LT	0.02024	0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327	0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033	0.00033	
TOTAL RATE	0.29678	0.15397	(R)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 8

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

G-CT (CORE TRANSPORT)
SMALL COMMERCIAL

	Summer First 4,000 Therms		Summer Excess		Winter First 4,000 Therms		Winter Excess	
CORE FIXED COST ACCOUNT—DISTRIBUTION COST SUBACCOUNT (1) **	0.20953	(R)	0.04161	(I)	0.28222	(R)	0.07571	(I)
CORE FIXED COST ACCOUNT—CORE COST SUBACCOUNT	0.00658	(I)	0.00658	(I)	0.00658	(I)	0.00658	(I)
CFCA - ARB AB 32 COI	0.00309		0.00309		0.00309		0.00309	
LOCAL TRANSMISSION	0.04241	(I)	0.04241	(I)	0.04241	(I)	0.04241	(I)
CPUC FEE	0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		0.00157		0.00157		0.00157	
CEE INCENTIVE	0.00064	(R)	0.00064	(R)	0.00064	(R)	0.00064	(R)
SMARTMETER™ PROJECT – GAS	0.02289	(R)	0.02289	(R)	0.02289	(R)	0.02289	(R)
WGSP—TRANSPORTATION	0.00505		0.00505		0.00505		0.00505	
CORE IMPLEMENTATION PLAN – LT	0.02024		0.02024		0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327		0.00327		0.00327		0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033		0.00033		0.00033		0.00033	
TOTAL RATE	0.31629	(R)	0.14837	(I)	0.38898	(R)	0.18247	(I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 9

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

CORE p. 9

G-CT (CORE TRANSPORT)
LARGE COMMERCIAL

	Summer First 4,000 Therms		Summer Excess		Winter First 4,000 Therms		Winter Excess	
CORE FIXED COST ACCOUNT – DISTRIBUTION COST SUBACCOUNT (1)**	0.22841	(R)	0.06049	(I)	0.30110	(R)	0.09459	(I)
CORE FIXED COST ACCOUNT – CORE COST SUBACCOUNT	0.00658	(I)	0.00658	(I)	0.00658	(I)	0.00658	(I)
CFCA - ARB AB 32 COI	0.00309		0.00309		0.00309		0.00309	
LOCAL TRANSMISSION	0.04241	(I)	0.04241	(I)	0.04241	(I)	0.04241	(I)
CPUC FEE	0.00069		0.00069		0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		0.00157		0.00157		0.00157	
CEE INCENTIVE	0.00013		0.00013		0.00013		0.00013	
SMARTMETER™ PROJECT – GAS	0.00768		0.00768		0.00768		0.00768	
WGSP – TRANSPORTATION	0.00189		0.00189		0.00189		0.00189	
CORE IMPLEMENTATION PLAN – LT	0.02024		0.02024		0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327		0.00327		0.00327		0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033		0.00033		0.00033		0.00033	
TOTAL RATE	0.31629	(R)	0.14837	(I)	0.38898	(R)	0.18247	(I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

GAS PRELIMINARY STATEMENT PART B
DEFAULT TARIFF RATE COMPONENTS

Sheet 10

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM)* (Cont'd.) CORE p. 10

	G-CT (CORE TRANSPORT)			
	G-NGV1		G-NGV2	
CORE FIXED COST ACCOUNT—DISTRIBUTION COST SUBACCOUNT (1) **	0.04817	(I)	1.30268	(I)
CORE FIXED COST ACCOUNT—CORE COST SUBACCOUNT	0.00658	(I)	0.00658	(I)
CFCA - ARB AB 32 COI	0.00309		0.00309	
LOCAL TRANSMISSION	0.04241	(I)	0.04241	(I)
CPUC FEE	0.00069		0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157		0.00157	
CEE INCENTIVE	0.00002		0.00002	
NGV BALANCING ACCOUNT	0.00000		0.00000	
SMARTMETER™ PROJECT—GAS	0.01570		0.01570	
CORE IMPLEMENTATION PLAN – LT	0.02024		0.02024	
CORE IMPLEMENTATION PLAN – BB	0.00327		0.00327	
CORE IMPLEMENTATION PLAN - STORAGE	0.00033		0.00033	
TOTAL RATE	0.14207	(I)	1.39658	(I)

* All tariff rate components on this sheet include an allowance for franchise fees and uncollectible accounts expense (F&U).

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

(Continued)

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

CORE (Cont'd.)

(1) The CFCA-Distribution Cost subaccount includes GRC base revenue, as defined in Preliminary Statement, Part C, and the amortization of prior balances in the CFCA. All revenue collected through Customer Charges will be booked to the CFCA-Distribution Cost subaccount. (See rate schedules for Customer Charge.) (T) (T)

(2) The Core Procurement Charge includes the gas supply portfolio cost, the component that amortizes the balance in the Core Subaccount of the Purchased Gas Account (PGA), carrying cost on cycled storage gas, and the allowance for F&U. (T)

Customers taking service on Schedules G-NR1, G-NR2 or G-NGV1 that have executed a Request for Reclassification from Noncore Service to Core Service (Form 79-983) will pay the Procurement Charge specified in Schedule G-CPX – Crossover Gas Procurement Service to Core End-Use Customers, for any of the first twelve (12) regular monthly billing periods that they are taking core procurement service from PG&E. After the twelfth regular monthly billing period, such Customers will pay the Procurement Charge specified on their otherwise-applicable schedule. Any procurement revenue collected under Schedule G-CPX in excess of the otherwise-applicable rate will be recorded the same as the Core Procurement Charge.

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

(Continued)

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	$0.00701	$0.00701	$0.00701	$0.00701	$0.00701	
NCA – INTERIM RELIEF AND DISTRIBUTION	-$0.00015	-$0.00246	-$0.00246	-$0.00246	-$0.00246	
CPUC FEE	$0.00069	$0.00069	$0.00069	$0.00069	$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157	$0.00157	$0.00157	$0.00157	$0.00157	
CEE INCENTIVE	$0.00000	$0.00009	$0.00009	$0.00009	$0.00009	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	$0.01990	$0.01990	$0.01990	$0.01990	$0.01990	(T)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00642	$0.13816	$0.08809	$0.07786	$0.06986	
NCA- ARBAB32 COI	$0.00309	$0.00309	$0.00309	$0.00309	$0.00309	
NONCORE IMPLEMENTATION PLAN- LT	$0.00946	$0.00946	$0.00946	$0.00946	$0.00946	
NONCORE IMPLEMENTATION PLAN- BB	$0.00274	$0.00274	$0.00274	$0.00274	$0.00274	
NONCORE IMPLEMENTATION PLAN- Storage	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	
TOTAL RATE	0.05087	0.18039	0.13032	0.12009	0.11209	

* 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

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

	G-NT BACKBONE	G-NT—DISTRIBUTION WINTER				
THERMS:		0-20,833	20,834-49,999	50,000-166,666	166,667-249,999***	
NCA – NONCORE	$0.00701	$0.00701	$0.00701	$0.00701	$0.00701	
NCA – INTERIM RELIEF AND DISTRIBUTION	0.00000	-$0.00246	-$0.00246	-$0.00246	-$0.00246	
CPUC FEE	0.00069	$0.00069	$0.00069	$0.00069	$0.00069	
CSI- SOLAR THERMAL PROGRAM	0.00157	$0.00157	$0.00157	$0.00157	$0.00157	
CEEINCENTIVE	0.00000	$0.00009	$0.00009	$0.00009	$0.00009	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	0.00068	$0.01990	$0.01990	$0.01990	$0.01990	(T)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	0.00000	$0.18650	$0.11891	$0.10510	$0.09430	
NCA - ARB AB32 COI	0.00309	$0.00309	$0.00309	$0.00309	$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	0.00000	$0.00946	$0.00946	$0.00946	$0.00946	
NONCORE IMPLEMENTATION PLAN - BB	0.00274	$0.00274	$0.00274	$0.00274	$0.00274	
NONCORE IMPLEMENTATION PLAN - Storage	0.00014	$0.00014	$0.00014	$0.00014	$0.00014	
TOTAL RATE	0.01592	0.22873	0.16114	0.14733	0.13653	

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* 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

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

	G-EG (2)**	G-EG BACKBONE	
			(T)
NCA – NONCORE	$0.00701	$0.00701	
NCA – INTERIM RELIEF AND DISTRIBUTION	-$0.00005	-$0.00005	
CPUC FEE	$0.00003	$0.00003	
CSI- SOLAR THERMAL PROGRAM	$0.00000	$0.00000	
CEE INCENTIVE	$0.00000	$0.00000	
LOCAL TRANSMISSION OR SURCHARGE (AT RISK) (3)	$0.01990	$0.00068	(T)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00202	$0.00202	
NCA - ARB AB32 COI	$0.00309	$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946	$0.00000	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274	$0.00274	
NONCORE IMPLEMENTATION PLAN - Storage	$0.00014	$0.00014	
TOTAL RATE	0.04434	0.01566	

* 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	$0.00620	(R)	$0.00620	(R)	$0.00620	(R)	$0.00620	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$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)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.00000		$0.00000		$0.00000	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	0.03844	(R)	0.03844	(R)	0.03844	(R)	0.03844	(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

Sheet 16

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

	G-WSL					
	West Coast Mather-T		West Coast Mather-D		West Coast Castle-D	
NCA – NONCORE	$0.00620	(R)	$0.00620	(R)	$0.00620	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00198		-$0.00238	
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)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.13596		$0.10356	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014	
TOTAL RATE	0.03844	(R)	0.17242	(R)	0.13962	(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

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	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246		-$0.00246		-$0.00246		-$0.00246	
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157		$0.00157		$0.00157		$0.00157		$0.00157	
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.13816		$0.08809		$0.07786		$0.06986	
NCA - ARB AB32 COI	$0.00309		$0.00309		$0.00309		$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00946		$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	0.04460	(R)	0.18039	(R)	0.13032	(R)	0.12009	(R)	0.11209	(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.)*

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	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)	$0.00701	(R)
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000		-$0.00246		-$0.00246		-$0.00246		-$0.00246	
CPUC FEE	$0.00069		$0.00069		$0.00069		$0.00069		$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00157		$0.00157		$0.00157		$0.00157		$0.00157	
CEE INCENTIVE	$0.00000		$0.00009		$0.00009		$0.00009		$0.00009	
LNGV BALANCING ACCOUNT										
LOCAL TRANSMISSION (AT RISK)	$0.00068		$0.01990	(I)	$0.01990	(I)	$0.01990	(I)	$0.01990	(I)
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000		$0.18650	(R)	$0.11891		$0.10510		$0.09430	
NCA - ARB AB32 COI	$0.00309		$0.00309		$0.00309		$0.00309		$0.00309	
NONCORE IMPLEMENTATION PLAN – LT	$0.00000		$0.00946		$0.00946		$0.00946		$0.00946	
NONCORE IMPLEMENTATION PLAN – BB	$0.00274		$0.00274		$0.00274		$0.00274		$0.00274	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00014		$0.00014		$0.00014		$0.00014		$0.00014	
TOTAL RATE	0.01592	(R)	0.22873	(R)	0.16114	(R)	0.14733	(R)	0.13653	(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 19

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

	G-LNG (1)*	
NCA – NONCORE	$0.00000	
NCA – INTERIM RELIEF AND DISTRIBUTION	$0.00000	
CPUC Fee	$0.00069	
CSI- SOLAR THERMAL PROGRAM	$0.00000	
CEE	$0.00000	
LNGV BALANCING ACCOUNT	$0.18238	(R)
LOCAL TRANSMISSION (AT RISK)	$0.00000	
NONCORE DISTRIBUTION FIXED COST ACCOUNT	$0.00000	
NONCORE IMPLEMENTATION PLAN – LT	$0.00000	
NONCORE IMPLEMENTATION PLAN – BB	$0.00000	
NONCORE IMPLEMENTATION PLAN – Storage	$0.00000	
TOTAL RATE	0.18307	(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	$0.23518	(R)	0 – 5.0	$0.27048
			5.1 to 16.0	$0.52106
			16.1 to 41.0	$0.95482
			41.1 to 123.0	$1.66489
			123.1 & Up	$2.14936
Schedule G-NR2	$0.09911		All Usage Levels	$4.95518
Schedule G-NGV1	$0.06389		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	$0.09911	0 to 5,000	$1.93578
Local Transmission	$0.00641	5,001 to 10,000	$5.76658
Backbone	$0.00000	10,001 to 50,000	$10.73293
		50,001 to 200,000	$14.08570
Schedule G-EG		200,001 to 1,000,000	$20.43715
Distribution	$0.00201	1,000,001 and above	$173.35956
Local Transmission	$0.00201		
Backbone	$0.00201		
Schedule G-NGV4			
Distribution	$0.09911		
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 B
DEFAULT TARIFF RATE COMPONENTS

Sheet 21

B. DEFAULT TARIFF RATE COMPONENTS ($/THERM) (Cont'd.) PPP p. 1

SCHEDULE G-PPPS – GAS PUBLIC PURPOSE PROGRAM SURCHARGE

	PPP-EE	PPP-LIEE	PPP-RDD/ADMIN	PPP-CARE	Total-PPP
RESIDENTIAL – NONCARE (G-1, GM, GS, GT)	$0.02015 (R)	$0.02128 (R)	$0.00227 (R)	$0.02181 (R)	$0.06551 (R)
RESIDENTIAL – CARE (GL-1, GML, GSL, GTL)	$0.02015 (R)	$0.02128 (R)	$0.00227 (R)	$0.00000	$0.04370 (R)
SMALL COMMERCIAL – NONCARE (G-NR1)	$0.00715 (R)	$0.00755 (R)	$0.00227 (R)	$0.02181 (R)	$0.03878 (R)
SMALL COMMERCIAL – CARE (G-NR1)	$0.00715 (R)	$0.00755 (R)	$0.00227 (R)	$0.00000	$0.01697 (R)
LARGE COMMERCIAL – NONCARE (G-NR2)	$0.02300 (R)	$0.02429 (R)	$0.00227 (R)	$0.02181 (R)	$0.07137 (R)
LARGE COMMERCIAL – CARE (G-NR2)	$0.02300 (R)	$0.02429 (R)	$0.00227 (R)	$0.00000	$0.04956 (R)
NATURAL GAS VEHICLE (G-NGV1/G-NGV2)	$0.00000	$0.00000	$0.00227 (R)	$0.02181 (R)	$0.02408 (R)
INDUSTRIAL – DISTRIBUTION (G-NT-D)	$0.00564 (R)	$0.00596 (R)	$0.00227 (R)	$0.02181 (R)	$0.03568 (R)
INDUSTRIAL – TRANSMISSION/ BACKBONE (G-NT-T, G-NT-B)	$0.00283 (R)	$0.00299 (R)	$0.00227 (R)	$0.02181 (R)	$0.02990 (R)
NATURAL GAS VEHICLE (G-NGV4 Dist/Trans)	$0.00000	$0.00000	$0.00227 (R)	$0.02181 (R)	$0.02408 (R)
LIQUID NATURAL GAS (G-LNG)	$0.00000	$0.00000	$0.00227 (R)	$0.02181 (R)	$0.02408 (R)

(Continued)

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

NONCORE (Cont'd.)

(1) All transportation revenue collected through this rate, less the amount for CPUC fee, will be booked to the Natural Gas Vehicle Balancing Account (NGVBA).

(D)

(2) The CPUC fee applies to all gas delivery service under Schedule G-EG, with the exception of interdepartmental sales and sales to electric public utilities. (See Preliminary Statement Part O.) (T)

(3) The Surcharge only applies to Backbone Level End-Use Service for Schedules G-EG and G-NT, and recovers a portion of the negotiated monthly bill credits, as approved in Decision 11-04-031. There is no Local Transmission rate component for these customers. (T)

EXHIBIT B

Statement of Proposed Changes

PACIFIC GAS AND ELECTRIC COMPANY
Implementation Plan Rate Impacts
Illustrative Class Average End-User Rates
($ per Therm)

Line No.	Customer Class	Present April 2013 Rates(a) ($/Th)	Change in Gas Pipeline Safety Rates	Proposed 2013 Rates(a) With Implementation Plan Update Costs ($/Th)	Percentage Change
1	Core Retail - Bundled(b)				
2	Residential (Non-Care)(c)(e)	$1.213	-$0.002	$1.211	-0.13%
3	Commercial, Small (Non-Care)(e)	$0.929	-$0.002	$0.928	-0.16%
4	Commercial, Large	$0.722	-$0.002	$0.721	-0.21%
5	NGV Service - Compression on Customer Premises	$0.634	-$0.002	$0.633	-0.24%
6	Compressed NGV Service	$1.887	-$0.002	$1.886	-0.08%
7	Core Retail - Transportation Only(d)				
8	Residential (Non-Care)	$0.689	-$0.002	$0.688	-0.22%
9	Commercial, Small (Non-Care)	$0.425	-$0.002	$0.424	-0.36%
10	Commercial, Large	$0.257	-$0.002	$0.255	-0.60%
11	Noncore Retail - Transportation Only(d)				
12	Industrial Distribution	$0.185	-$0.001	$0.183	-0.71%
13	Industrial Transmission	$0.083	-$0.001	$0.081	-1.60%
14	Industrial Backbone	$0.047	-$0.001	$0.046	-3.02%
15	Electric Generation - Distribution/Transmission	$0.045	-$0.001	$0.044	-2.91%
16	Electric Generation - Backbone	$0.016	-$0.001	$0.014	-9.01%
17	Noncore NGV Service - Distribution	$0.173	-$0.001	$0.172	-0.76%
18	Noncore NGV Service - Transmission	$0.070	-$0.001	$0.069	-1.87%
19	Wholesale - Transportation Only(d)				
20	Alpine Natural Gas	$0.044	-$0.001	$0.043	-2.98%
21	Coalinga	$0.045	-$0.001	$0.044	-2.93%
22	Island Energy	$0.063	-$0.001	$0.062	-2.08%
23	Palo Alto	$0.040	-$0.001	$0.039	-3.29%
24	West Coast Gas - Castle(f)	$0.155	-$0.001	$0.153	-0.85%
25	West Coast Gas - Mather Transmission	$0.182	-$0.001	$0.180	-0.73%
26	West Coast Gas - Mather Distribution(f)	$0.048	-$0.001	$0.046	-2.77%

Illustrative Class Average End-User Rates
With Proxy Noncore Procurement Rates (Equal to Core Large Commercial Procurement Rate)
($ per Therm)

Line No.	Customer Class	Present April 2013 Rates(a) ($/Th)	Change in Gas Pipeline Safety Rates	Proposed 2013 Rates(a) With Implementation Plan Update Costs ($/Th)	Percentage Change
27	Noncore Retail - Transportation Only(d)				
28	Industrial Distribution	$0.650	-$0.001	$0.649	-0.20%
29	Industrial Transmission	$0.548	-$0.001	$0.547	-0.24%
30	Industrial Backbone	$0.513	-$0.001	$0.512	-0.28%
31	Electric Generation - Distribution/Transmission	$0.511	-$0.001	$0.510	-0.26%
32	Electric Generation - Backbone	$0.482	-$0.001	$0.480	-0.30%
33	Noncore NGV Service - Distribution	$0.639	-$0.001	$0.637	-0.21%
34	Noncore NGV Service - Transmission	$0.536	-$0.001	$0.535	-0.25%
35	Wholesale - Transportation Only(d)				
36	Alpine Natural Gas	$0.510	-$0.001	$0.509	-0.26%
37	Coalinga	$0.511	-$0.001	$0.509	-0.26%
38	Island Energy	$0.529	-$0.001	$0.528	-0.25%
39	Palo Alto	$0.506	-$0.001	$0.505	-0.26%
40	West Coast Gas - Castle(f)	$0.620	-$0.001	$0.619	-0.21%
41	West Coast Gas - Mather Transmission	$0.647	-$0.001	$0.646	-0.21%
42	West Coast Gas - Mather Distribution(f)	$0.513	-$0.001	$0.512	-0.26%

(a) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage. Rates are rounded to three decimal places for ease of viewing. Percentage rate changes are calculated on a 5 digit basis.

(b) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.372 per therm; (ii) a transportation componei that recovers Customer Class Charge (CCC), customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a G PPP surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), Low Income Energy Efficiency (LIEE), Customer Energy Efficiency (CEE), Research Development and Demonstration program and State Board of Equalization (BOE)/CPUC Administrative costs. Actual procurement rates change monthly.

(c) CARE customers receive a 20 percent discount on transportation and procurement and are exempt from paying CARE surcharges.

(d) Transportation Only rates include: (i) a transportation component that recovers CCC, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a G-PPP surcharge that recovers the cos of low income CARE, LIEE, CEE, Research Development and Demonstration program and State BOE/CPUC Administrative costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(e) Residential and Small Commercial Classes are 10 percent averaged.

(f) West Coast Gas is allocated 80 percent of its full distribution cost as of January 1, 2013.

EXHIBIT C

Results of Operation at Proposed Rates

Pacific Gas and Electric Company

Statement of Proposed Changes and Results of Operation

Results of Operations at Proposed Rates

Pipeline Safety Enhancement Plan - Update

(Thousands of Dollars)

Ln.No.		2012 (A)	2013 (B)	2014 (C)	Ln.No.
1	**Operating Revenue:**	86,653	104,541	139,137	1
2	Disallowance for pre-12/20/12 revenues	(83,804)	-	-	2
3	Total Operating Revenue	2,849	104,541	139,137	3
		-	-	-	
	Operating Expenses:	0	0	0	
4	Energy/Fuel Expenses	-	-	-	4
5	Production	-	-	-	5
6	Storage	369	957	105	6
7	Transmission	78,011	68,767	61,441	7
8	IT	0	0	0	8
9	Customer Accounts	-	-	-	9
10	Customer Services	-	-	-	10
11	Other Adjustments	-	-	-	11
12	Uncollectibles	269	325	432	12
13	Franchise Requirements	843	1,017	1,354	13
14	Subtotal Expenses	79,492	71,066	63,332	14
	Taxes:	-	-	-	
15	Property	82	1,035	4,039	15
16	Payroll	-	-	-	16
17	Business and Other Taxes	-	-	-	17
18	State Corporation Franchise	(460)	(982)	(201)	18
19	Federal Income	280	4,257	14,386	19
20	Subtotal Taxes	(98)	4,310	18,225	20
21	**Depreciation**	1,451	5,683	10,970	21
22	**Decommissioning**	-	-	-	22
23	**Total Operating Expenses**	80,846	81,058	92,526	23
		-	-	-	
24	**Net for Return**	5,807	23,483	46,610	24
		-	-	-	
25	**Weighted Average Rate Base**	66,061	291,353	578,294	25
26	**Rate of Return: On Rate Base**	8.79%	8.06%	8.06%	26
27	**On Equity**	11.35%	10.40%	10.40%	27

EXHIBIT D

Service of Cities and Counties

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Department of General Services
Office of Buildings & Grounds
505 Van Ness Avenue, Room 2012
San Francisco, CA 94102

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda
Alpine
Amador
Butte
Calaveras
Colusa
Contra Costa
El Dorado
Fresno
Glenn
Humboldt
Kern
Kings
Lake
Lassen
Madera
Marin
Mariposa
Mendocino
Merced
Modoc
Monterey
Napa
Nevada
Placer
Plumas
Sacramento
San Benito
San Bernardino
San Francisco
San Joaquin
San Luis Obispo
San Mateo
Santa Barbara
Santa Clara
Santa Cruz
Shasta
Sierra
Siskiyou
Solano
Sonoma
Stanislaus
Sutter
Tehama
Trinity
Tulare
Tuolumne
Yolo
Yuba

Municipal Corporations

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley
Millbrae
Milpitas
Modesto
Monte Sereno

Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City