**DATA REQUEST RESPONSES REFERENCED**

**IN PREPARED TESTIMONY OF DAVID BERGER AND THOMAS J. LONG**

**Pacific Gas and Electric Company**
**2015 Gas Transmission and Storage Rate Case**
**A.13-12-012**

**SUBMITTED ON BEHALF OF**
**THE UTILITY REFORM NETWORK**

**THE UTILITY REFORM NETWORK**
785 Market Street, Suite 1400
San Francisco, CA 94103
Telephone: (415) 929-8876 x303
E-mail: TLong@turn.org

August 11, 2014

**PACIFIC GAS AND ELECTRIC COMPANY**
**Gas Transmission and Storage Rate Case 2015**
**Application 13-12-012**
**Data Response**

| PG&E Data Request No.: | TURN_008-07 | | |
|---|---|---|---|
| PG&E File Name: | GTS-RateCase2015_DR_TURN_008-Q07 | | |
| Request Date: | March 3, 2014 | Requester DR No.: | TURN-8 |
| Date Sent: | March 17, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long |

**QUESTION 7**

Regarding Annual PHMSA Reports, required by 49 CFR Part 191: Please provide PG&E's annual reports to PHMSA for years 2010, 2011 and 2012.

**ANSWER 7**

*Attachments to this response have been marked CONFIDENTIAL and are submitted pursuant to the Non-Disclosure Agreement because they include employee names below the Director level.*

PG&E is providing the Pipeline and Hazardous Materials Safety Administration (PHMSA) annual reports for years 2010, 2011, and 2012 via UPS Next Day Air. Due to the size of the files, the reports are being provided in CD format as follows:

- 2010 Gas Transmission Department of Transportation Annual Report to PHMSA
  GTS-RateCase2015_DR_TURN_008-Q07Atch01CONF (PG&E)
  GTS-RateCase2015_DR_TURN_008-Q07Atch02CONF (StanPac)

- 2011 Gas Transmission Department of Transportation Annual Report to PHMSA
  GTS-RateCase2015_DR_TURN_008-Q07Atch03CONF (PG&E)
  GTS-RateCase2015_DR_TURN_008-Q07Atch04CONF (StanPac)

- 2012 Gas Transmission Department of Transportation Annual Report to PHMSA
  GTS-RateCase2015_DR_TURN_008-Q07Atch05CONF (PG&E)
  GTS-RateCase2015_DR_TURN_008-Q07Atch06CONF (StanPac)

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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OMB No. 2137-0522
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| U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration | **ANNUAL REPORT FOR CALENDAR YEAR 2010 NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS** | **Report Submission Type** **ORIGINAL** |
|---|---|---|

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 22 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** Please read the separate instructions for completing this form before you begin.

| **PART A - OPERATOR INFORMATION** | DOT USE ONLY | **20110772 - 22836** |
|---|---|---|

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

**15007**

2. NAME OF COMPANY OR ESTABLISHMENT:

**PACIFIC GAS & ELECTRIC CO**

IF SUBSIDIARY, NAME OF PARENT:

**PG&E Corporation**

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

Name: [redacted]

Title: **Sr. Program Manager**

Email Address: [redacted]

Telephone Number: [redacted]

4. HEADQUARTERS ADDRESS:

**PG&E Corporation**
Company Name

**77 Beale Street, San Francisco**
Street Address

State: **CA** Zip Code: **94105**

**(800) 743-5000**
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

**Natural Gas**

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O).

Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8.

7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

INTERstate pipeline - List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: etc.

INTRAstate pipeline - List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: **CALIFORNIA** etc.

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8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☑ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply*. Complete all remaining PARTS of this form as applicable

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable)

- ☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
- ☐ Divestiture of pipelines and/or pipeline facilities
- ☐ New construction or new installation of pipelines and/or pipeline facilities
- ☐ Conversion to service, change in commodity transported, or c change in MAOP (maximum allowable operating pressure)
- ☐ Abandonment of existing pipelines and/or pipeline facilities
- ☐ Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
- ☐ Change in OPID

Other – Describe: ,

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***For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.***

| PART B – TRANSMISSION PIPELINE HCA MILES | |
|---|---|
| | Number of HCA Miles in the IMP Program |
| **Onshore** | 1031 |
| **Offshore** | 0 |
| Total Miles | 1031 |

| PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems) | Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems. | |
|---|---|---|
| | **Onshore** | **Offshore** |
| Natural Gas | 770267 | |
| Propane Gas | 0 | |
| Synthetic Gas | 0 | |
| Hydrogen Gas | 0 | |
| Other Gas - Name: | 0 | |

| PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION | | | | | |
|---|---|---|---|---|---|
| | Cathodically protected | | Cathodically unprotected | | Total Miles |
| | Bare | Coated | Bare | Coated | |
| **Transmission** | | | | | |
| Onshore | 8.7 | 5717.5 | 0 | 0 | *5726.2* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Transmission | *8.7* | *5717.5* | *0* | *0* | *5726.2* |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 4.5 | 0 | 0 | *4.5* |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Gathering | *0* | *4.5* | *0* | *0* | *4.5* |
| **Total Miles** | *8.7* | *5722* | *0* | *0* | *5730.7* |

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| PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION | | | | | |
|---|---|---|---|---|---|
| | Cast Iron Pipe | Wrought Iron Pipe | Plastic Pipe | Other Pipe | Total Miles |
| **Transmission** | | | | | |
| Onshore | 0 | .8 | 0 | 0 | *.8* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Transmission | *0* | *.8* | *0* | *0* | *.8* |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | *0* |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Gathering | *0* | *0* | *0* | *0* | *0* |
| **Total Miles** | *0* | *.8* | *0* | *0* | *.8* |

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***For the designated Commodity Group, complete PARTs F and G one time for all INTERstate pipelines and/or pipeline facilities included within this OPID and multiple times as needed for the designated Commodity Group for each State in which INTRAstate pipelines and/or pipeline facilities included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.***

**PARTs F and G**

**The data reported in these PARTs F and G applies to:** *(select only one)*

**Interstate pipelines/pipeline facilities**

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## PARTs F and G

**The data reported in these PARTs F and G applies to:** *(select only one)*

**Intrastate pipelines/pipeline facilities in the State** *(complete for each State)*

| PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION<br>Intrastate pipelines/pipeline facilities in the State - **CALIFORNIA** | |
|---|---|
| **1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS** | |
| a. Corrosion or metal loss tools | 38 |
| b. Dent or deformation tools | 71.2 |
| c. Crack or long seam defect detection tools | 0 |
| d. Any other internal inspection tools | 0 |
| e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d ) | *109.2* |
| **2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS** | |
| a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation. | 7 |
| b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 6 |
| c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of: | 3 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 2 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 1 |
| **3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING** | |
| a. Total mileage inspected by pressure testing in calendar year. | 0 |
| b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| **4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)** | |
| a. Total mileage inspected by each DA method in calendar year. | *168.2* |
| 1. ECDA | 168.2 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | *1* |
| 1. ECDA | 1 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | *1* |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 1 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES** | |
| a. Total mileage inspected by inspection techniques other than those listed above in calendar year. | 0 |

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| | |
|---|---|
| b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | *0* |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR** | |
| a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a) | *277.4* |
| b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b) | *7* |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4) | *4* |

| | |
|---|---|
| **PART G– MILES OF BASELINE ASSESSMENTS AND IN CALENDAR YEAR (HCA Segment miles ONLY)** | |
| a. Baseline assessment miles completed during the calendar year. | 139.7 |
| b. Reassessment miles completed during the calendar year. | 47.2 |
| c. Total assessment and reassessment miles completed during the calendar year. | *186.9* |

***For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.***

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**PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Onshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | 384.6 | 442.7 | 597.5 | 404.8 | 762.5 | 0.1 | 373.6 | 59.9 | 222.8 |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | 65.4 | 303.1 | 139.5 | 0 | 107.9 | 19 | 1023.7 | 518.6 | 0 |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | 0 | 301.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; | | | | | | | |
| | 0 | | | | | | | | |
| 5727 | Total Miles of Onshore Pipe – Transmission | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | | | | | | | | | |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ; | | | | | | | |
| | | | | | | | | | |
| | Total Miles of Offshore Pipe – Transmission | | | | | | | | |

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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**PART I - MILES OF GATHERING PIPE BY NOMINAL PIPE SIZE (NPS)**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Onshore Type A** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" | |
| | 4.1 | 0.4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" | |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; | | | | | | | | | |
| 4.5 | Total Miles of Onshore Type A Pipe - Gathering | | | | | | | | | |
| **Onshore Type B** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" | |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" | |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; | | | | | | | | | |
| 0 | Total Miles of Onshore Type B Pipe – Gathering | | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" | |
| | | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" | |
| | | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
| | | | | | | | | | | |
| | Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ; | | | | | | | | | |
| | Total Miles of Offshore Pipe - Gathering | | | | | | | | | |

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**PART J – MILES OF PIPE BY DECADE INSTALLED**

Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| Decade Pipe Installed | Pre-40 or Unknown | 1940 - 1949 | 1950 - 1959 | 1960 - 1969 | 1970 - 1979 | 1980 - 1989 |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | 300.3 | 412.9 | 1957.3 | 1170.6 | 341.5 | 537.3 |
| Offshore | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal Transmission | 300.3 | 412.9 | 1957.3 | 1170.6 | 341.5 | 537.3 |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | 1.7 | .8 |
| Onshore Type B | 0 | 0 | 0 | 0 | 0 | 0 |
| Offshore | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 1.7 | .8 |
| **Total Miles** | 300.3 | 412.9 | 1957.3 | 1170.6 | 343.2 | 538.1 |
| **Decade Pipe Installed** | 1990 - 1999 | 2000 - 2009 | 2010 - 2019 | | | Total Miles |
| **Transmission** | | | | | | |
| Onshore | 782.7 | 208.7 | 15.7 | | | 5727 |
| Offshore | 0 | 0 | 0 | | | 0 |
| Subtotal Transmission | 782.7 | 208.7 | 15.7 | | | 5727 |
| **Gathering** | | | | | | |
| Onshore Type A | 2 | 0 | 0 | | | 4.5 |
| Onshore Type B | 0 | 0 | 0 | | | 0 |
| Offshore | 0 | 0 | 0 | | | 0 |
| Subtotal Gathering | 2 | 0 | 0 | | | 4.5 |
| **Total Miles** | 784.7 | 208.7 | 15.7 | | | 5731.5 |

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**PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| ONSHORE | CLASS LOCATION | | | | Total Miles |
|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | |
| **Less than 20% SMYS** | 301.6 | 52.2 | 351.7 | 1 | 706.5 |
| **Greater than or equal to 20% SMYS but less than 30% SMYS** | 411.7 | 106.4 | 619.1 | .1 | 1137.3 |
| **Greater than or equal to 30% SMYS but less than or equal to 40% SMYS** | 336.3 | 75.9 | 358.5 | .4 | 771.1 |
| **Greater than 40% SMYS but less than or equal to 50% SMYS** | 603.6 | 87.2 | 248.2 | 0 | 939 |
| **Greater than 50% SMYS but less than or equal to 60% SMYS** | 536 | 53.7 | 67.1 | 0 | 656.8 |
| **Greater than 60% SMYS but less than or equal to 72% SMYS** | 1476.7 | 33.9 | 4.9 | 0 | 1515.5 |
| **Greater than 72% SMYS but less than or equal to 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Unknown percent of SMYS** | 0 | 0 | 0 | 0 | 0 |
| **All Non-Steel pipe** | 0 | 0 | .8 | 0 | .8 |
| Onshore Totals | 3665.9 | 409.3 | 1650.3 | 1.5 | 5727 |
| **OFFSHORE** | Class I | | | | |
| **Less than or equal to 50% SMYS** | 0 | | | | |
| **Greater than 50% SMYS but less than or equal to 72% SMYS** | 0 | | | | |
| Offshore Total | 0 | | | | 0 |
| **Total Miles** | 3665.9 | | | | 5727 |

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**PART L - MILES OF PIPE BY CLASS LOCATION**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| | Class Location | | | | Total Class Location Miles | HCA Miles in the IMP Program |
|---|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | | |
| **Transmission** | | | | | | |
| Onshore | 3665.9 | 409.4 | 1650.2 | 1.5 | *5727* | *1031* |
| Offshore | 0 | 0 | 0 | 0 | *0* | *0* |
| Subtotal Transmission | 3665.9 | 409.4 | 1650.2 | 1.5 | 5727 | *1031* |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 4.5 | 0 | 0 | *4.5* | |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* | |
| Offshore | 0 | 0 | 0 | 0 | *0* | |
| Subtotal Gathering | 0 | 4.5 | 0 | 0 | 4.5 | |
| **Total Miles** | 3665.9 | 413.9 | 1650.2 | 1.5 | *5731.5* | *1031* |

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**PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

**PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR**

| Cause | Transmission Incidents, Leaks, and Failures | | | | | | Gathering Leaks | | |
|---|---|---|---|---|---|---|---|---|---|
| | Incidents in HCA Segments | Leaks | | | | Failures in HCA Segments | Onshore Leaks | | Offshore Leaks |
| | | Onshore Leaks | | Offshore Leaks | | | | | |
| | | HCA | Non-HCA | HCA | Non-HCA | | Type A | Type B | |
| External Corrosion | 0 | 2 | 7 | 0 | 0 | 0 | 0 | 0 | 0 |
| Internal Corrosion | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 |
| Stress Corrosion Cracking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Manufacturing | 0 | 2 | 3 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction | 0 | 8 | 11 | 0 | 0 | 0 | 0 | 0 | 0 |
| Equipment | 0 | 2 | 37 | 0 | 0 | 9 | 0 | 0 | 0 |
| Incorrect Operations | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 |
| Third Party Damage/Mechanical Damage | | | | | | | | | |
| Excavation Damage | 0 | 0 | 3 | 0 | 0 | 1 | 0 | 0 | 0 |
| Previous Damage (due to Excavation Activity) | 0 | 0 | 1 | 0 | 0 | 4 | 0 | 0 | 0 |
| Vandalism (includes all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Weather Related/Other Outside Force | | | | | | | | | |
| Natural Force Damage (all) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Outside Force Damage (excluding Vandalism and all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 1 | 0 | 17 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | *1* | *14* | *81* | *0* | *0* | *17* | *0* | *0* | *0* |

**PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR**

| | | | |
|---|---|---|---|
| **Transmission** | 42 | **Gathering** | 0 |

**PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR**

| **Transmission** | | **Gathering** | |
|---|---|---|---|
| Onshore | 4 | Onshore Type A | 0 |
| | | Onshore Type B | 0 |
| OCS | 0 | OCS | 0 |
| Subtotal Transmission | *4* | Subtotal Gathering | *0* |
| Total | *4* | | |

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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***For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.***

**PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)**

[redacted]

Preparer's Name(type or print)

[redacted]

Telephone Number

**Sr. Program Manager**

Preparer's Title

Facsimile Number

[redacted]

Preparer's E-mail Address

**PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)**

**Nickolas Stavropoulos**

Senior Executive Officer's signature certifying he information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**(415) 973-2020**

Telephone Number

**Nickolas Stavropoulos**

Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**Executive Vice President of Gas Operations**

Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**N1SL@pge.com**

Senior Executive Officer's E-mail Address

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| U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration | **ANNUAL REPORT FOR CALENDAR YEAR 2010 NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS** | **Report Submission Type** **ORIGINAL** |
|---|---|---|

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 22 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** Please read the separate instructions for completing this form before you begin.

| **PART A - OPERATOR INFORMATION** | DOT USE ONLY | **20110628 - 22681** |
|---|---|---|

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

**18608**

2. NAME OF COMPANY OR ESTABLISHMENT:

**STANDARD PACIFIC GAS LINE INC**

IF SUBSIDIARY, NAME OF PARENT:

**PG&E Corporation**

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

Name: [redacted]

Title: **Sr. Program Manager**

Email Address: [redacted]

Telephone Number: [redacted]

4. HEADQUARTERS ADDRESS:

**PG&E Corporation**
Company Name

**375 N. WIGET LANE, SUITE 200**
Street Address

State: **CA** Zip Code: **94598**

[redacted]
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

**Natural Gas**

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O).

Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8.

7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

INTERstate pipeline - List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: etc.

INTRAstate pipeline - List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: **CALIFORNIA** etc.

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8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☑ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply*. Complete all remaining PARTS of this form as applicable

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable)

- ☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
- ☐ Divestiture of pipelines and/or pipeline facilities
- ☐ New construction or new installation of pipelines and/or pipeline facilities
- ☐ Conversion to service, change in commodity transported, or c change in MAOP (maximum allowable operating pressure)
- ☐ Abandonment of existing pipelines and/or pipeline facilities
- ☐ Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
- ☐ Change in OPID

Other – Describe: ,

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***For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.***

| PART B – TRANSMISSION PIPELINE HCA MILES | |
|---|---|
| | Number of HCA Miles in the IMP Program |
| **Onshore** | 28 |
| **Offshore** | 0 |
| Total Miles | 28 |

| PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems) | Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems. | |
|---|---|---|
| | **Onshore** | **Offshore** |
| Natural Gas | 44173 | |
| Propane Gas | 0 | |
| Synthetic Gas | 0 | |
| Hydrogen Gas | 0 | |
| Other Gas - Name: | 0 | |

| PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION | | | | | |
|---|---|---|---|---|---|
| | Cathodically protected | | Cathodically unprotected | | Total Miles |
| | Bare | Coated | Bare | Coated | |
| **Transmission** | | | | | |
| Onshore | 0 | 54.6 | 0 | 0 | 54.6 |
| Offshore | 0 | 0 | 0 | 0 | 0 |
| Subtotal Transmission | 0 | 54.6 | 0 | 0 | 54.6 |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | 0 |
| Onshore Type B | 0 | 0 | 0 | 0 | 0 |
| Offshore | 0 | 0 | 0 | 0 | 0 |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 0 |
| **Total Miles** | 0 | 54.6 | 0 | 0 | 54.6 |

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**PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION**

| | Cast Iron Pipe | Wrought Iron Pipe | Plastic Pipe | Other Pipe | Total Miles |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Onshore | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Transmission | *0* | *0* | *0* | *0* | *0* |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | *0* |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Gathering | *0* | *0* | *0* | *0* | *0* |
| **Total Miles** | *0* | *0* | *0* | *0* | *0* |

***For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.***

**PARTs F and G**

**The data reported in these PARTs F and G applies to:** *(select only one)*

**Interstate pipelines/pipeline facilities**

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## PARTs F and G

**The data reported in these PARTs F and G applies to:** *(select only one)*

**Intrastate pipelines/pipeline facilities in the State** *(complete for each State)*

| PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION<br>Intrastate pipelines/pipeline facilities in the State - **CALIFORNIA** | |
|---|---|
| **1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS** | |
| a. Corrosion or metal loss tools | 0 |
| b. Dent or deformation tools | 0 |
| c. Crack or long seam defect detection tools | 0 |
| d. Any other internal inspection tools | 0 |
| e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d ) | *0* |
| **2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS** | |
| a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation. | 0 |
| b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of: | 0 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING** | |
| a. Total mileage inspected by pressure testing in calendar year. | 0 |
| b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| **4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)** | |
| a. Total mileage inspected by each DA method in calendar year. | *4.56* |
| 1. ECDA | 4.56 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | *0* |
| 1. ECDA | 0 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | *0* |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES** | |
| a. Total mileage inspected by inspection techniques other than those listed above in calendar year. | 0 |

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| | |
|---|---|
| b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | *0* |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR** | |
| a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a) | *4.56* |
| b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b) | *0* |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4) | *0* |
| **PART G– MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)** | |
| a. Baseline assessment miles completed during the calendar year. | 4.56 |
| b. Reassessment miles completed during the calendar year. | 0 |
| c. Total assessment and reassessment miles completed during the calendar year. | *4.56* |

***For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.***

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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**PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Onshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | 0 | 0.6 | 0.4 | 3.1 | 6.6 | 0 | 4.8 | 0 | 0 |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | .7 | 26.9 | 9.6 | 0 | 1.9 | 0 | 0 | 0 | 0 |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; | | | | | | | |
| | 0 | | | | | | | | |
| 54.6 | Total Miles of Onshore Pipe – Transmission | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | | | | | | | | | |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ; | | | | | | | |
| | | | | | | | | | |
| | Total Miles of Offshore Pipe – Transmission | | | | | | | | |

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**PART J – MILES OF PIPE BY DECADE INSTALLED**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| Decade Pipe Installed | Pre-40 or Unknown | 1940 - 1949 | 1950 - 1959 | 1960 - 1969 | 1970 - 1979 | 1980 - 1989 |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | .1 | 13.9 | 4 | .7 | 14.8 | 6.2 |
| Offshore | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal Transmission | .1 | 13.9 | 4 | .7 | 14.8 | 6.2 |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | 0 | 0 |
| Onshore Type B | 0 | 0 | 0 | 0 | 0 | 0 |
| Offshore | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Miles** | .1 | 13.9 | 4 | .7 | 14.8 | 6.2 |

| Decade Pipe Installed | 1990 - 1999 | 2000 - 2009 | 2010 - 2019 | | | Total Miles |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | 14.7 | .2 | 0 | | | 54.6 |
| Offshore | 0 | 0 | 0 | | | 0 |
| Subtotal Transmission | 14.7 | .2 | 0 | | | 54.6 |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 0 | 0 | | | 0 |
| Onshore Type B | 0 | 0 | 0 | | | 0 |
| Offshore | 0 | 0 | 0 | | | 0 |
| Subtotal Gathering | 0 | 0 | 0 | | | 0 |
| **Total Miles** | 14.7 | .2 | 0 | | | 54.6 |

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**PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| ONSHORE | CLASS LOCATION | | | | Total Miles |
|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | |
| **Less than 20% SMYS** | .3 | 0 | .5 | 0 | .8 |
| **Greater than or equal to 20% SMYS but less than 30% SMYS** | 16.1 | 0 | 14.5 | 0 | 30.6 |
| **Greater than or equal to 30% SMYS but less than or equal to 40% SMYS** | 4.9 | 0 | 7.4 | 0 | 12.3 |
| **Greater than 40% SMYS but less than or equal to 50% SMYS** | .2 | 0 | 10.7 | 0 | 10.9 |
| **Greater than 50% SMYS but less than or equal to 60% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 60% SMYS but less than or equal to 72% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 72% SMYS but less than or equal to 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Unknown percent of SMYS** | 0 | 0 | 0 | 0 | 0 |
| **All Non-Steel pipe** | 0 | 0 | 0 | 0 | 0 |
| Onshore Totals | 21.5 | 0 | 33.1 | 0 | 54.6 |
| **OFFSHORE** | Class I | | | | |
| **Less than or equal to 50% SMYS** | 0 | | | | |
| **Greater than 50% SMYS but less than or equal to 72% SMYS** | 0 | | | | |
| Offshore Total | 0 | | | | 0 |
| **Total Miles** | 21.5 | | | | 54.6 |

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**PART L - MILES OF PIPE BY CLASS LOCATION**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

| | Class Location | | | | Total Class Location Miles | HCA Miles in the IMP Program |
|---|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | | |
| **Transmission** | | | | | | |
| Onshore | 21.5 | 0 | 33.1 | 0 | *54.6* | *28* |
| Offshore | 0 | 0 | 0 | 0 | *0* | *0* |
| Subtotal Transmission | 21.5 | 0 | 33.1 | 0 | 54.6 | *28* |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | *0* | |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* | |
| Offshore | 0 | 0 | 0 | 0 | *0* | |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 0 | |
| **Total Miles** | 21.5 | 0 | 33.1 | 0 | *54.6* | *28* |

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**PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS**
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

**PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR**

| Cause | Transmission Incidents, Leaks, and Failures | | | | | | Gathering Leaks | | |
|---|---|---|---|---|---|---|---|---|---|
| | Incidents in HCA Segments | Leaks | | | | Failures in HCA Segments | Onshore Leaks | | Offshore Leaks |
| | | Onshore Leaks | | Offshore Leaks | | | | | |
| | | HCA | Non-HCA | HCA | Non-HCA | | Type A | Type B | |
| External Corrosion | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Internal Corrosion | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Stress Corrosion Cracking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Manufacturing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Equipment | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Incorrect Operations | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Third Party Damage/Mechanical Damage | | | | | | | | | |
| Excavation Damage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Previous Damage (due to Excavation Activity) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vandalism (includes all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Weather Related/Other Outside Force | | | | | | | | | |
| Natural Force Damage (all) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Outside Force Damage (excluding Vandalism and all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* |

**PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR**

| | | | |
|---|---|---|---|
| **Transmission** | 0 | **Gathering** | 0 |

**PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR**

| **Transmission** | | **Gathering** | |
|---|---|---|---|
| Onshore | 0 | Onshore Type A | 0 |
| | | Onshore Type B | 0 |
| OCS | 0 | OCS | 0 |
| Subtotal Transmission | *0* | Subtotal Gathering | *0* |
| Total | *0* | | |

***For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.***

**PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)**

[redacted]
Preparer's Name(type or print)

[redacted]
Telephone Number

**Sr. Program Manager**
Preparer's Title

Facsimile Number

[redacted]
Preparer's E-mail Address

**PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)**

**Nickolas Stavropoulos**
Senior Executive Officer's signature certifying he information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**(415) 973-2020**
Telephone Number

**Nickolas Stavropoulos**
Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**Executive Vice President of Gas Operations**
Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**N1SL@pge.com**
Senior Executive Officer's E-mail Address

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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| U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration | **ANNUAL REPORT FOR CALENDAR YEAR 2011 NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS** | **Report Submission Type**<br><br>**INITIAL** |
|---|---|---|

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 22 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** Please read the separate instructions for completing this form before you begin.

| **PART A - OPERATOR INFORMATION** | DOT USE ONLY | **20120944 - 25538** |
|---|---|---|

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

**15007**

2. NAME OF COMPANY OR ESTABLISHMENT:

**PACIFIC GAS & ELECTRIC CO**

IF SUBSIDIARY, NAME OF PARENT:

**PG&E Corporation**

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

Name: [redacted]

Title: **Sr. Program Manager**

Email Address: [redacted]

Telephone Number: [redacted]

4. HEADQUARTERS ADDRESS:

**Pacific Gas & Electric Co.**
Company Name

**77 Beale Street, San Francisco**
Street Address

State: **CA** Zip Code: **94105**

**(800) 743-5000**
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

**Natural Gas**

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O).

Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8.

7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

INTERstate pipeline - List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: etc.

INTRAstate pipeline - List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: **CALIFORNIA** etc.

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☐ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply.* Complete all remaining PARTS of this form as applicable

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

☑ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for PARTs B, D, E, H, I, J, K, or L because of one or more of the following ***change(s) in pipelines and/or pipeline facilities and/or operations*** from those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable). *(Select all reasons for these changes from the following list)*

- ☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
- ☐ Divestiture of pipelines and/or pipeline facilities
- ☑ New construction or new installation of pipelines and/or pipeline facilities
- ☐ Conversion to service, change in commodity transported, or c change in MAOP (maximum allowable operating pressure)
- ☐ Abandonment of existing pipelines and/or pipeline facilities
- ☑ Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
- ☐ Change in OPID

Other – Describe: , false

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***For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.***

| PART B – TRANSMISSION PIPELINE HCA MILES | |
|---|---|
| | Number of HCA Miles in the IMP Program |
| **Onshore** | 1040 |
| **Offshore** | 0 |
| Total Miles | 1040 |

| PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems) | Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems. | |
|---|---|---|
| | **Onshore** | **Offshore** |
| Natural Gas | 744415 | |
| Propane Gas | 0 | |
| Synthetic Gas | 0 | |
| Hydrogen Gas | 0 | |
| Other Gas - Name: N | 0 | |

| PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION | | | | | |
|---|---|---|---|---|---|
| | Cathodically protected | | Cathodically unprotected | | Total Miles |
| | Bare | Coated | Bare | Coated | |
| **Transmission** | | | | | |
| Onshore | 8.7 | 5734.3 | 0 | 0 | *5743* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Transmission | *8.7* | *5734.3* | *0* | *0* | *5743* |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 4.5 | 0 | 0 | *4.5* |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Gathering | *0* | *4.5* | *0* | *0* | *4.5* |
| **Total Miles** | *8.7* | *5738.8* | *0* | *0* | *5747.5* |

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**PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION**

| | Cast Iron Pipe | Wrought Iron Pipe | Plastic Pipe | Other Pipe | Total Miles |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Onshore | 0 | .8 | 0 | 0 | .8 |
| Offshore | 0 | 0 | 0 | 0 | 0 |
| Subtotal Transmission | 0 | .8 | 0 | 0 | .8 |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | 0 |
| Onshore Type B | 0 | 0 | 0 | 0 | 0 |
| Offshore | 0 | 0 | 0 | 0 | 0 |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 0 |
| **Total Miles** | 0 | .8 | 0 | 0 | .8 |

***For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.***

**PARTs F and G**

**The data reported in these PARTs F and G applies to:** *(select only one)*

| PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION<br>**INTRASTATE pipelines/pipeline facilities CALIFORNIA** | |
|---|---|
| **1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS** | |
| a. Corrosion or metal loss tools | 147 |
| b. Dent or deformation tools | 147 |
| c. Crack or long seam defect detection tools | 11.4 |
| d. Any other internal inspection tools | 0 |
| e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d ) | *305.4* |
| **2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS** | |
| a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation. | 40 |
| b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 27 |
| c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of: | 1 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 1 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING** | |
| a. Total mileage inspected by pressure testing in calendar year. | 0 |
| b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| **4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)** | |
| a. Total mileage inspected by each DA method in calendar year. | 132.5 |
| 1. ECDA | 126.6 |
| 2. ICDA | 1.6 |
| 3. SCCDA | 4.3 |
| b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 3 |
| 1. ECDA | 3 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | 3 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 1 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |

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| | |
|---|---|
| 3. "Monitored conditions" [192.933(d)(3)] | 2 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES** | |
| a. Total mileage inspected by inspection techniques other than those listed above in calendar year. | 0 |
| b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | 0 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR** | |
| a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a) | *437.9* |
| b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b) | 30 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4) | 4 |
| **PART G– MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)** | |
| a. Baseline assessment miles completed during the calendar year. | 86.5 |
| b. Reassessment miles completed during the calendar year. | 72.1 |
| c. Total assessment and reassessment miles completed during the calendar year. | 158.6 |

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***For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.***

**PARTs H, I, J, K, L and M**

**The data reported in these PARTs H, I, J, K, L and M applies to:**

**INTRASTATE pipelines/pipeline facilities CALIFORNIA**

**PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Onshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | 378.5 | 443.4 | 596.8 | 404.6 | 764.7 | .1 | 385.3 | 59.9 | 223.4 |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | 65.4 | 309.3 | 138.9 | 0 | 108.4 | 19 | 1023.8 | 521 | 0 |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | 0 | 301.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; | | | | | | | |
| | 0 | | | | | | | | |
| *5743.8* | Total Miles of Onshore Pipe – Transmission | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | | | | | | | | | |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ; | | | | | | | |
| | | | | | | | | | |
| | Total Miles of Offshore Pipe – Transmission | | | | | | | | |

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## PART I - MILES OF GATHERING PIPE BY NOMINAL PIPE SIZE (NPS)

**Onshore Type A**

| NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
|---|---|---|---|---|---|---|---|---|
| 4.1 | .4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0;

| 4.5 | Total Miles of Onshore Type A Pipe – Gathering |
|---|---|

**Onshore Type B**

| NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0;

| 0 | Total Miles of Onshore Type B Pipe – Gathering |
|---|---|

**Offshore**

| NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | |

| 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ;

| | Total Miles of Offshore Pipe – Gathering |
|---|---|

## PART J – MILES OF PIPE BY DECADE INSTALLED

| Decade Pipe Installed | Pre-40 or Unknown | 1940 - 1949 | 1950 - 1959 | 1960 - 1969 | 1970 - 1979 | 1980 - 1989 |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | 289.1 | 410.6 | 1960.6 | 1170.4 | 339.7 | 534.9 |
| Offshore | | | | | | |
| Subtotal Transmission | 289.1 | 410.6 | 1960.6 | 1170.4 | 339.7 | 534.9 |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | 1.7 | .8 |
| Onshore Type B | 0 | 0 | 0 | 0 | 0 | 0 |
| Offshore | | | | | | |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 1.7 | .8 |

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| | | | | | | |
|---|---|---|---|---|---|---|
| **Total Miles** | *289.1* | *410.6* | *1960.6* | *1170.4* | *341.4* | *535.7* |
| **Decade Pipe Installed** | 1990 - 1999 | 2000 - 2009 | 2010 - 2019 | | | Total Miles |
| **Transmission** | | | | | | |
| Onshore | 784.2 | 208.8 | 45.5 | | | *5743.8* |
| Offshore | | | | | | |
| Subtotal Transmission | 784.2 | 208.8 | 45.5 | | | *5743.8* |
| **Gathering** | | | | | | |
| Onshore Type A | 2 | 0 | 0 | | | *4.5* |
| Onshore Type B | 0 | 0 | 0 | | | *0* |
| Offshore | | | | | | |
| Subtotal Gathering | 2 | 0 | 0 | | | *4.5* |
| **Total Miles** | *786.2* | *208.8* | *45.5* | | | *5748.3* |

## PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH

| ONSHORE | CLASS LOCATION | | | | Total Miles |
|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | |
| **Less than 20% SMYS** | 297.7 | 54.3 | 357.4 | 1.1 | 710.5 |
| **Greater than or equal to 20% SMYS but less than 30% SMYS** | 418.5 | 105.8 | 620.4 | 0 | 1144.7 |
| **Greater than or equal to 30% SMYS but less than or equal to 40% SMYS** | 334.6 | 77.1 | 350.7 | .4 | 762.8 |
| **Greater than 40% SMYS but less than or equal to 50% SMYS** | 611.6 | 87.3 | 260.2 | 0 | 959.1 |
| **Greater than 50% SMYS but less than or equal to 60% SMYS** | 542.1 | 48.3 | 63.6 | 0 | 654 |
| **Greater than 60% SMYS but less than or equal to 72% SMYS** | 1480.2 | 31.7 | 0 | 0 | 1511.9 |
| **Greater than 72% SMYS but less than or equal to 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Unknown percent of SMYS** | 0 | 0 | 0 | 0 | 0 |
| **All Non-Steel pipe** | 0 | 0 | .8 | 0 | .8 |
| Onshore Totals | 3684.7 | 404.5 | 1653.1 | 1.5 | 5743.8 |
| **OFFSHORE** | Class I | | | | |
| **Less than or equal to 50% SMYS** | | | | | |
| **Greater than 50% SMYS but less than or equal to 72% SMYS** | | | | | |
| Offshore Total | | | | | |
| **Total Miles** | 3684.7 | | | | *5743.8* |

## PART L - MILES OF PIPE BY CLASS LOCATION

| | Class Location | | | | Total Class Location Miles | HCA Miles in the IMP Program |
|---|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | | |

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| | | | | | | |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | 3684.7 | 404.5 | 1653.1 | 1.5 | 5743.8 | *1040* |
| Offshore | 0 | 0 | 0 | 0 | 0 | |
| Subtotal Transmission | 3684.7 | 404.5 | 1653.1 | 1.5 | 5743.8 | |
| **Gathering** | | | | | | |
| Onshore Type A | 0 | 4.5 | 0 | 0 | 4.5 | |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* | |
| Offshore | 0 | 0 | 0 | 0 | 0 | |
| Subtotal Gathering | 0 | 4.5 | 0 | 0 | 4.5 | |
| **Total Miles** | 3684.7 | 409 | 1653.1 | 1.5 | 5748.3 | *1040* |

## PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS

### PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR

| Cause | Transmission Incidents, Leaks, and Failures | | | | | | Gathering Leaks | | |
|---|---|---|---|---|---|---|---|---|---|
| | Incidents in HCA Segments | Leaks | | | | Failures in HCA Segments | Onshore Leaks | | Offshore Leaks |
| | | Onshore Leaks | | Offshore Leaks | | | | | |
| | | HCA | Non-HCA | HCA | Non-HCA | | Type A | Type B | |
| External Corrosion | 0 | 1 | 5 | 0 | 0 | 0 | 0 | 0 | 0 |
| Internal Corrosion | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 |
| Stress Corrosion Cracking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Manufacturing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction | 0 | 3 | 9 | 0 | 0 | 0 | 0 | 0 | 0 |
| Equipment | 0 | 4 | 20 | 0 | 0 | 3 | 0 | 0 | 0 |
| Incorrect Operations | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Third Party Damage/Mechanical Damage | | | | | | | | | |
| Excavation Damage | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 |
| Previous Damage (due to Excavation Activity) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Vandalism (includes all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Weather Related/Other Outside Force | | | | | | | | | |
| Natural Force Damage (all) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Outside Force Damage (excluding Vandalism and all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 1 | 3 | 22 | 0 | 0 | 1 | 0 | 0 | 0 |
| Total | *3* | *11* | *61* | *0* | *0* | *4* | *0* | *0* | *0* |

### PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

| | | | |
|---|---|---|---|
| **Transmission** | 0 | **Gathering** | 0 |

### PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

| Transmission | | Gathering | |
|---|---|---|---|
| Onshore | 2 | Onshore Type A | 0 |
| | | Onshore Type B | 0 |
| OCS | 0 | OCS | 0 |
| Subtotal Transmission | 2 | Subtotal Gathering | 0 |
| Total | 2 | | |

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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***For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.***

**PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)**

[redacted]
Preparer's Name(type or print)

[redacted]
Telephone Number

**Sr. Program Manager**
Preparer's Title

Facsimile Number

[redacted]
Preparer's E-mail Address

**PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)**

**Nickolas Stavropolous**
Senior Executive Officer's signature certifying he information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**(415) 973-2020**
Telephone Number

**Nickolas Stavropolous**
Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**Executive Vice President Gas Operations**
Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**N1SL@pge.com**
Senior Executive Officer's E-mail Address

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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| U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration | **ANNUAL REPORT FOR CALENDAR YEAR 2011 NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS** | **Report Submission Type**<br>**INITIAL** |
|---|---|---|

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 22 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** Please read the separate instructions for completing this form before you begin.

| **PART A - OPERATOR INFORMATION** | DOT USE ONLY | **20120945 - 25539** |
|---|---|---|

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

**18608**

2. NAME OF COMPANY OR ESTABLISHMENT:

**STANDARD PACIFIC GAS LINE INC**

IF SUBSIDIARY, NAME OF PARENT:

**PG&E Corporation**

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

Name: [redacted]

Title: **Sr. Program Manager**

Email Address [redacted]

Telephone Number: [redacted]

4. HEADQUARTERS ADDRESS:

**Pacific Gas & Electric Co.**
Company Name

**375 N. WIGET LANE, SUITE 200**
Street Address

State: **CA** Zip Code: **94598**

[redacted]
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

**Natural Gas**

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O).

Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8.

7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

INTERstate pipeline - List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: etc.

INTRAstate pipeline - List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: **CALIFORNIA** etc.

8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☐ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply*. Complete all remaining PARTS of this form as applicable

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

☑ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for PARTs B, D, E, H, I, J, K, or L because of one or more of the following ***change(s) in pipelines and/or pipeline facilities and/or operations*** from those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable). *(Select all reasons for these changes from the following list)*

- ☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
- ☐ Divestiture of pipelines and/or pipeline facilities
- ☐ New construction or new installation of pipelines and/or pipeline facilities
- ☐ Conversion to service, change in commodity transported, or c change in MAOP (maximum allowable operating pressure)
- ☐ Abandonment of existing pipelines and/or pipeline facilities
- ☑ Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
- ☐ Change in OPID

Other – Describe: , false

***For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.***

| **PART B – TRANSMISSION PIPELINE HCA MILES** | |
|---|---|
| | Number of HCA Miles in the IMP Program |
| **Onshore** | 28 |
| **Offshore** | 0 |
| Total Miles | 28 |

**PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems)**

**Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems.**

| | **Onshore** | **Offshore** |
|---|---|---|
| Natural Gas | 101038 | |
| Propane Gas | | |
| Synthetic Gas | | |
| Hydrogen Gas | | |
| Other Gas - Name: N | | |

| **PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION** | | | | | |
|---|---|---|---|---|---|
| | Cathodically protected | | Cathodically unprotected | | Total Miles |
| | Bare | Coated | Bare | Coated | |
| **Transmission** | | | | | |
| Onshore | 0 | 54.6 | 0 | 0 | 54.6 |
| Offshore | 0 | 0 | 0 | 0 | 0 |
| Subtotal Transmission | 0 | 54.6 | 0 | 0 | 54.6 |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | 0 |
| Onshore Type B | 0 | 0 | 0 | 0 | 0 |
| Offshore | 0 | 0 | 0 | 0 | 0 |
| Subtotal Gathering | 0 | 0 | 0 | 0 | 0 |
| **Total Miles** | 0 | 54.6 | 0 | 0 | 54.6 |

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| PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION | | | | | |
|---|---|---|---|---|---|
| | Cast Iron Pipe | Wrought Iron Pipe | Plastic Pipe | Other Pipe | Total Miles |
| **Transmission** | | | | | |
| Onshore | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Transmission | *0* | *0* | *0* | *0* | *0* |
| **Gathering** | | | | | |
| Onshore Type A | 0 | 0 | 0 | 0 | *0* |
| Onshore Type B | 0 | 0 | 0 | 0 | *0* |
| Offshore | 0 | 0 | 0 | 0 | *0* |
| Subtotal Gathering | *0* | *0* | *0* | *0* | *0* |
| **Total Miles** | *0* | *0* | *0* | *0* | *0* |

***For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.***

| PARTs F and G |
|---|
| **The data reported in these PARTs F and G applies to:** *(select only one)* |

| PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION<br>**INTRASTATE pipelines/pipeline facilities CALIFORNIA** | |
|---|---|
| **1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS** | |
| a. Corrosion or metal loss tools | 0 |
| b. Dent or deformation tools | 0 |
| c. Crack or long seam defect detection tools | 0 |
| d. Any other internal inspection tools | 0 |
| e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d ) | *0* |
| **2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS** | |
| a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation. | 0 |
| b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of: | 1 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 1 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING** | |
| a. Total mileage inspected by pressure testing in calendar year. | 0 |
| b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT. | 0 |
| **4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)** | |
| a. Total mileage inspected by each DA method in calendar year. | 0 |
| 1. ECDA | 0 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| 1. ECDA | 0 |
| 2. ICDA | 0 |
| 3. SCCDA | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | 0 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |

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| | |
|---|---|
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES** | |
| a. Total mileage inspected by inspection techniques other than those listed above in calendar year. | 0 |
| b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment. | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of: | 0 |
| 1. "Immediate repair conditions" [192.933(d)(1)] | 0 |
| 2. "One-year conditions" [192.933(d)(2)] | 0 |
| 3. "Monitored conditions" [192.933(d)(3)] | 0 |
| 4. Other "Scheduled conditions" [192.933(c)] | 0 |
| **6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR** | |
| a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a) | *0* |
| b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b) | 0 |
| c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4) | 1 |
| **PART G– MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)** | |
| a. Baseline assessment miles completed during the calendar year. | 0 |
| b. Reassessment miles completed during the calendar year. | 0 |
| c. Total assessment and reassessment miles completed during the calendar year. | 0 |

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***For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.***

**PARTs H, I, J, K, L and M**

**The data reported in these PARTs H, I, J, K, L and M applies to:**

**INTRASTATE pipelines/pipeline facilities CALIFORNIA**

**PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Onshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | 0 | .6 | .4 | 3.1 | 6.6 | 0 | 4.8 | 0 | 0 |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | .7 | 26.9 | 9.6 | 0 | 1.9 | 0 | 0 | 0 | 0 |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; | | | | | | | |
| | 0 | | | | | | | | |
| 54.6 | Total Miles of Onshore Pipe – Transmission | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" |
| | | | | | | | | | |
| | 58" and over | Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ; | | | | | | | |
| | | | | | | | | | |
| | Total Miles of Offshore Pipe – Transmission | | | | | | | | |

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## PART I - MILES OF GATHERING PIPE BY NOMINAL PIPE SIZE (NPS)

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Onshore Type A** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" | |
| | | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" | |
| | | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
| | | | | | | | | | | |
| | Additional Sizes and Miles (Size – Miles;): | | | | | | | | | |
| | Total Miles of Onshore Type A Pipe – Gathering | | | | | | | | | |
| **Onshore Type B** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" | |
| | | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" | |
| | | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
| | | | | | | | | | | |
| | Additional Sizes and Miles (Size – Miles;): | | | | | | | | | |
| | Total Miles of Onshore Type B Pipe – Gathering | | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" | |
| | | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" | |
| | | | | | | | | | | |
| | 40" | 42" | 44" | 46" | 48" | 50" | 52" | 54" | 56" | 58" and over |
| | | | | | | | | | | |
| | Additional Sizes and Miles (Size – Miles;): | | | | | | | | | |
| | Total Miles of Offshore Pipe – Gathering | | | | | | | | | |

## PART J – MILES OF PIPE BY DECADE INSTALLED

| **Decade Pipe Installed** | Pre-40 or Unknown | 1940 - 1949 | 1950 - 1959 | 1960 - 1969 | 1970 - 1979 | 1980 - 1989 |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | .1 | 13.9 | 4 | .7 | 14.8 | 6.2 |
| Offshore | | | | | | |
| Subtotal Transmission | .1 | 13.9 | 4 | .7 | 14.8 | 6.2 |
| **Gathering** | | | | | | |
| Onshore Type A | | | | | | |
| Onshore Type B | | | | | | |
| Offshore | | | | | | |
| Subtotal Gathering | | | | | | |

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| | | | | | | |
|---|---|---|---|---|---|---|
| **Total Miles** | .1 | 13.9 | 4 | .7 | 14.8 | 6.2 |

| **Decade Pipe Installed** | 1990 - 1999 | 2000 - 2009 | 2010 - 2019 | | | Total Miles |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | 14.7 | .2 | 0 | | | 54.6 |
| Offshore | | | | | | |
| Subtotal Transmission | 14.7 | .2 | 0 | | | 54.6 |
| **Gathering** | | | | | | |
| Onshore Type A | | | | | | |
| Onshore Type B | | | | | | |
| Offshore | | | | | | |
| Subtotal Gathering | | | | | | |
| **Total Miles** | 14.7 | .2 | 0 | | | 54.6 |

**PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH**

| **ONSHORE** | **CLASS LOCATION** | | | | Total Miles |
|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | |
| **Less than 20% SMYS** | .3 | 0 | .4 | 0 | .7 |
| **Greater than or equal to 20% SMYS but less than 30% SMYS** | 11.5 | 0 | 13.8 | 0 | 25.3 |
| **Greater than or equal to 30% SMYS but less than or equal to 40% SMYS** | 9.5 | 0 | 7.8 | 0 | 17.3 |
| **Greater than 40% SMYS but less than or equal to 50% SMYS** | .2 | 0 | 11.1 | 0 | 11.3 |
| **Greater than 50% SMYS but less than or equal to 60% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 60% SMYS but less than or equal to 72% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 72% SMYS but less than or equal to 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Greater than 80% SMYS** | 0 | 0 | 0 | 0 | 0 |
| **Unknown percent of SMYS** | 0 | 0 | 0 | 0 | 0 |
| **All Non-Steel pipe** | 0 | 0 | 0 | 0 | 0 |
| Onshore Totals | 21.5 | 0 | 33.1 | 0 | 54.6 |
| **OFFSHORE** | Class I | | | | |
| **Less than or equal to 50% SMYS** | | | | | |
| **Greater than 50% SMYS but less than or equal to 72% SMYS** | | | | | |
| Offshore Total | | | | | |
| **Total Miles** | 21.5 | | | | 54.6 |

**PART L - MILES OF PIPE BY CLASS LOCATION**

| | Class Location | | | | Total Class Location Miles | HCA Miles in the IMP Program |
|---|---|---|---|---|---|---|
| | Class I | Class 2 | Class 3 | Class 4 | | |

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the viola ion continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

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| | | | | | | |
|---|---|---|---|---|---|---|
| **Transmission** | | | | | | |
| Onshore | 21.5 | 0 | 33.1 | 0 | 54.6 | *28* |
| Offshore | 0 | 0 | 0 | 0 | 0 | |
| Subtotal Transmission | 21.5 | 0 | 33.1 | 0 | 54.6 | |
| **Gathering** | | | | | | |
| Onshore Type A | | | | | | |
| Onshore Type B | | | | | | |
| Offshore | | | | | | |
| Subtotal Gathering | | | | | | |
| **Total Miles** | 21.5 | 0 | 33.1 | 0 | 54.6 | *28* |

## PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS

### PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR

| Cause | Transmission Incidents, Leaks, and Failures | | | | | | Gathering Leaks | | |
|---|---|---|---|---|---|---|---|---|---|
| | Incidents in HCA Segments | Leaks | | | | Failures in HCA Segments | Onshore Leaks | | Offshore Leaks |
| | | Onshore Leaks | | Offshore Leaks | | | | | |
| | | HCA | Non-HCA | HCA | Non-HCA | | Type A | Type B | |
| External Corrosion | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Internal Corrosion | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Stress Corrosion Cracking | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Manufacturing | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Construction | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Equipment | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Incorrect Operations | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Third Party Damage/Mechanical Damage | | | | | | | | | |
| Excavation Damage | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Previous Damage (due to Excavation Activity) | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Vandalism (includes all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Weather Related/Other Outside Force | | | | | | | | | |
| Natural Force Damage (all) | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Other Outside Force Damage (excluding Vandalism and all Intentional Damage) | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| Total | *0* | *0* | *0* | *0* | *0* | *0* | | | |

### PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

| **Transmission** | | **Gathering** | |
|---|---|---|---|

### PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

| Transmission | | Gathering | |
|---|---|---|---|
| Onshore | 0 | Onshore Type A | |
| | | Onshore Type B | |
| OCS | 0 | OCS | |
| Subtotal Transmission | 0 | Subtotal Gathering | |
| Total | 0 | | |

Form Approved
OMB No. 2137-0522
Expires: 01/13/2014

***For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.***

## PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)

[redacted]
Preparer's Name(type or print)

[redacted]
Telephone Number

**Sr. Program Manager**
Preparer's Title

Facsimile Number

[redacted]
Preparer's E-mail Address

## PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)

**Nickolas Stavropolous**
Senior Executive Officer's signature certifying he information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**(415) 973-2020**
Telephone Number

**Nickolas Stavropolous**
Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**Executive Vice President of Gas Operations**
Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

**N1SL@pge.com**
Senior Executive Officer's E-mail Address

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**Data Response**

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|---|---|---|---|
| PG&E Data Request No.: | TURN_010-01 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_010-Q01 | | |
| Request Date: | May 16, 2014 | Requester DR No.: | TURN-10 |
| Date Sent: | June 2, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Bennie Barnes | Requester: | Tom Long/David Berger |

## QUESTION 1

Regarding the response to TURN 1-1, Attachment 11 (Transmission Pipe Asset Management Plan, Document GP-1101 Rev 0):

a. The document contains statements regarding future work, such as list of open items to be explored on pages 4 and 5 regarding data, risk, and improvements to the transmission assets, data gaps as specified in Section 3.2, page 22 and in other locations throughout the document. What is the status of completing the list of open items and filling in the data gaps?

b. On top of page 28, PG&E states that the data sets in GIS will be updated in 2013 as part of the MAOP validation effort. Was this done and, if not, when will it be done and why wasn't it accomplished in 2013?

c. Regarding page 45, please provide a copy of the AKM data quality assessment and needs report. If not available, when will it be available?

d. Regarding page 32:

   i. When does PG&E believe that it will migrate to a probabilistic model from the SME model?

   ii. How does PG&E factor in poor quality or missing data into its existing risk model?

   iii. Who developed the current risk model?

   iv. Does PG&E believe that relying on population counts along the pipeline biases the risk calculation? If not, please explain why not. If so, are there any plans to remove such a bias?

   v. Aside from issues raised by the previous question, does PG&E believe there are there any biases embedded in the current risk model?

## ANSWER 1

a. An update of the status for the "Gaps in the current data" that are presented in Section 3.2 of the Transmission Asset Management Plan is provided in the table below:

| Data Element with Gap | 2013 Gap Identified | Status Update |
|---|---|---|
| **Pipeline feature data** | As a result of the Maximum Allowable Operating Pressure (MAOP) validation work, pipeline feature data is in the process of being quality control checked prior to incorporation in to GIS and will be fully usable in the latter part of 2013. | Complete. |
| **Inspection Data** | Through increasing In-line Inspections (ILI) and inspections by other means (robotic), transmission will develop a much more detailed and in depth knowledge of its assets, allowing for more informed, systemic asset analysis. | In progress, long range ILI plan developed. (Chapter 4A) |
| **Corrosion Control data** | Transmission Pipe is stepping up its overall approaches to corrosion control and mitigation across the system and through this step change there will be a dramatic increase in data quality and volume. | In progress, several procedure improvements developed, several more being developed. (Chapter 7) |
| **Seismic, land movement and outside forces data** | Transmission Pipe is increasing its programs of surveys and data collection around weather and other outside forces, particularity around geotechnical activity. | In progress, training of patrollers completed, gathering Light Detection and Ranging (LiDAR) data and plan to develop site-specific data in 2015 Gas Transmission and Storage (GT&S) Rate Case. (Chapter 4A) |
| **Excavation data** | There is currently a gap in data and information on shallow pipe, which is being addressed through standing up a sole project which looks to identify, investigate and if required mitigate segments of shallow pipe. | In progress, collecting data and developing a database of shallow pipe; program developed for 2015 Rate Case. (Chapter 4B) |
| **SCADA data** | To help identify the root cause and reduce over pressurization PG&E is installing more SCADA monitoring points as part of the valve automation program | In progress, further growing the Valve Automation Program. (Chapter 4A) |
| **Stress Corrosion Cracking (SCC) data** | At present the only sources of data are industry knowledge and the Stress Corrosion Cracking Direct Assessment (SCCDA) program performed on High Consequence Areas (HCAs) where the SCC threat is identified based on ASME B31.8S factors. This data is limited in its ability to provide local or systemic insight into the SCC condition of the asset. Transmission Pipe is proposing to provide investment to develop in-line inspection technology and some shift toward better usage of hydrotesting to be able to detect SCC. | In progress, continuing to apply SCC DA and planning some usage of ILI crack tools during Rate Case. Beginning to collect more data through pipe inspections. Also reviewing integrity program dig data for SCC, with none discovered. (Chapter 4A) |
| **Leak survey data (by root cause)** | Leak data is currently collated, tracked and reported to Pipeline and Hazardous Materials Safety Administration (PHMSA); however, as leak surveying methods have changed over time, it has not been possible to establish consistent historical benchmarks. Similarly, while the cause of PG&E leaks is generally recorded, the number of leaks categorized by cause has not to date been tracked as an indicator of progress in threat | Complete – metrics now being tracked and monitored. |

| | | |
|---|---|---|
| | mitigation. These metrics will be tracked and benchmarked from 2013 onwards. | |
| **Inspection data** | Currently, the results of inspections are not collected or analyzed consistently to allow for systemic asset condition analysis. Starting in 2013 a more systematic approach to creating and evaluating key process metrics and using the learnings from that process to improve the integrity management and mitigation programs. | In progress, learnings being generated and incorporated into integrity management and mitigation programs. Working with a vendor to develop an integrity data loader to load inspection data into GIS. |
| **Geotechnical threat data** | A program is proposed to analyze risk of localized geotechnical activity (landslides, soil creep) that produce horizontal/vertical strains on the pipeline and identify the locations where this threat is highest. To highlight the interacting nature of the threat, this analysis will highlight areas where land movement may coincide with construction or manufacturing threats. | In progress, training of patrollers completed, gathering LIDAR data and plan to develop site-specific data in Rate Case. A Vintage Pipe Replacement program developed to address this threat. (Chapter 4A) |
| **Maintenance data** | As part of the consistent reporting of Key Performance Indicators (KPIs) across asset families, the ratio of preventative to corrective maintenance activity will be tracked from 2013 onwards to establish a benchmark for proactive management of the asset base. | Complete. |
| **Cathodic Protection** | To help track against the new objective, TO7, around Cathodic protection outlined in Section 4, will start recording the number of Cathodic protection areas out of criteria over 365 days. Currently requires a fair amount of manual data scrubbing. Data comes from two sources, PLM and SAP, and it has manually merged. | In progress, tracking and continuing to improve through the merger of PLM and SAP. |
| **Pipeline pathways** | Alongside the efforts to improve the data of pipeline characteristics, there is also an ongoing program to gather better quality data on the exact location of the transmission pipe. This data, once collected, will be loaded and stored in PG&E's updated GIS database. Knowledge of the location of PG&E's pipelines is essential to the process of developing a plan for vegetation management and other encroachments. | Pipeline Centerline portion of program completed. |
| **Systems improvement** | Alongside the in-progress updates to GIS, there are a number of initiatives to provide the complete and accurate pipeline information necessary to establish and sustain an effective GIS and data process for PG&E's integrity management program. As part of this, an assessment of health and criticality scores will be uploaded into an integrated SAP framework. | In progress, developing health and condition assessment scorecard. Plan to complete scorecard in late 2014 using manual data entries with system generated updates occurring beginning in 2016 after SAP integration with other databases is complete. |

b. The data sets on the top of page 28 have been integrated into the enhanced Geographic Information System (GIS) as part of the MAOP validation effort. The rollout of the enhanced GIS is scheduled for the fourth quarter of 2014.

c. As referenced on page 45, the latest version of the Asset Knowledge Management (AKM) data quality assessment and needs report is provided as GTS-RateCase2015_DR_TURN_010-Q01Atch01.

d. Regarding page 32:

   i. PG&E is currently using a relative risk model that uses data to drive risk analysis results and is not using a Subject Matter Expert (SME) model as stated in the question. PG&E is currently migrating to a probabilistic model. The business rules for the algorithm are currently being drafted. By the end of 2014, PG&E plans to have the algorithm completed and plans to begin insertion of the algorithm into the risk analysis software in early 2015 with implementation during the summer of 2015.

   ii. PG&E factors in poor quality or missing data into its existing risk model by using proven and conservative assumptions. For example, PG&E uses a document known as "Procedure for Resolving Unknown Pipeline Features" (PRUPF). PRUPF provides a systematic, repeatable, and technically justifiable approach to selecting appropriate values for unknown pipe wall thickness, diameter, Specified Minimum Yield Strength (SMYS), or Longitudinal joint factor (E) using look-up tables conditional on known attributes. Where there is still "Unknown" data used in the risk analysis algorithm, PG&E uses the maximum point values for a given risk data element.

   iii. The current relative risk model used in 2013 was developed using PG&E and contractor experience over several years. In 2012, the risk algorithms were also reviewed by DNV (Det Norske Veritas) to further improve the model.

   iv. PG&E does not solely rely on population counts (Total Occupancy in testimony) for risk calculations. PG&E uses likelihood of failure (LOF) and consequence of failure (COF) in determining total risk. TURN may be referencing the point that once PG&E identifies a program with a high total risk (LOF x COF), occupancy count is used as a process for prioritizing which parts of that work to do first. PG&E has adopted the concept of Total Occupancy Count (TOC) and Average Occupancy Count (AOC) as a way of prioritizing work by placing the emphasis on putting the safety of people at the heart of our programs. If there is any bias, it is toward putting the safety of people first in our risk based decision making.

   v. PG&E believes that there are no biases embedded in the current risk model.

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|---|---|---|---|
| PG&E Data Request No.: | TURN_010-03 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_010-Q03 | | |
| Request Date: | May 16, 2014 | Requester DR No.: | TURN-10 |
| Date Sent: | June 4, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Louis Krannich | Requester: | Tom Long/David Berger |

### QUESTION 3

Please provide a narrative description of how PG&E calculates the quantitative risk mitigation of:

a. Vintage pipe replacement program
b. Capacity improvement programs
c. Automated valve program
d. Shallow pipe program
e. Water and levee crossing program
f. Class location program
g. NOP program?

### ANSWER 3

Inherently the quantification of risk mitigation includes both the scope and pace of work and thus one must take into consideration the comprehensive enterprise and operational asset and risk management process that PG&E has developed to formulate the programs and forecasted scope and pace of work. PG&E utilized a risk-based process to identify the top risks across Gas Operations Asset Families. Asset Family Owners proposed mitigating programs to address the top risks identified with the goal of reducing those risks. PG&E then applied a risk-based investment prioritization process across all Asset Families to evaluate the appropriate scope and pace of all mitigating programs while considering constraints. PG&E prioritizes individual programs based on the characteristics of the total portfolio and thus any comparison of a subset of programs without adequate consideration of classification of work, risk scores, resource and system constraints, dependencies and support needs of the total portfolio of programs is hypothetical. PG&E's response to TURN 001-Q01, provides detailed documentation of this risk prioritization process used to forecast costs for this case as well as the quantitative risk mitigation methodology used.

Some of the key considerations in the investment prioritization process include classification, risk score, and applicable constraints – which were used to compare programs in determining the final portfolio. Gas Operations classifies all of its projects and programs into four classifications: Compliance, Customer Driven, Fixed Costs, and

Strategic. Each program or project is then risk scored on a scale of 1-49 based on consequence and likelihood scores for Safety, Environmental, and Reliability. The risk score is periodically re-evaluated. A score of 49 would indicate an event with the highest possible consequence and highest likelihood. In the prioritization process, PG&E also reviews any constraints on the portfolio. The types of constraints considered are resource constraints, system availability constraints, and work execution constraints.

a. The Vintage Pipeline Replacement Program is primarily focused on removal of the stable or resident threat of historic fabrication and construction methods that are not as readily assessed using In-Line Inspection (ILI) or hydrostatic testing coupled with the threat of land movement. Approximately 47 percent of PG&E's natural gas pipeline was designed, manufactured, constructed, and installed before the advent of California pipeline safety laws in 1961. The risk score for vintage pipeline replacement is a 39, based on the impacts if the investment is not made. The consequence score is driven by a rupture in a highly populated area. PG&E expects to replace 20 miles of vintage pipe per year, thereby contributing to the reduction of risk posed by these interacting threats for over 90 percent of the population living within the potential impact radius of PG&E's pipelines by 2017. PG&E's goal is to replace, by the end of 2025, all of the pipe segments containing vintage fabrication and construction threats that are subject to the threat of land movement that are in proximity to the population. The likelihood score assumes this consequence could occur within a 20-100 year time frame.

b. Capacity improvement projects primarily address the risk of loss of supply and service. This risk arises when customer load growth is projected to accumulate in a certain area so that hydraulic modeling shows the transmission system to be constrained and unable to provide sufficient gas to satisfy customer demands at design day conditions. Such constraints must be avoided by reinforcing the transmission system with new capacity before the design day conditions occur. PG&E monitors and forecasts load growth to anticipate such constraints so it can proactively reinforce the transmission system. The objective is to prevent an increased risk of loss of supply. As with new business, growth-driven pipeline capacity projects can take several years to design, permit, and construct, so they must begin well before that forecasted growth materializes. The risk score for capacity improvement projects is a 37, based on the impacts if the investment is not made. The consequence score is driven by how programmatically this will address a multitude of systems over the rate case period, many of which would become at risk to suffer outages of several days if incremental capacity is not provided, some systems would be at risk for more frequent outages and could result in the need for full curtailment of entire distribution systems to maintain integrity of related/connected systems. The likelihood score assumes all expected growth over the entire transmission system for the next 10 to 20 years and that the growth in this period will result in the need for incremental capacity to meet design criteria, potentially making the system unable to support CWD (one in two year cold weather day) during this period. Since the design criteria are not linear functions, system growth will decrease the ability of the system to meet design criteria exponentially as demand approaches the upper limit of the system's design.

c. Valve automation is an industry best practice to ensure that in the event of a rupture, the flow of gas can be stopped in a timely manner to enable emergency response.

The Valve Automation program was also part of the recommendations made by the National Transportation Safety Board (NTSB) to PG&E, as well as one of the recommendations made by the Independent Review Panel (IRP) to PG&E, as well as one of the mandated programs by the California Public Utilities Commission (CPUC) under the Pipeline Safety Enhancement Plan (PSEP) to PG&E. Subsequent to the CPUC's mandate, the California legislature adopted Public Utilities Code § 957 which mandates the installation of automatic shut-off valves to reduce the damage from a gas transmission pipeline failure within an HCA or active seismic earthquake fault. The risk score for the Valve Automation program is a 26, based on the impacts if the investment is not made. The consequence score is driven by the following: the initial impact of rupture likely to cause the most human injury, and reducing the flow of gas more quickly could help emergency responders to prevent an additional member of the public from being harmed. This automation program will result in 384 miles of additional gas transmission pipeline (223 miles of Class 3 or Class 4) that can rapidly be isolated through remote control valve technology. The likelihood assumes this event takes place within the next 20-100 years.

d. The Shallow Pipe Program targets the prevention of the time independent threat of excavation damage in locations where the pipeline has reduced cover, making the pipeline vulnerable to heavy equipment loading damage and excavation damage from third parties, many of which result in immediate leaks or ruptures. The risk score for shallow pipe is a 39, based on the impacts if the investment is not made. The consequence score is driven by an incident associated with segments of shallow pipe located in Class 3 and 4, High Consequence Area (HCA) locations. Given the frequency of dig-ins the likelihood assumes this event takes place within the next 20-100 years.

e. As referenced in the Chapter 4B testimony, page 4B-15, the Water and Levee Crossing Program targets the prevention of the time independent threat, including, for example, channel scouring, damage by debris from seasonal floodwaters, water forces on exposed pipe, boat anchors, dredging operations, settlement or subsidence of levees, and bank scouring or erosion. The risk score for the Water and Levee Crossing program is a 26, based on the impacts if the investment is not made. The consequence is driven by the loss of supply and service caused by taking a line out of service that could result in significant operational challenges and elevated costs to meet customer demands. The likelihood assumes this event takes place within the next 20-100 years.

f. The Class Location program stems from a compliance requirement to ensure that pipelines are operating within the appropriate class as determined by population density. Title 49 of the Code of Federal Regulations – Transportation (49 CFR) Part 192.613 requires that each operator have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location. The Class Location program targets risks associated with capacity and/or reliability threats. The risk score for the Class Location program is a 43, based on the impacts if the investment is not made. The consequence is driven by an incident within high population centers that may or may not have grown to include well-defined outside areas such as playgrounds, recreation areas, or other places of public assembly. Although a reduction in Maximum Allowable Operating Pressure

(MAOP) may be a viable option in certain cases, to address the change in class, customer gas demand may not allow for a permanent reduction in pressure. Strength testing is typically the most cost effective approach to addressing Class Location, but the physical limitations of some pipelines make this an unfeasible option.

g. Projects to reduce Normal Operating Pressure (NOP) while ensuring sufficient capacity to meet design day service criteria are aimed at minimizing instances of incidental over-pressurizations. Since PG&E began to programmatically reduce its NOP, the number of incidents in which pressure exceeded MAOP declined from 774 in 2011 to 31 in 2013. The risk score for projects to reduce NOP is a 33, driven by safety impacts if the investment is not made. This is based on a safety consequence score associated with the risk from the loss of gas supply to tens of thousands of customers and the impact of homes with defective safety devices in their appliances that could result in gas entering homes and could result in an explosion. The likelihood score is based on sites proposed for mitigation lacking the capacity to take NOP reductions without creating the risk of loss of supply under design day conditions, which assumes the likelihood of this incident to be within the 20-100 year time frame.

The quantification of the risk scores for the programs shown above may be used to understand the relative risk impact for these programs. Keeping in mind that programs have differing overarching threat mitigation focuses and using the Investment Planning prioritization process referenced above, all of these programs are essential in preventing the respective targeted threats, thereby reducing the associated risks. While the risk score for the Water and Levee Crossing Program is relatively low, it is vital to address the vulnerabilities identified by the United States Army Corps of Engineers in a study which identified California levees as among the most vulnerable for failure and having the greatest potential risk for loss of life, property damage, and economic impact. The Water and Levee Crossing Program is also required as a result of the master lease agreements with the California State Lands Commission to regularly perform surveys in jurisdictional waterways. The Valve Automation program is critical in emergency response to a catastrophic pipeline rupture and is a part of the recommendations made by the NTSB and IRP to PG&E while also being mandated by the CPUC under PSEP, and the legislature under P.U.C. § 957. However, relative to the other programs outlined in this response, Valve Automation and the Water & Levee Crossing Program are lower risk programs and the scope and pace of the program reflect the outcome of the risk-based investment prioritization process, which includes not only the relative risk score, but also the program's classification and associated constraints.

In an ideal world, we would be able to perform and accelerate solely those programs with the highest risk impacts, but given consideration of other factors such as classification of work, system constraints, resource constraints, and work optimization, it is not always practical or possible. Many of our high risk mitigation programs such as hydrostatic testing are constrained by execution limitations. Other programs such as Vintage Pipe Replacement are coordinated with other programs such as hydrostatic testing and In-Line Inspection to optimize mitigation. PG&E believes that the forecasts for these programs are appropriate based on the classification, risk score and constraints of all the programs in the portfolio.

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| PG&E Data Request No.: | TURN_010-05 | | |
| --- | --- | --- | --- |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_010-Q05 | | |
| Request Date: | May 16, 2014 | Requester DR No.: | TURN-10 |
| Date Sent: | July 10, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long |

## QUESTION 5

Please provide a summary of:

a. NOPVs and other notices received from regulatory authorities regarding the gas transmission or storage systems, including recommendations from the NTSB, notices from PHMSA and the CPUC, including any notice resulting from audits and inspections, for each year from 2010 through and including 2013.

b. Recommendations regarding the gas transmission or storage systems of internal audits, and audits performed by outside parties hired by PG&E for each year from 2010 through and including 2013.

## ANSWER 5

*Attachments 05 through 55 to this response have been marked CONFIDENTIAL and are submitted pursuant to a Non-Disclosure Agreement because they include confidential employee information.*

a. During the period of 2010 through 2013, PG&E received 10 letters from the California Public Utilities Commission (CPUC) for transmission and/or storage audits that took place during the period of 2010 through 2013 with 402 associated Notice of Probable Violations (NOPVs). Attachment GTS-RateCase2015_DR_TURN_010-Q05Atch01 tab "CPUC Audit Findings" provides a summary of the CPUC audit findings. In addition, PG&E received 12 recommendations from the National Transportation Safety Board (NTSB) which impact some or all of PG&E's gas transmission and storage facilities. See Attachment GTS-RateCase2015_DR_IndicatedProducers_002-Q034Atch01 for a summary of those recommendations.

   Under the CPUC's Gas Safety Citation Program, the CPUC has issued one citation on PG&E's gas transmission and storage system, Citation #13-003 dated November 5, 2013, regarding a violation of 49 CFR §192.243 and Public Utilities Code Section 451. See attachments GTS-RateCase2015_DR_TURN_010-Q05Atch02 and Atch03 for a copy of the citation and enclosure.

   In September 2012, the CPUC issued a report, "Staff Report on Investigation of Pacific Gas and Electric Company's Gas Transmission Pipeline Welding Practices" related to work performed on PG&E's gas transmission system. See attachment GTS-RateCase2015_DR_TURN_010-Q05Atch04.

The Transportation Safety Administration performed inspections to evaluate PG&E's compliance with federal security guidelines. Because of these reports are highly sensitive, they are not provided as part of this response.

b. PG&E performs two additional levels of audits on its gas transmission and storage facilities. The first are Quality Assurance (QA) audits performed internally by the Gas Operations QA/QC organization. During the period of 2010 through 2013, this team conducted 14 audits regarding its gas transmission and storage system. A summary listing of the reports is provided in GTS-RateCase2015_DR_TURN_010-Q05Atch01 tab "QA Report Summary." The reports are attached as GTS-RateCase2015_DR_TURN_010-Q05Atch05CONF to Atch18CONF.

   The second level of audits is performed by PG&E's Internal Auditing (IA) organization. This organization is independent of the Gas Operations organization. During 2010 through 2013, the IA organization conducted 34 internal audits involving gas transmission and storage facilities. A summary listing of the reports is provided in GTS-RateCase2015_DR_TURN_010-Q05Atch01 tab "Internal Audit Report Summary." The reports are attached as GTS-RateCase2015_DR_TURN_010-Q05Atch19CONF to Atch52CONF.

   PG&E is also providing reports from 3rd party audits performed between 2010 and 2013. A summary listing of the reports is provided in GTS-RateCase2015_DR_TURN_010-Q05Atch01 tab "External Party Report Summary." The reports are attached as GTS-RateCase2015_DR_TURN_010-Q05Atch53CONF to Atch55CONF.

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|---|---|---|---|
| PG&E Data Request No.: | TURN_010-06 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_010-Q06 | | |
| Request Date: | May 16, 2014 | Requester DR No.: | TURN-10 |
| Date Sent: | June 2, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Jim Howe | Requester: | Tom Long/David Berger |

**QUESTION 6**

If PG&E's revenue requirement request received a 20% across the board reduction, what would be the effect on the risk to the general public? Explain the basis of the answer.

**ANSWER 6**

As stated on page 2-5, lines 21-23, of PG&E's 2015 Gas Transmission and Storage Rate Case testimony, reduced funding levels would slow the trajectory of risk-reduction, resulting in a higher level of risk over a longer period of time. Since PG&E's forecast would fund mitigation efforts that are prioritized to address the highest risk to the public, the effect of the reduced funding would be to slow the mitigation of risk to the general public. PG&E would need to perform a reprioritization of its proposed portfolio of work based on reduced funding levels in order to determine the specific impacts that would result. This analysis has not been done.

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|---|---|---|---|
| PG&E Data Request No.: | TURN_010-07 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_010-Q07 | | |
| Request Date: | May 16, 2014 | Requester DR No.: | TURN-10 |
| Date Sent: | June 2, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Jim Howe | Requester: | Tom Long/David Berger |

## QUESTION 7

If PG&E's revenue requirement request received a 20% increase what would be the effect on the risk to the general public? Explain the basis of the answer.

## ANSWER 7

This is a hypothetical question in this proceeding as the Commission cannot authorize more revenues than requested without notice to the public. Whether an increase in revenues would accelerate risk reduction to the general public would need to be evaluated in light of the execution constraints PG&E discusses in its 2015 Gas Transmission and Storage Rate Case testimony on page 2-16, lines 20 through 30, as well as discussed in documents provided in response to GTS-RateCase2015_DR_TURN_001-Q01. In developing its forecast in this case, PG&E compared the potential scope of the proposed programs of work against system constraints as well as the availability of resources to support all funded programs, and concluded that its forecast adequately balanced risk reduction against ability to execute. An increase in revenues over what PG&E requested would require a similar analysis to determine whether PG&E is capable of reducing risk in light of execution constraints. Such an analysis has not been done.

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|---|---|---|---|
| PG&E Data Request No.: | TURN_010-13 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_010-Q13 | | |
| Request Date: | May 16, 2014 | Requester DR No.: | TURN-10 |
| Date Sent: | June 3, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Jim Howe | Requester: | Tom Long/David Berger |

### QUESTION 13

Regarding PG&E's assessment of the reasonable level of risk relating to its GT&S operations:

a. Please provide a narrative description of that assessment.

b. If PG&E's requested funding level were reduced by 20%, how much longer would it take to reach that goal of acceptable risk?

c. If PG&E's requested funding level were reduced by 50%, how much longer would it take to reach that goal of acceptable risk?

d. If PG&E's requested funding level were increased by 50%, how much less time would it take to reach that goal of acceptable risk?

### ANSWER 13

a. Based upon the direction of the legislature and the CPUC as well as recommendations from the National Transportation Safety Board (NTSB), PG&E is pursuing risk reduction in an aggressive manner, including implementation of industry best practices. In developing its forecast, PG&E identified all of the threats posed to its Gas Transmission and Storage (GT&S) facilities and categorized them using the American Society of Mechanical Engineers (ASME) B31.8S framework. Once the threats were identified, PG&E evaluated the risks that those threats posed to the public and identified mitigation programs to address those risks. While with some programs we are able to identify the percent of risk reduction we expect to achieve given execution of specified work, other programs are not capable of such precision. In these cases, PG&E applied subject matter expertise, historic knowledge of its assets, industry standards and best practices, as well as external expertise to develop a 3-year program that is expected to reduce risk in the most optimal way, given resource and system constraints. PG&E expects to be informed by the CPUC in this case regarding the Commission's acceptable level of risk.

b. See response to (a) above. PG&E cannot at this time specifically define the metrics or the exact time horizon to achieve an acceptable level of risk in the system. Not only is the determination of acceptable risk levels yet to be determined, but we expect that risk assessment as well as risk tolerance will change over time, which will impact the time horizon to achieve that acceptable level. As discussed in the informal risk assessment and mitigation workshops that have been held thus far, we believe that one of the most difficult tasks in this proceeding will be to determine the acceptable level of risk tolerance. The CPUC has acknowledged this concern and is working to develop a formalized process to ensure the effective use of risk-based methods in its rate case plan (RCP). The RCP Order Instituting Rulemaking (OIR) R.13-11-006 will work to develop the necessary metrics and evaluation tools to ensure the work proposed by utilities meets an acceptable level of risk. PG&E believes that the portfolio of programs proposed in this case will reduce risk significantly over the rate case period, but will not allow reaching full mitigation to that acceptable level. PG&E expects that reaching that level will be a long term effort.

c. PG&E has received recommendations from the NTSB, local governments, as well as the CPUC that additional investments and maintenance activities and programs are necessary to ensure the safety of our system. PG&E agrees with these recommendations and believes our forecast focuses on risk-reduction programs and maintenance activities to ensure safety and reliability, and reduce risks at an appropriate pace over the rate case period. In the proposed scenario in this question, the approved funding would be approximately equivalent to the approved revenue from the 2011 GT&S Rate Case. Projects that are newly required since the 2011settlement such as hydrotesting, pipeline replacement, valve automation, and inline inspection would not receive adequate funding, and would severely compromise the integrity and safety of our system.

d. PG&E objects to this question as it poses an unrealistic hypothetical. Without waiving this objection, PG&E provides the following answer: In building the forecast, PG&E worked to optimize its use of available resources, as well as ensuring the proposed projects would not result in any service interruptions to our customers. Increasing the scope of work as a result of increased revenue may not be feasible due to identified constraints, jeopardizing any opportunity to further reduce risk.

**PACIFIC GAS AND ELECTRIC COMPANY**
**Gas Transmission and Storage Rate Case 2015**
**Application 13-12-012**
**Data Response**

| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_012-04 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_012-Q04 | | |
| Request Date: | May 29, 2014 | Requester DR No.: | TURN-12 |
| Date Sent: | June 12, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | William E. Mojica | Requester: | Tom Long/David Berger |

**QUESTION 4**

How many miles of shallow pipe did PG&E mitigate during

a. 2002 through 2010?

b. 2011 through 2014?

c. How many miles does PG&E anticipate mitigating during 2015 through 2017?

**ANSWER 4**

PG&E's Shallow Pipe program forecast in the 2015 Gas Transmission and Storage (GT&S) Rate Case is a new program. Shallow pipe has not historically been mitigated explicitly through a programmatic approach and instances of shallow pipe in the past were identified and addressed on a case-by-case basis, often in conjunction with other projects related to reliability upgrades, capacity upgrades, and projects resulting from Work Required by Others (WRO) in the vicinity of shallow pipe locations.

a. b. For 2002 through 2014, PG&E did not have a programmatic approach for addressing shallow pipe locations, and since shallow pipe was often identified and mitigated in conjunction with other projects, PG&E does not have a comprehensive list of total miles of shallow pipe mitigated during this time period.

c. Please refer to PG&E's 2015 GT&S Rate Case testimony supporting Chapter 4B on page 4B-25, Table 4B-7. PG&E forecasts expense and capital mitigation during the rate case period as follows:

- 2015: 0.3 miles of expense mitigation and 2.5 miles of capital mitigation
- 2016: 0.3 miles of expense mitigation and 2.5 miles of capital mitigation
- 2017: 0.4 miles of expense mitigation and 3.4 miles of capital mitigation.

**PACIFIC GAS AND ELECTRIC COMPANY**
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_012-05 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_012-Q05 | | |
| Request Date: | May 29, 2014 | Requester DR No.: | TURN-12 |
| Date Sent: | June 10, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long/David Berger |

**QUESTION 5**

Please provide a comparison of the forecast amounts in PG&E's previous GT&S applications to actual expenditures for expenses and capital expenditures for each of the years 2005 through 2013 with respect to the following:

a. shallow pipe replacement remediation (per mile or other metric),

b. levee and water crossings (per crossing), and

c. work for others (per mile).

**ANSWER 5**

As discussed in Chapter 3, PG&E has prepared its forecasts of expenses and capital expenditures/additions in the 2015 GT&S rate case at a greater level of detail than its forecasts in the 2011 GT&S rate case. Also as noted in Chapter 3, PG&E redesigned its Major Work Categories (MWCs) and Maintenance Activity Types (MATs) in late 2012. The format of the forecasts for the 2015 GT&E rate case are also different from the format of the forecasts in all previous GT&S proceedings. Thus there is no basis on which to assign the forecasts of expenses and capital expenditures/additions from previous GT&S applications to the categories and metrics (i.e. per mile or per crossing) identified in this question.

See also the response to data request TURN-011-01 (GTS-RateCase2015_DR_TURN_011-Q01).

# PACIFIC GAS AND ELECTRIC COMPANY
## Gas Transmission and Storage Rate Case 2015
## Application 13-12-012
## Data Response

| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_014-02 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_014-Q02 | | |
| Request Date: | June 3, 2014 | Requester DR No.: | TURN-14 |
| Date Sent: | June 25, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Sara Peralta Burke | Requester: | Tom Long/David Berger |

**QUESTION 2**

Please provide a narrative describing, for each year between 2005 and 2013, what if any work was performed for an atmospheric corrosion program, expenditure amounts, what was accomplished, and if there were any violations of California or federal requirements with respect to atmospheric corrosion control.

**ANSWER 2**

The data requested prior to 2009 is not readily available. During 2009 through 2013, atmospheric corrosion inspection on transmission assets work was performed as a secondary task during primary maintenance inspections such as pipeline patrol, leak survey, regulator station and valve maintenance, meter maintenance, and other inspections. As stated in PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case Chapter 7 testimony, because much of PG&E's atmospheric corrosion inspection and mitigation work was a secondary task, PG&E is unable to identify specific work that was completed. With the exception of the work specified in IP002-Q114, PG&E performed all atmospheric corrosion work as required.

In addition, as noted in 2015 GT&S Testimony for Chapter 3 and Chapter 7, PG&E redesigned its Major Work Categories (MWC) and Maintenance Activity Types (MAT) in late 2012 to better identify and group the costs of work being performed in Gas Operations. Prior to 2012, corrosion control expense work was combined with other maintenance work in MWC BX. Therefore, the recorded figures listed in the table below represent the work that is solely attributable to atmospheric corrosion but do not necessarily capture all of the atmospheric corrosion inspection and mitigation work performed.

| Order Description | 2009 Recorded | 2010 Recorded | 2011 Recorded | 2012 Recorded | 2013 Recorded |
|---|---|---|---|---|---|
| Atmospheric Corrosion Inspection and Mitigation | $24,976 | $283,404 | $296,507 | $1,114,912 | $721,201 |

During the period of 2005 through 2013, the following number of violations, relating to the atmospheric corrosion program, were assessed by the California Public Utilities Commission (CPUC):

| 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|
| 5 | 7 | 1 | 3 | 2 | 0 | 1 | 1 | 2 |

In addition, during the 2005 through 2013 period PG&E submitted two self-reports on 3/6/2013 and 6/18/2013. PG&E submitted an additional self-report in February 2014 which identified overarching deficiencies specific to the atmospheric corrosion program. As noted in PG&E's 2015 GT&S Rate Case Chapter 7 testimony page 7-45, PG&E is performing a significant amount of work to remediate items relating to atmospheric corrosion, the costs for which we are not seeking recovery from customers. See response to GTS-RateCase2015_DR_IndicatedProducers_002-Q114 for description of each of the audit findings and self-reports.

# PACIFIC GAS AND ELECTRIC COMPANY
## Gas Transmission and Storage Rate Case 2015
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## Data Response

| PG&E Data Request No.: | TURN_014-17 | | |
|---|---|---|---|
| PG&E File Name: | GTS-RateCase2015_DR_TURN_014-Q17 | | |
| Request Date: | June 3, 2014 | Requester DR No.: | TURN-14 |
| Date Sent: | June 17, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Sara Peralta | Requester: | Tom Long/David Berger |

### QUESTION 17

What was the amount, both capital and expense, spent on AC interference testing and mitigation per year from 2001 through 2013?

### ANSWER 17

The data requested prior to 2009 is not readily available. The 2009 through 2013 data for Alternating Current (AC) Interference is provided below, all values are presented in thousands of dollars.

| | 2009 Recorded | 2010 Recorded | 2011 Recorded | 2012 Recorded | 2013 Recorded |
|---|---|---|---|---|---|
| **AC Interference - Expense** | $ - | $ 1 | $ - | $ - | $ 850 |
| **AC Interference - Capital** | $ - | $ - | $ 121 | $ 268 | $ 423 |

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| PG&E Data Request No.: | TURN_023-02 | | |
|---|---|---|---|
| PG&E File Name: | GTS-RateCase2015_DR_TURN_023-Q02 | | |
| Request Date: | June 18, 2014 | Requester DR No.: | TURN-23 |
| Date Sent: | July 2, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Ken Niemi<br>Jeff Swanson | Requester: | Tom Long |

## QUESTION 2

With respect to the Testimony, p. 17-13, regarding average monthly bill impact for residential and small business customers:

a. Please provide all supporting documentation for the reported average bill impacts

b. Please indicate whether the average bill impacts shown for residential customers are for non-CARE customers.

   i. If the testimony just gives bill impacts for non-CARE customers, please provide the average monthly bill impact for CARE customers and provide all supporting documentation.

c. With respect to the 2015-2017 average forecast usage for residential and small commercial customers (fn. 7):

   i. Please compare these forecasts to the forecasts used in PG&E's 2014 test year GRC and explain any differences.

   ii. Please provide actual data for each year from 2008 through 2013.

d. Provide the average monthly bill impact of PG&E's request on each of residential CARE, residential non-CARE, and small commercial customers, if PG&E's request for the attrition years is included.

## ANSWER 2

a. Please see Attachment: "GTS-RateCase2015_DR_TURN_023-Q02Atch01". The bill impacts stated in p.17-13 of the Testimony are calculated in tab: "Calc_BillImpacts".

b. The residential bill impacts on page 17-13 of Chapter 17 Testimony are based on the Non-care end user rate multiplied by the forecasted average monthly usage for the Care and Non-care customers combined.

   i. For CARE residential bill impact, please see the analysis in Attachment: "GTS-RateCase2015_DR_TURN_023-Q02Atch02", See tab: "Res_Care_Non-Care Bill Analysis". Supporting documentation is provided in the other tabs of the attachment. The analysis is based on:

      1. The historical monthly average usage for Care and Non-care residential customers during the three years (2011-2013).
      2. The ratio between Care and Non-Care usage and end-user price during the three years (2011-2013).

3. The end-user rates presented in Table 17-5, page 17-11 of the Testimony.[1]
4. The ratios calculated in (1) and (2) are applied to the average usage and the Non-care rate used in p. 17-13 in order to calculate the average bill impact for the Care and Non-care customers separately.

c.

i. PG&E's 2014 General Rate Case sources the gas throughput forecast from the 2009 Biennial Cost Allocation Proceeding (BCAP).

2009 BCAP Average Temperature Forecast for 2010-2012 period:

Residential: 201,320 MDTH

Small Commercial: 78,132 MDTH

2015 GT&S Average Temperature Forecast for 2015-2017 period:

Residential: 191,903 MDTH

Small Commercial: 78,063 MDTH

There are several fundamental differences between these forecasts, namely the 2015 GT&S forecast utilizes approximately 5 years of additional recorded data which embeds advances in energy efficiency, changes in household usage habits, and the effect of the global recession which was not forecast in 2009 to be as long and deep as it turned out in reality. The 2015 GT&S forecasts also account for the rate increases associated with the 2014 GRC and the 2015 GT&S rate cases.

ii. See below for annual MDTH by class for 2008 through 2013. Note that this recorded data contains the effects of temperature for these two temperature-sensitive customer classes.

Annual MDTH

| | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** |
|---|---|---|---|---|---|---|
| **Residential** | 200,565 | 202,791 | 204,836 | 213,607 | 199,592 | 200,444 |
| **Small Commercial** | 78,352 | 77,195 | 77,462 | 79,948 | 77,332 | 77,860 |

d. The summary tables below illustrate the bill impacts as proposed by PG&E. For more details please see Attachment: "GTS-RateCase2015_DR_TURN_023-Q02Atch02", in the respective tabs for residential and commercial customers.

[1] Note: The "Customer Class" description on Line 2 in Table 17-5 is incorrectly stating (Care). This error should be corrected to state (Non-Care). PG&E will include this on the next Correction Log.

Residential G1 customers illustrative bill impact:

| | 2014 | 2015 | Inc. | % | 2016 | Inc. | % | 2017 | Inc. | % |
|---|---|---|---|---|---|---|---|---|---|---|
| Avg. Care Rate, $ per therm<br>Avg. Care monthly usage (forecast), therms | 1.129<br>30.6 | 1.271<br>30.6 | 0.142 | | 1.287<br>30.6 | 0.016 | | 1.319<br>30.6 | 0.032 | |
| Avg. Care Bill Impact, $ | 34.5 | 38.8 | 4.3 | 12.6% | 39.3 | 0.5 | 1.3% | 40.3 | 1.0 | 2.5% |
| Avg. Non-care Rate, $ per therm<br>Avg. Care monthly usage (forecast), therms | 1.222<br>38.0 | 1.375<br>38.0 | 0.154 | | 1.392<br>38.0 | 0.017 | | 1.427<br>38.0 | 0.035 | |
| Avg. Non-Care Bill Impact, $ | 46.4 | 52.2 | 5.8 | 12.6% | 52.9 | 0.7 | 1.3% | 54.2 | 1.3 | 2.5% |

Small Commercial GNR1customers illustrative bill impact:

| | 2014 | 2015 | Inc. | % | 2016 | Inc. | % | 2017 | Inc. | % |
|---|---|---|---|---|---|---|---|---|---|---|
| Avg. Care Rate, $ per therm<br>Avg. Care monthly usage (forecast), therms | 0.881<br>218.0 | 1.021<br>218.0 | 0.141 | | 1.037<br>218.0 | 0.016 | | 1.069<br>218.0 | 0.032 | |
| Avg. Care Bill Impact, $ | 191.9 | 222.6 | 30.6 | 16.0% | 226.1 | 3.5 | 1.6% | 233.0 | 7.0 | 3.1% |
| Avg. Non-care Rate, $ per therm<br>Avg. Non-Care monthly usage (forecast), therms | 0.937<br>351.2 | 1.087<br>351.2 | 0.150 | | 1.104<br>351.2 | 0.017 | | 1.138<br>351.2 | 0.034 | |
| Avg. Non-Care Bill Impact, $ | 329.2 | 381.7 | 52.6 | 16.0% | 387.7 | 6.0 | 1.6% | 399.6 | 11.9 | 3.1% |

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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_023-03Supp01 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_023-Q03Supp01 | | |
| Request Date: | June 18, 2014 | Requester DR No.: | TURN-23 |
| Date Sent: | August 1, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long |

## QUESTION 3

Please provide any documents in PG&E's possession analyzing or discussing bill impact or other affordability issues related to this application that were prepared:

a. Prior to the filing of this application.

b. After the filing of this application.

## ANSWER 3

a. Some documents responsive to this data request reflect analyses that were performed at the direction of counsel for the purposes of obtaining legal advice, and are therefore protected from disclosure by the attorney-client privilege and the attorney work product doctrine. Subject to and without waiving the foregoing objection, PG&E responds as follows:

PG&E's 2013 Integrated Planning Process Session 1 discusses affordability issues related to the 2015 Gas Transmission & Storage (GT&S) Rate Case application. This document was previously provided to TURN as GTS-RateCase2015_TURN_001-Q01Atch26. For additional detail about how the forecast was developed, see PG&E's response to TURN_001-Q01.

PG&E calculated bill impacts for large commercial and noncore customers. This calculation included impacts of: (1) the 2014 Annual Gas True Up; (2) 2014 General Rate Case request; (3) 2015 General Rate Case attrition; and (4) 2015 GT&S request including 2016 and 2017 GT&S attrition. This was done on a customer-by-customer basis and cannot be shared because it would disclose customer-specific confidential information. (See PG&E's Gas Rules 9M and 27).

In addition, PG&E communicated the results of the above calculations to impacted large commercial and noncore customers. An example of the communication is provided as GTS-RateCase2015_TURN_023-Q03Atch01.

b. A draft of PG&E's 2014 Session 1 document will be available in July. The document will be finalized by the end of 2014.

**ANSWER 3 (A) SUPPLEMENTAL 01**

Attached as GTS-RateCase2015_DR_TURN_23-Q03Supp01Atch01 are additional responsive materials from a presentation to executive leadership on August 28, 2013. The data reflected in these materials are based on high level assumptions and were provided for discussion purposes. Please note that the original presentation included certain attorney-client privileged/work product material. The pages containing this material have been removed from the attachment. Thus, the footer on this document that indicates that the document contains protected material does not apply to the content that has been provided.

PG&E®

# 2015 GT&S Rate Case Special Attention Review August 28, 2013

Trina Horner, Regulatory Proceedings and Rates
Jane Yura, GasOps Standards and Policy

*Privileged and Confidential*
*Prepared in Anticipation of Litigation*
*Attorney Work Product*

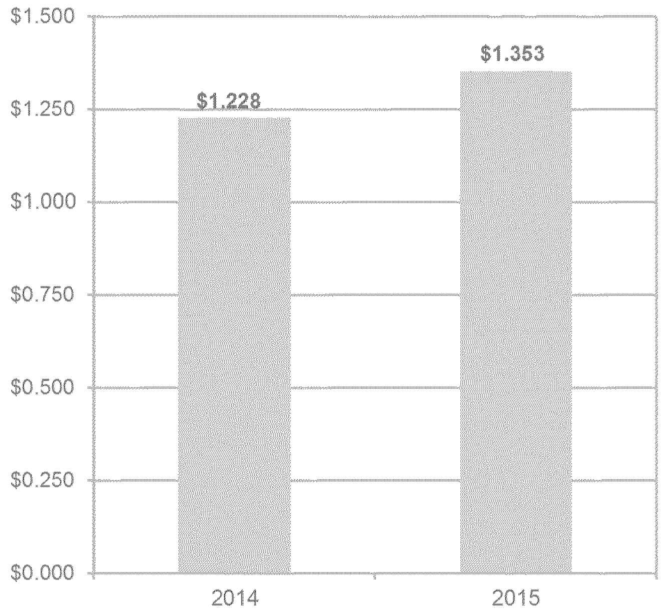
# Illustrative Rate and Bill Forecast

Noncore Local Transmission customers see largest increases; average Residential rate and bill increase = 10%

## Transportation and Storage Rate Changes

| Backbone Transmission Rates ($/Dth) | 2014 to 2015 Change | | |
|---|---|---|---|
| Core | ~30% | | |
| Noncore | ~23% | | |
| Transportation of California-Produced Gas | 22.1% | | |
| Incremental Line 401 Expansions Shippers (G-XF) | 3.0% | | |
| **Storage Rates ($/Dth/Month)** | | | |
| Core Firm Storage | 19.4% | | |
| Firm Storage (Other than Core) | 37.4% | | |
| **Local Transmission Rates ($/Dth)** | | **# of End-User Customers** | **% of On-System Volumes** |
| Core | 149.4% | 4,338,442 | 39.3% |
| Noncore | 127.6% | 1,016 | 44.3% |

## Average Residential Gas Bundled Rate and Bill




**Bill: $45.43 $50.05**

***$4.62 , 10% increase***



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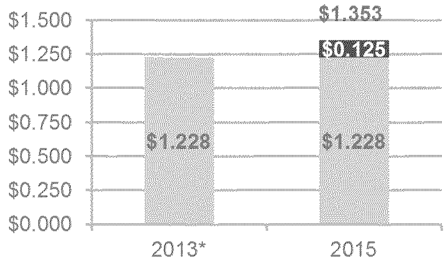
Prepared in Anticipation of Litigation
Attorney Work Product

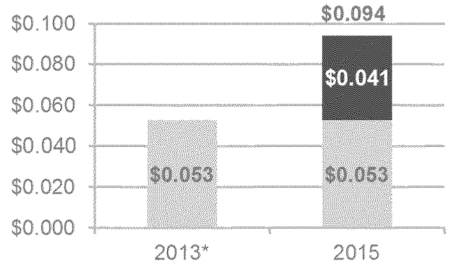
# Gas Delivery Rate Impacts
**($/Therm)**

## Residential



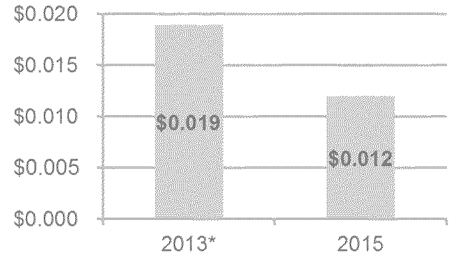

**Monthly Bill: $45.43 $50.05**
**$4.62 Increase**

## Electric Generation LT/D Service Level

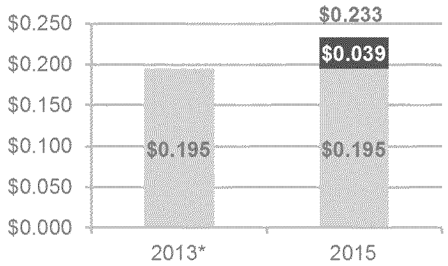



2013 Rate
GT&S Increase

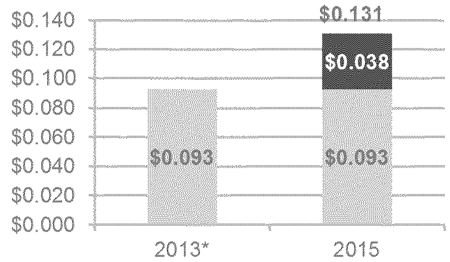
## Electric Generation Backbone Service Level**



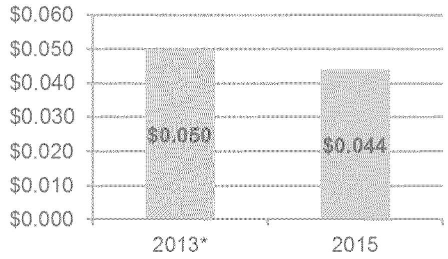

## Industrial Distribution Service Level




## Industrial Local Transmission Service Level




## Industrial Backbone Service Level**




*** 2013 rates are adjusted to reflect 2014 local transmission and fixed customer charges established in Gas Accord V.**
**** Reduction is due to expiration of a Gas Accord V Settlement surcharge paid by backbone service level customers to partially cover the cost of local transmission credits given to several Electric Generation customers and a slight reduction in 2015 fixed customer charges.**

# Large Gas Customers

| CUSTOMER NAME | Illustrative Bill Impact of 2015 | 2012 Therms on Local | 2012 Therms on Backbone |
|---|---|---|---|
| [redacted] | | | |

NOTES:
1) Customers highlighted are currently served at the Local Transmission level but receive Bill Credits that offset the Local Transmission portion of their bill (Gas Accord V Settlement). Their increase is 400% in bills

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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_023-04 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_023-Q04 | | |
| Request Date: | June 18, 2014 | Requester DR No.: | TURN-23 |
| Date Sent: | July 25, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long |

## QUESTION 4

Please provide any documents that show any analysis of the combined bill/affordability impact of the GRC request and this request that were prepared:

a. Prior to the filing of this application.

b. After the filing of this application.

## ANSWER 4

a. See PG&E's response to TURN 023, Question 03.

b. See PG&E's response to TURN 023, Question 03.

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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_023-05 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_023-Q05 | | |
| Request Date: | June 18, 2014 | Requester DR No.: | TURN-23 |
| Date Sent: | July 2, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long |

**QUESTION 5**

Provide any analysis PG&E has performed or reviewed of the bill impacts of its request on residential, non-CARE customers broken down by any or all of: customer usage levels, customer income levels, or customer geographic location.

a. For any analysis provided, please indicate whether it was reviewed prior to the filing of the application and if so, who reviewed it, when, and for what purpose.

**ANSWER 5**

a. PG&E is not aware of any documents responsive to this request.

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**Data Response**

| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_023-06 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_023-Q06 | | |
| Request Date: | June 18, 2014 | Requester DR No.: | TURN-23 |
| Date Sent: | July 2, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Ken Niemi | Requester: | Tom Long |

**QUESTION 6**

Provide any analysis PG&E has performed or reviewed of the bill impacts of its request on residential, CARE customers broken down by any or all of: customer usage levels, customer income levels, or customer geographic location.

a. For any analysis provided, please indicate whether it was reviewed prior to the filing of the application and if so, who reviewed it, when, and for what purpose.

**ANSWER 6**

a. PG&E has not performed or reviewed the requested analysis relating to CARE customers.

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**Data Response**

| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_026-01 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_026-Q01 | | |
| Request Date: | July 2, 2014 | Requester DR No.: | TURN-26 |
| Date Sent: | July 17, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long/David Berger |

## QUESTION 1

Please provide a copy of each report that Bechtel Corp. prepared for PG&E relating to the use of risk analysis to assist PG&E in managing its gas transmission and distribution assets, beginning with the report that Bechtel provided to PG&E in 1984 and continuing to the present, including the "1994 Revision" report dated May 1995.

## ANSWER 1

*Certain attachments included herewith when initially prepared were considered confidential, however, these documents are no longer considered confidential. In the interest of providing the unedited original document requested, the confidential designation has not been removed. (GasTransmissionSystemRecordsOII_DR_ LegalDivision_005-Q11_Atch01 through Atch05)*

Provided below is a summary listing of risk analysis reports from Bechtel, Inc. regarding PG&E's gas transmission and distribution pipeline replacement program from 1984 to present. The reports are provided as attachments GTS-RateCase2015_DR_TURN_ 026-Q01-Atch01 through Atch12 and GasTransmissionSystemRecordsOII_DR_Legal Division_005-Q11_Atch01 through Atch05.

| Bechtel Reports - PG&E's Pipeline Replacement Program Risk Analysis | Report Date | Attachment |
|---|---|---|
| Pipeline Replacement Program, Transmission Line Risk Analysis, Revision 0, Bechtel Petroleum, Inc. | January 1984 | GTS-RateCase2015_DR_TURN_026-Q01Atch01 |
| PG&E Gas Distribution Pipe Replacement Program, Population Density Study, Data Calculation Sheets, Revision 0, Bechtel Petroleum, Inc. | June 1984 | GTS-RateCase2015_DR_TURN_026-Q01Atch02 |
| Pipeline Replacement Program, Transmission Line Risk Analysis, Revision III, Bechtel Petroleum, Inc. * | March 1985 | GasTransmissionSystemRecordsOII_DR_ LegalDivision_005-Q11_Atch01 |
| Pipeline Replacement Program, Transmission Line Risk Analysis, Revision IIIA, Bechtel Petroleum, Inc. * | March 1985 | GasTransmissionSystemRecordsOII_DR_ LegalDivision_005-Q11_Atch02 |
| Pipeline Replacement Program, Distribution System Risk Analysis Proposal, Revision 1, Bechtel Petroleum Inc. | July 1985 | GTS-RateCase2015_DR_TURN_026-Q01Atch03 |

| | | |
|---|---|---|
| Pipeline Replacement Program, Distribution System Risk Analysis Report, Revision 0, Bechtel Inc. | August 1985 | GTS-RateCase2015_DR_TURN_026-Q01Atch04 |
| PG&E Gas Pipeline Replacement Program, Steel Gas Distribution Main Priority Analysis Report, Revision 2.0, Bechtel, Inc. | May 1986 | GTS-RateCase2015_DR_TURN_026-Q01Atch05 |
| PG&E Gas Pipeline Replacement Program, Cast Iron Gas Distribution Main Priority Analysis Report, Revision 3.0, Bechtel, Inc. | September 1986 | GTS-RateCase2015_DR_TURN_026-Q01Atch06 |
| PG&E Gas Pipeline Replacement Program, Pre-1931 Steel Gas Distribution Main Priority Analysis Report, Revision 3.0, Bechtel, Inc. | September 1986 | GTS-RateCase2015_DR_TURN_026-Q01Atch07 |
| PG&E Gas Pipeline Replacement Program, Gas Transmission Line Priority Analysis Report, Revision 5.0, Bechtel, Inc. * | September 1986 | GasTransmissionSystemRecordsOII_DR_ LegalDivision_005-Q11_Atch03 |
| PG&E Gas Pipeline Replacement Program, Population Density Study for Gas Distribution Lines, Revision 1.0, Bechtel, Inc. | February 1987 | GTS-RateCase2015_DR_TURN_026-Q01Atch08 |
| PG&E Gas Pipeline Replacement Program, Pre-1931 Steel Gas Distribution Main Priority Analysis Report, Bechtel, Inc. | September 1987 | GTS-RateCase2015_DR_TURN_026-Q01Atch09 |
| Gas Pipeline Replacement Program, Cast Iron Gas Distribution Main Priority Analysis Report, Revision 4.0, Bechtel, Inc. | September 1987 | GTS-RateCase2015_DR_TURN_026-Q01Atch10 |
| Gas Pipeline Replacement Program, Gas Distribution Main Priority Analysis Report, Bechtel, Inc. | June 1988 | GTS-RateCase2015_DR_TURN_026-Q01Atch11 |
| Gas Pipeline Replacement Program, Gas Transmission Line Priority Analysis Report, Bechtel, Inc. * | June 1988 | GasTransmissionSystemRecordsOII_DR_ LegalDivision_005-Q11_Atch04 |
| Review of the Distribution Priority Analysis (1994 Revision) for the Gas Pipeline Replacement & Rehabilitation Program, Bechtel Corporation | May 1995 | GTS-RateCase2015_DR_TURN_026-Q01Atch12 |
| Review of the Transmission Priority Analysis (1994 Revision) for the Gas Pipeline Replacement & Rehabilitation Program, Bechtel Corporation * | May 1995 | GasTransmissionSystemRecordsOII_DR_ LegalDivision_005-Q11_Atch05 |

* These reports were previously provided as attachments to the Gas Transmission System Records OII (I.11-02-016) in CPUC_005-Q11.

# PACIFIC GAS AND ELECTRIC COMPANY
## Gas Transmission and Storage Rate Case 2015
## Application 13-12-012
## Data Response

| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_026-03 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_026-Q03 | | |
| Request Date: | July 2, 2014 | Requester DR No.: | TURN-26 |
| Date Sent: | July 25, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Sara Peralta Burke | Requester: | Tom Long/David Berger |

### QUESTION 3

With respect to PG&E's testimony on p. 7-6, lines 6-12, of its Direct Testimony where PG&E states, "As reflected in the previous audit findings and self-reported non-compliances, PG&E has inadequately focused on certain aspects of corrosion control in the past. PG&E is not requesting recovery of the costs to address those deficiencies arising from past practices. PG&E expects to incur $21 million in capital and $58 million in expense through 2017 to bring its program in compliance. PG&E has excluded these costs from its forecast.":

a. Please provide a narrative explanation of how PG&E determined which costs (or types of costs) of corrosion control to exclude from its forecast and how it calculated the exclusion amounts.

b. Please provide workpapers showing the calculations supporting the $21 million capital and $58 million expense exclusion amounts.

c. Please explain why PG&E decided not to request recovery of costs to address deficiencies arising from past practices.

### ANSWER 3

a. In the third quarter of 2013, PG&E performed a review of outstanding issues that had previously been identified as potentially requiring remediation in conjunction with non-compliance issues identified in previous audits and self-reports. The outstanding issues were reviewed and compared to federal regulations to determine if deficiency in remediation constituted a non-compliance issue. During the review, funding for items that were intended to address non-compliance were excluded from PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case forecast. The number of units determined to address non-compliance were then multiplied by a unit cost to get the total of $79 million excluded from PG&E's 2015 GT&S Rate Case forecast.

b. GTS-RateCase2015_DR_TURN_026-Q03Atch01 was utilized to determine the total forecast amount excluded based on the number of units and unit cost. The list of items that were excluded can be found in GTS-RateCase2015_DR_TURN_026-Q03Atch02.

c. Based on the particular circumstances of the corrective corrosion work, PG&E believed it would be appropriate not to seek recovery of the costs to perform work to correct known areas of non-compliance with corrosion regulations.

**PACIFIC GAS AND ELECTRIC COMPANY**
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_026-04 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_026-Q04 | | |
| Request Date: | July 2, 2014 | Requester DR No.: | TURN-26 |
| Date Sent: | July 17, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long/David Berger |

**QUESTION 4**

Beginning January 1, 2010 and continuing to the present, please provide a narrative identifying each and every self-reported non-compliance issue that is not identified in response to question 2 above, and provide all documents reflecting these other self-reported non-compliance issues.

**ANSWER 4**

*Attachments 02 through 23 to this response have been marked CONFIDENTIAL and are submitted pursuant to a Non-Disclosure Agreement because they include confidential employee information.*

A summary table of every non-compliance issue self-reported by PG&E to the CPUC pursuant to ALJ 274 is included in attachment GTS-RateCase2015_DR_TURN_026-Q04Atch01. The summary table includes update letters submitted to the CPUC, but only captures self-reports related to PG&E's Gas Transmission and Storage system that were not identified in response to TURN 026, Q2. You have asked us to summarize the documents in narrative, which we have attempted to do, but please note that a review of the entire document is necessary and appropriate for accuracy.

Copies of each submitted self-report and update can be found in attachments GTS-RateCase2015_DR_TURN_026-Q04Atch02CONF through Atch23CONF.

Data Request TURN-26
ALJ-274 Self-Reported Non-Compliance Issues
December 2011 to July 2014

| Self Report # | Date Submitted | Description |
|---|---|---|
| **5** | 2/13/2012 | Discovered through annual odor intensity test at Llana Seco Ranch farm tap near Chico, fed by L-169. Leak surveys conducted and odor intensity tested along L-169. New odorizer installed. |
| **8** | 3/12/2012 | Inadequate venting of pressure relief valves discovered via Raymundo investigation. 19 stations affected. |
| **23** | 7/24/2012 | 4 covered segments (30 miles) of L-172A missed 7-year integrity reassessment scheduled for May 24, 2012. Due date was not checked when changed from ILI to ECDA. Reassessment to be completed August 31, 2012. Refresher training and more formalized procedures to be completed September 30, 2012. |
| **24** | 7/31/2012 | 8 inlet valves to HPRs tapped off of Diane Avenue DFM were underrated. Lowered pressure and replaced or eliminated valves (by October 31, 2012). |
| **25** | 8/3/2012 | Leak surveys apparently completed but 48 maps missing. PG&E standard requires retention of records/plats. Leak surveys completed August 3, 2012 with exception of SFO property. |
| **27** | 8/14/2012 | Plat D04 missed annual survey due to inadvertently excluding from aerial survey list. Completed on July 20, 2012. |
| **29** | 9/27/2012 | L-111A MAOP miscalculated based on wrong seam weld. Replacing sections to allow operation at MAOP 650 psig to be completed December 2012. |
| **30** | 10/19/2012 | Pipeline segments on L-105N,191-1, StanPac-3, and 300A are identified as high risk because of internal corrosion threats and may not have undergone integrity assessments |
| **36** | 1/4/2013 | Overpressurization on Transmission Line 210A and Line 210B near Creed Regulation Station. Caused by rainwater traveling through the conduit seal and into the feedback transmitter Valve V-33. |
| **37** | 1/15/2013 | Missed semi-annual leak survey of 1,875 feet of transmission Line 147. Plat maps 3287-G2 and 3287-H2. Class 3 location. Leak survey conducted on December 31, 2012 with no leaks found. |
| **40** | 1/30/2013 | 6 non-compliance issues (missed maintenance). Affected assets replaced and/or maintained. |
| **44** | 2/11/2013 | On October 23, 2012, a leaky valve was replaced with a valve that was fabricated with ¾" pipe pups, which are pre-welded to the valve from the factory. These pipe pups were not strength tested at the factory. As such, the valve with pups should have been pressure tested prior to installation in accordance with 49 CFR 192.507. PG&E replaced the assembly on November 5, 2012. Additionally, PG&E reviewed the valves with mislabeling and miscoding issues and determined that no other valves without a strength test and no incorrectly labeled valves had been installed. |
| **51** | 6/7/2013 | Blowdown valve V-14-F2D on DFM-0821-02 in San Jose was discovered to be inoperable on 3/10/2012. An AMC was not created because it was thought a previous AMC was still in effect. No action was taken until 3/17/2013. |

Data Request TURN-26
ALJ-274 Self-Reported Non-Compliance Issues
December 2011 to July 2014

| Self Report # | Date Submitted | Description |
|---|---|---|
| **53** | 6/13/2013 | Section of transmission pipeline not leak surveyed in 2012 because it was not included in the North Valley Transmission Leak Survey book. Last leak surveyed during pressure increase in December 2011. Corrective leak survey completed 1/18/2013, and added to 2013 Leak Survey Plan. |
| **61** | 10/15/2013 | Missed leak surveys and patrols for transmission facilities in Citrus Heights and Roseville. In October 2010, PG&E had increased the operating pressure of two DFMs from distribution pressure to transmission pressure. PG&E discovered that the changes to the DFMs had not been processed in a timely manner. Semi-annual and annual leak surveys were missed for 2011 and 2012. On September 3, 2013, PG&E conducted leak surveys of the facilities; no leaks were found. PG&E also determined that there were missed or incomplete patrols from Q1 2011 to Q1 2013. PG&E has updated the mapping information for the facilities, to ensure proper leak survey and patrol scheduling. |
| **62** | 9/6/2013 | Through PSEP QA, PG&E identified inadequate weld inspection and documentation being performed by contractor TCI on Line 114 (PSEP R-134). TCI used 2-exposure radiographic testing; inconsistent with industry practice (API 1104) and TCI's procedures to take 3 exposures. PG&E completed radiographic lab testing to confirm that the 2-exposure method can effectively identify weld defects. Also system-wide investigation of welds inspected by TCI in 2010-13, identifying 502 inadequate inspections; all have been reviewed - no safety issues. All affected pipeline sections were hydrotested. |
| **63** | 1/13/2014 | Inadequate odorization in Princeton, Colusa County. A number of factors contributed to these events, including supply variability from the Compressor Stations and the ISP, maximum heating value limits for the Chico area, and reduced pressure conditions on L-167. |
| **51.1** | 1/27/2014 (update) | Update to 7/7/2013 self-report (#51). PG&E initiated a system wide review of valve maintenance records in all Districts and Divisions. This update included the results of the review from Tracy District and East Bay Division. Five backbone transmission emergency valves and eight distribution or local transmission emergency valves were reported as inoperable and exceeded the required maintenance cycle per PG&E's WP-4430-04 and GIB 4430B-001. Five backbone transmission emergency valves and one distribution valve have been repaired or replaced and are currently back in compliance. The seven remaining distribution valves are being tracked in CAP for repair or replacement and currently have an Alternate Means of Control while the work is being implemented. PG&E will continue the system-wide review of the remaining 10 Districts and 17 Divisions and will provide a subsequent update on the results by the end of 2nd Quarter 2014. |
| **67** | 4/14/2014 | A "tap" off Line 132 on Quarry Road, Brisbane has been found to be serving a large volume customer at high pressure (128 psig). This tap was initially thought to be a service line (farm tap). As such, leak surveys and patrols were not completed at the proper frequency. Additionally, the upstream regulator was not properly maintained as a transmission regulator station. |

Data Request TURN-26
ALJ-274 Self-Reported Non-Compliance Issues
December 2011 to July 2014

| Self Report # | Date Submitted | Description |
|---|---|---|
| **69** | 5/15/2014 | PG&E has been incorrectly operating and maintaining segment 104 (838 feet in length) of Distribution Feeder Main (DFM) 3012-01 as distribution pipe instead of transmission pipe. This 12-inch pipeline is fed off of transmission Line 191 in Pittsburg. Geographic Information System (GIS) incorrectly listed the wall thickness of segment 104 as 0.281 inches and indicated the segment was distribution pipe. Upon further research it as determined that the actual wall thickness is 0.219 inches. With this change in wall thickness, the hoop stress for this segment of pipe changes the percent Specified Minimum Yield Strength (SMYS) from less than 20% to greater than 20%. Per 49 CFR §192.3, pipelines operating at 20% or more of SMYS are defined as transmission pipelines. |
| **72** | 6/12/2014 | Gas transmission pipeline facilities not properly disconnected in Kern County.<br>On May 20, 2014, while exploring design options to serve a new large industrial customer from an existing tap off of transmission line L-300B, it was determined that the PG&E tap station facilities had not been properly disconnected. These facilities had fed a large industrial customer that terminated service in the early 1990s, and originally consisted of aboveground piping, valves, a large orifice meter, and pressure regulating equipment. PG&E had removed the meter and adjacent piping in the center of the tap station sometime after the discontinuance of service.1<br>While the tap valve directly off of L-300B has been maintained annually per 49 CFR §192.745 and PG&E Utility Procedure TD-4430P-04 (Gas Valve Maintenance), approximately 30 feet of piping and another valve continued to be connected to the L-300B tap without being maintained. In addition, while disconnected from the L-300B tap piping, PG&E's pressure regulating equipment and adjacent piping continued to be pressurized with gas from the former customer's piping system. The former customer's piping continues to be pressurized with natural gas from a different source.<br>This is a violation of §192.727(c), which states, "Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard." |

Data Request TURN-26
ALJ-274 Self-Reported Non-Compliance Issues
December 2011 to July 2014

| Self Report # | Date Submitted | Description |
|---|---|---|
| **51.2** | 7/1/2014 (update) | In its January 27, 2014 update, PG&E provided the results of its analysis of valve maintenance records in the East Bay Division and Tracy District, and committed to completing a system-wide review of the emergency valves maintained by the remaining 17 divisions and 10 transmission districts.<br>PG&E has completed this system-wide review, identifying a total of 15 distribution valves, 6 local transmission valves, and 25 backbone transmission valves that had been reported as inoperable and had exceeded the required annual maintenance cycle per PG&E's Utility Procedure WP-4430-04 "Gas Valve Maintenance Requirements and Procedures", and Gas Information Bulletin (GIB) 4430B-001, "Establishing Alternate Means of Control (AMC) for Inoperable Valves" (see Attachments 1 and 2). These 46 valves include the 13 valves reported as preliminary findings in PG&E's January 27, 2014 notification.<br>PG&E is evaluating the incomplete valve maintenance and corrective work process in both the divisions and districts. Based on the results of the evaluation, PG&E will develop appropriate corrective actions to address the issues on a longer term and system-wide basis. |

**PACIFIC GAS AND ELECTRIC COMPANY**
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_027-01 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_027-Q01 | | |
| Request Date: | July 7, 2014 | Requester DR No.: | TURN-27 |
| Date Sent: | July 18, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Ken Niemi | Requester: | Tom Long/David Berger |

**QUESTION 1**

Please provide a bill impact analysis that, for each year from 2014 through 2017, combines the impact of PG&E's request in each of the three years of this application and PG&E's request in each of the three years of the 2014 GRC application on:

a. Residential bundled service customers
b. Residential transportation only customers
c. Small commercial bundled service customers
d. Small commercial transportation only customers

**ANSWER 1**

The Table below includes an illustrative bill impact analysis as requested in subparts a, b, c, and d of this question on an annual basis. The % change in 2015 includes the impact of both implementation of the 2014 GRC PD and PG&E's 2015 GT&S Rate Case request. The details of the two distinct impacts of the GRC per the PD (illustratively implemented in rates on September 1, 2014) and January 1, 2015 changes are provided in Attachment "GTS-2015RateCase_TURN_DR_027-Q01Atch01". This analysis is based on illustrative non-CARE rates.[1]

[1] CARE gas customers receive a 20% discount on gas transportation and procurement and are exempt from CARE surcharges.

| | 2014 Present | 2015 | % Change | 2016 | % Change | 2017 | % Change |
|---|---|---|---|---|---|---|---|
| RESIDENTIAL INDIVIDUALLY METERED, BUNDLED | $42.98 | $52.37 | 21.9% | $53.63 | 2.4% | $53.07 | -1.0% |
| RES INDIVIDUALLY METERED, TRANSPORT-ONLY | $60.14 | $81.55 | 35.6% | $85.07 | 4.3% | $83.56 | -1.8% |
| SMALL COMMERCIAL, BUNDLED | $182.10 | $225.67 | 23.9% | $234.30 | 3.8% | $242.97 | 3.7% |
| SMALL COMMERCIAL, TRANSPORT-ONLY | $274.36 | $388.52 | 41.6% | $414.58 | 6.7% | $438.88 | 5.9% |

Assumptions of Analysis:

- 2014 Rates
    - Present rates (2014) are based on rates effective April 1, 2014, Advice Letter 3464-G filed with and approved by the Energy Division.

- 2015 Rates
    - Revenue requirement is illustratively based on 2014 GRC in accordance with the Proposed 2014 GRC Decision (issued in June 2014 with final decision pending from California Public Utilities Commission).

    - 2-year amortization of the anticipated and illustrative GRC revenue shortfall due to a delayed i 2014 GRC Decision, i.e., 50% of the shortfall is recovered in 2015 rates and the other 50% is recovered in 2016 rates. Illustratively assumes implementation of the 2014 GRC Decision in September 2014 to calculate GRC revenue shortfall.

    - Full recovery, effective January 1, 2015, of revenue requirement requested by PG&E in its 2015 GT&S Rate Case application rates.

    - Current 2014 transportation balancing account balances are kept constant during the 2015 through 2017 period except for Core Fixed Cost Account

(CFCA) and Noncore Cost Account (NCA) to account for the effect of the recovery of the illustrative GRC revenue shortfall.[2]

- Discontinued PSEP rates January 1, 2015.
- Return of the forecasted PSEP Balance overcollection (based on PG&E's PSEP Update revenue recovery request) over one year in 2015 rates.
- Incorporates 2014 GRC PD 2015 Attrition

- 2016 Rates
  - Incorporates 2014 GRC PD 2016 Attrition and remaining 50% of 2014 GRC shortfall.
  - Incorporates PG&E 2015 GT&S Rate Case proposed 2016 Attrition.
  - Non-GRC and GT&S-related forecasted changes to rates (e.g., transportation balancing accounts, gas procurement rates) are frozen at forecast 2015 levels in order to isolate the illustrative bill impact of PG&E's 2014 GRC and 2015 GT&S Rate case applications.
- 2017 Rates
  - Removes from rates the remaining 50% of the 2014 GRC Revenue Shortfall in 2016 rates.
  - Incorporates PG&E 2015 GT&S Rate Case proposed 2017 Attrition.
  - Non-GRC and GT&S-related forecasted changes to rates (e.g., transportation balancing accounts, gas procurement rates) are frozen at forecast 2015 levels in order to isolate the illustrative bill impact of PG&E's 2014 GRC and 2015 GT&S Rate case applications.
- General
  - Average monthly usage for each of the categories specified in subparts a, b, c, and d according to the gas demand forecast and the customer billing forecast proposed in PG&E's 2015 GT&S application.
  - The Average monthly usage is then multiplied by the class' respective illustrative non-CARE bundled rate.

[2] This is done to isolate the impact of the GRC and GT&S rate cases effect. It should be noted that in January 1, 2015 the amounts in the balancing accounts will be updated due to factors other than the GRC shortfall such as the over or under collection due to the variation in actual temperatures compared to forecast. Therefore, rates will change accordingly.

# PACIFIC GAS AND ELECTRIC COMPANY
## Gas Transmission and Storage Rate Case 2015
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_027-02 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_027-Q02 | | |
| Request Date: | July 7, 2014 | Requester DR No.: | TURN-27 |
| Date Sent: | July 16, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Ken Niemi | Requester: | Tom Long/David Berger |

**QUESTION 2**

To enable the calculation of bill impacts of PG&E's request in this case on a monthly (or at least seasonal) basis:

a. Rather than the annual usage data on which the summary tables in TURN 23-2.d are based, please provide monthly usage data for residential CARE and non-CARE and small commercial CARE and non-CARE customers. Specifically:

   i. If PG&E has prepared monthly usage forecasts for 2015, 2016 and 2017, please provide those forecasts, calculated on a per customer basis, and all supporting calculations to derive those forecasts.

   ii. If PG&E has not prepared such forecast, please provide recorded month-by- month usage data, calculated on a per customer basis, for the period January 2009 through December 2013, along with an explanation of how the per customer usage numbers were derived.

b. Please feel to contact TURN if you have questions about the information TURN is seeking in this data request.

**ANSWER 2**

a.

   i. PG&E did not prepare monthly usage forecasts for residential CARE and non-Care, and small commercial CARE and non-Care customers segments. For class information by month please see Chapter 14 PG&E's proposed monthly forecasts at the bundled and transport-only levels in tabs: "Gas Demand Forecast" and "Customer Billing Forecast" in Attachment "GTS-RateCase2015_DR_TURN_027-Q02Atch01"

   ii. Please see tab: "Usage Per Customer "in Attachment "GTS-RateCase2015_DR_TURN_027-Q02Atch01" for recorded monthly information. For each of the Residential and Small Commercial classes, the following methodology was applied :

      - Combine Bundled and Transport only (volumes and number of customers).
      - Determine the total the volumes used by CARE customers.
      - Determine the total number of CARE customers.

- Determine the total volumes used by non-CARE customers.
- Determine the total number of non-CARE customers.
- Calculate the usage per customer for CARE and non-CARE customers, respectively.

b. N/A

**PACIFIC GAS AND ELECTRIC COMPANY**
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_030-02 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_030-Q02 | | |
| Request Date: | July 28, 2014 | Requester DR No.: | TURN-30 |
| Date Sent: | July 31, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Bennie Barnes | Requester: | Tom Long/David Berger |

**QUESTION 2 CORRECTED**

With respect to Table 4A-12 on p. 4A-43 of PG&E's direct testimony:

a. Please revise the installation periods in lines 2 and 3, and then revise the corresponding miles and percentages based on the changed installation period dates, as follows:

   i. Change the line 2 installation period to January 1, 1956 – June 30, 1961. If PG&E does not have month/day/year data regarding installation date, then change the line 2 installation period to 1956 – 1960.

   ii. Change the line 3 installation period to July 1, 1961 – present. If PG&E does not have month/day/year data regarding installation date, then change the line 3 installation period to 1961 – present.

b. Please provide PG&E's best and most detailed estimate of the expenses and capital costs to hydrotest all miles listed in Lines 2 and 3, as revised in response to 2.a. Please provide an explanation of how PG&E developed this estimate, including workpapers showing any calculations.

**ANSWER 2**

The updated table is provided below. Please note that the cost estimate for each line item is the un-escalated unit costs (expense only) derived in the workpapers supporting Chapter 4 for the Hydrostatic Testing program. Capital costs remain unchanged as they are for total amount of work performed and not subject to vintage of pipe.

Also note that the information on install dates is pulled from the same source that derived the original test lists (GIS 2.0) and is subject to change upon review of the updated PFLs when the projects are engineered.

| | Miles | Percentage | Expense Costs |
|---|---|---|---|
| Pre-1956 or IM tests | 315 | 61.8% | $ 305,550,000 |
| Jan 1, 1956 - June 30, 1961 | 98 | 19.2% | $ 95,060,000 |
| July 1, 1961 - Present | 97 | 19.0% | $ 94,090,000 |
| Totals | **510** | **100.0%** | **$ 494,700,000** |

**PACIFIC GAS AND ELECTRIC COMPANY**
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_031-01 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_031-Q01 | | |
| Request Date: | July 11, 2014 | Requester DR No.: | TURN-31 |
| Date Sent: | July 25, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | Sumeet Singh | Requester: | Tom Long/David Berger |

**QUESTION 1**

Please provide a chart showing mileage of all 6,750 miles of PG&E transmission pipe (per PG&E Direct Testimony, p. 4-3) broken down by the following categories: Class 1 HCA, Class 1 non-HCA, Class 2 HCA, Class 2 non-HCA, Class 3 HCA, Class 3 non-HCA, Class 4 HCA, Class 4 non-HCA.

**ANSWER 1**

The analysis of the approximately 920 miles that will be included in PG&E's total transmission mileage of approximately 6,750 as a result of the transmission definition change is not yet complete. Therefore, PG&E cannot provide a breakdown of those approximately 920 miles.

For the remaining transmission mileage in PG&E's system, please refer to Part Q of the 2013 Pipeline and Hazardous Materials Safety Administration (PHMSA) 7100 Report for PG&E and Standard Pacific (StanPac). Please see PG&E's response to IndicatedProducers_002-Q042 for the PG&E and StanPac 7100 reports identified as GTS-RateCase2015_DR_IndicatedProducers_002-Q042Atch01 and GTS-RateCase2015_DR_ IndicatedProducers_002-Q042Atch02, respectively.

# PACIFIC GAS AND ELECTRIC COMPANY
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| | | | |
|---|---|---|---|
| PG&E Data Request No.: | TURN_031-02 | | |
| PG&E File Name: | GTS-RateCase2015_DR_TURN_031-Q02 | | |
| Request Date: | July 11, 2014 | Requester DR No.: | TURN-31 |
| Date Sent: | July 21, 2014 | Requesting Party: | The Utility Reform Network |
| PG&E Witness: | | Requester: | Tom Long/David Berger |

### QUESTION 2

In preparing and presenting PG&E's request in the prior GT&S case (A.09-09-013), was safety PG&E's highest priority? (Please provide a yes or no answer prior to providing any explanation for the answer.) If not, what was PG&E's highest priority?

### ANSWER 2

Yes, safety has always been PG&E's top priority. However, expectations and requirements regarding safety have increased significantly since the 2011 Gas Transmission and Storage (GT&S) case (A.09-09-013), as have expectations for how asset and risk management are performed. PG&E's current 2015 GT&S filing seeks to respond to and address these new expectations and requirements.