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

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

August 31, 2012

GA2011-35

Ms. Jane Yura, Vice President
Gas Operations, Standards and Policies
Pacific Gas and Electric Company
P.O. Box 770000, Mailcode N15F
San Francisco, CA 94177

Re: April 2011 Risk Assessment Audit

Dear Ms. Yura:

Please find attached the results of the risk assessment audit of Pacific Gas and Electric Company's (PG&E) Integrity Management Program conducted April 5-8, 2011, by staff from the Consumer Protection and Safety Division (CPSD), of the California Public Utilities Commission (Commission). Representatives from CPSD management and the Pipeline and Hazardous Materials Safety Administration (PHMSA) also participated in the audit.

Please review the findings of CPSD's audit in the Summary of Risk Assessment Audit attached to this letter. Within 30 days of your receipt of this letter, please provide a written response indicating measures taken by PG&E to address the audit findings and concerns noted in the summary. If you have any questions regarding the audit letter, please contact Paul Penney at 415-703-1817.

Sincerely,

Mich Roberts

Michael Robertson, P.E.
Program Manager
Gas Safety and Reliability Branch
California Public Utilities Commission

Enclosure: Summary of Inspection Findings
(A) CPSD Audit Findings
(B) CPSD Audit Concerns
(C) CPSD Audit Comments

cc: Larry Deniston, PG&E
Larry Berg, PG&E
Frances Yee, PG&E
Karen Roth, PG&E
Zach Barrett, PHMSA

SUMMARY OF RISK ASSESSMENT AUDIT

I. CPSD Audit Findings

a. <u>Audit Findings Identified in Protocol C.01.a iv and xi:</u>

Integrity Management Inspection Protocols C.01.a.iv and xi state:

"If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]...

iv. Manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4) and ASME B31.8S-2004, Appendix A4.3]...

xi. All other potential threats"

Title 49 Code of Federal Regulations (49 CFR), §192.917(e)(3) states:

"(3) Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase"

Pursuant to 49 CFR §192.917(e)(3), pipeline operators are required to analyze the threat of manufacturing defects in all longitudinal seams, including Double Submerged Arc Welded (DSAW) and other seams with joint factor of 1.0 in each High Consequence Area (HCA). PG&E's Risk Management Program (RMP)-06[1] under "Manufacturing Threat" only considers manufacturing defects to exist for seams with a joint efficiency factor of less than 1.0, Low Frequency Electric Resistance Welded (ERW), or Flash Welded Pipe, or pipe installed before 1970 that may have one of these types of seams. PG&E must amend its procedures to give consideration to all seams susceptible to manufacturing defects; therefore, PG&E is in violation 49 CFR §192.917(e)(3).

PG&E references "Data Sources" specifically relating to manufacturing and construction threats; external data sources include, but are not limited to John F. Kiefner's, "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines", Final Report No. 05-12R,

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1 RMP-06, Rev. 6, Section 3.5, pg. 29

April 26, 2007.[2] This report identifies DSAW as one of the weld types that has manufacturing defects.[3]

49 CFR §192.917(e)(4) states in part:

"If an HCA contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and... operating pressure on the segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies..." [Emphasis Added]

49 CFR §192.917(e)(4) states these seams can be considered stable unless the Maximum Operating Pressure (MOP) experienced during the preceding five years is exceeded. PG&E's RMI-06[4], Revision 1, stated that PG&E would consider these seams as stable unless the MOP + 10 percent is exceeded. The regulations do not define or allow for any increase, by 10 percent or any other value to be considered in determining seam stability. Revision 1 of RMI-06 improperly included up to an additional 10 percent; therefore, PG&E was in violation of 49 CFR §192.917(e)(4). However, PG&E has now revised RMI-06 to consider any increase over the MOP, and not by pressures up to 10 percent over the MOP.

During the audit, CPSD requested PG&E provide data for pipeline segments where potential manufacturing and construction defects (including seam defects) were identified because the operating pressure exceeded the MOP. In compliance with this request, PG&E provided CPSD with data on 83.73 miles of pipeline (see Table) where the manufacturing and construction defect threat was identified, and also provided a report by Kiefner and Associates analyzing this data.

Summary of the Manufacturing and Construction Defect Evaluation[5]

Pipe segments considered in this analysis.	83.73 miles
Segments determined to have not experienced a pressure increase after further review.	18.15 miles
Segments where manufacturing and construction defects are considered stable regarding pressure increases or not applicable.	62.65 miles
Segments requiring further review to determine the stability of manufacturing and construction defects.	2.92 miles

The report identified 83.73 miles of pipeline that was analyzed. The analysis in the report determined that for 62.65 miles manufacturing defects were considered stable based on the hydrostatic mill pressure test or if the operating pressure was part of a low stress segment.[6] As noted in the report, the analysis did not consider any interacting threats.[7] Also the report did not consider any defect growth subsequent to the mill hydro-test that may have occurred during transport or construction of these pipeline segments. While Kiefner and Associates performed an Engineering Critical Assessment (ECA) on the 83.73 miles of pipeline, and 62.65 miles were determined stable, 49 CFR §§192.917(e)(3) and 192.917(e)(4) are clear in requiring that PG&E

2 RMP-06, Rev. 6, Section 2.4, pg. 21

3 Pg. 4 of Kiefner's report and Table A1

4 RMI-06, Rev. 1, Section 1.0, pg. 2

5 The table is reproduced from Table 1, page 2 of Kiefner and Associates report (0215-1108 Final Report)

6 Defined on page 2 of the report as an operating stress level <20% Specified Minimum Yield Strength (SMYS). Per 49 CFR 192.3, any pipeline operating at >20% SMYS is considered a transmission line.

7 See pg. 2 of the report.

prioritize these segments as high risk segments for the baseline assessment or subsequent reassessments if the MOP has increased above the MOP experienced during the five years preceding identification of the HCA. Also, an assessment method capable of assessing seam integrity must be used. Therefore, PG&E is in violation of 49 CFR §§192.917(e)(3) and 192.917(e)(4).

CPSD staff also has a number of follow-up questions and requests regarding these identified segments.

1) For the 62.65 miles of pipeline identified as being stable in Table 1, please provide an updated summary table of pipeline segments, and the miles associated with these segments that have already been hydro-tested, pipeline segments, and the miles associated with these segments still scheduled for a hydrostatic pressure test or replacement[8] and segments, and related miles of pipeline determined to be non-transmission. In addition to this summary table, please provide hydrotest data for each segment already tested, or if data has already been provided to CPSD, please reference the data in your response. The data should include all failures to hold pressure, including any failures due to manufacturing and/or construction defects and a description of any interacting threats that contributed to the failures.
2) For all pipeline segments from the 62.65 miles yet to be hydrotested, please provide an update after hydrostatic testing, identifying all failures, including any failures to hold pressure that were a result of manufacturing or construction defects. Also, if any interacting threats contributed to the failures, please identify them as well. As ongoing hydrotest data is provided to CPSD, please include and flag the segments that were included in the 62.65 miles.
3) For the 2.92 miles of pipe identified as requiring further review (as of the date of the Kiefner report), PG&E has provided an update of the current status for each segment that comprises the 2.92 miles.[9] For each of the segments that have had a seam assessment, or will have a seam assessment in 2012 or 2013, please provide the results of hydrostatic testing, identifying all failures, including any pipe failures that result from manufacturing or construction defects. Also, if any interacting threats contributed to the failures, please identify them as well. Please provide a report at the conclusion of testing each segment that comprises the 2.92 miles. The report can be included with ongoing hydrotest data provided to CPSD, but please flag the segments that were included in the 2.92 miles.

Hard Spots

CPSD staff disagrees that hard spots are not a recognized threat in 49 CFR, Subpart O, since they can clearly be introduced during the manufacturing process and are therefore a manufacturing threat; see the "Integrity Characteristics of Vintage Pipelines" report, pg. 20 for details on how hard spots can be formed during the manufacturing process. CPSD staff also disagrees that the assessment and mitigation of this threat is not necessary to declare a pipeline's integrity assessment complete.

If a particular type of pipe from a manufacturer has a history of hard spot failures (i.e., from reference materials such as the "Integrity Characteristics of Vintage Pipelines" report or a failure history due to hard spots for a particular type of pipe in PG&E's system), then data should demonstrate that conditions are not present on a pipeline segment that would cause the hard spot to become potentially unstable. As noted in the referenced "Integrity Characteristics of Vintage

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8 Hydro-testing is required by the Commission order regarding testing or replacement of transmission pipe with no hydrostatic test records. The order is part of R. 11-02-019 and was approved by the Commission on June 9, 2011.

9 The update was provided in data request GT-Matters_DR_Commission_294-Q01Atch01.

Pipelines" report, certain conditions are necessary to cause a hard spot to potentially become unstable. First, the coating must be damaged at the location of the hard spot. Second, cathodic protection potentials less than (more negative than) -1.2 volts must be present to allow hydrogen to form at the coating holiday. It should be noted that PG&E should have a full history of cathodic protection for the pipe segments in question; a history of unknown cathodic protection potentials means PG&E should assume excessive potentials. Third, stress levels in excess of 60% SMYS increases the likelihood of cracking. Fourth, Rockwell hardness above C39 makes hydrogen stress cracking more probable. Thus, a review of the applicable data should be conducted for segments containing pipe from a manufacturer that has a known history of hard spots.

PG&E's procedures in RMP-05 and RMP-06 reference the hard spot threat, but these procedures are inadequate in addressing this threat. RMP-05, Rev 5, assigns 100 risk points in the "C) Material Flaws or Unique Joints" category based on mill and age. RMP-06, Rev 6 (pg. 32) also indicates that hard spots are assumed to exist for certain manufacturers during certain years of production when the pipe segment operates at a pressure of greater than 50% SMYS; however, the only actions indicated in RMP-06 are to manage the threat by limiting the cathodic protection potentials to greater than (less negative than) -1.2 volts. The "Integrity Characteristics of Vintage Pipelines" report discusses on page 22 the steps needed to identify the possibility for hard spots to become potentially unstable. By limiting cathodic protection potentials to greater than -1.2 volts as its only action, PG&E is essentially assuming that the hard spots are stable without a review of cathodic protection history and coating conditions, which may identify potentially unstable hard spots and the need to assess the segment for this threat.

PG&E should incorporate the steps necessary to evaluate the potential for hard spot threats from the "Integrity Characteristics of Vintage Pipelines" report into one of PG&E's RMPs, and if there is an increased potential threat because all the applicable factors are present (i.e., poor coating, increased cathodic protection levels, Rockwell hardness, etc.), PG&E must assess the pipe segments and mitigate hard spots where all the applicable conditions are found (See Figure 13, page 22 of the "Integrity Characteristics of Vintage Pipelines" report).

b. Audit Findings Identified in Protocol C.01.a vi and viii:

Integrity Management Inspection Protocols C.01.a.vi and C.01.a.viii state in part:

"If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]...

vi. Equipment failures...

viii. Incorrect operations (including human error)..."

49 CFR §192.917(a) states in part:

"Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference see §192.7..."

The threat algorithm in RMP-01 does not include factors for "Incorrect Operations" (including human error) and the "Equipment failure"[10] threats. PG&E assumes Incorrect Operations and

10 ASME B31.8S-2004, Section A6.1, pg. 49; Equipment is defined as "...pipeline facilities other than pipe and pipe components."

Equipment failure threats to exist for all HCAs in the entire system.[11] Regardless of what PG&E believes, it must include separate factors for both of these threats in the risk ranking algorithm that differentiates risk, as appropriate, for each line segment and incorporates the data elements identified in A6.2 and A8.2.[12]

PG&E indicated in its response to the May 2010 Integrity Management audit conducted by CPSD, that the equipment threat is managed through its existing Operations and Maintenance (O&M) procedures, including: (1) Documenting and tracking material problems and failures through its Material Problem Reporting (MPR) system, and (2) Documenting key system events in the system event reporting log. Although PG&E is managing this threat through the O&M procedures, including mitigating equipment problems and failures, PG&E still needs to include this threat in its risk algorithm. The flowchart in ASME B31.8S-2004, Figure A.6 identifies actions to manage the threat as one part of a larger process that includes a risk assessment. Therefore, PG&E is in violation of 49 CFR §192.917(a) for not including this threat (listed in ASME B31.8S-2004, Section 2.2).

c. Audit Findings Identified in Protocol C.01.a x:

Integrity Management Inspection Protocol C.01.a.x states in part:

"If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]...

x. Cyclic fatigue or other loading condition [§192.917(e)(2)]..."

49 CFR §192.917(e)(2) states:

"(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat...

(2) Cyclic fatigue. An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment." [Emphasis Added]

PG&E does not consider cyclic fatigue to be a threat, and does not include it in its threat algorithm RMP-01. PG&E's protocol matrix references the Kiefner[13] report for justifying the exclusion of cyclic fatigue. This report analyzes cyclic fatigue as it relates to pressure cycling in pipelines. 49 CFR §192.917(e)(2) does not restrict cyclic fatigue to only pressure induced cyclic fatigue. Transmission pipelines may be subject to other cyclic loading conditions in addition to the pressure cycling included in the Kiefner report. PG&E does include consideration of external forces on the pipeline in RMP-04, which is an algorithm that incorporates forces due to crossings (seismic and water), unstable soil, seismic area and erosion.

There are a number of assumptions used in the Kiefner report to estimate the expected life of a

11 RMP-06, Rev. 6, pg. 31

12 ASME B31.8S: Appendices A6 and A8, pages. 49 and 52 respectively

13 "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines"

pipeline segment due to pressure induced cyclic fatigue, including defect geometry, test pressure (if applicable) and the magnitude and frequency of pressure cycling.[14] PG&E must justify the exclusion of pressure induced cyclic fatigue as a threat for each line segment based on a calculation of the expected life of the segment given test pressure (if any), frequency and magnitude of pressure cycling, and any other factors that may need to be considered, including an assumption of defects in the segment that could be exacerbated by cyclic fatigue per 49 CFR §192.917(e)(2). As noted in the INGAA/ Kiefner report, *"Since it is relatively easy to calculate the relative aggressiveness of a given pressure spectrum, an operator should be readily able to establish the expected minimum time to failure for a given segment."*[15]

PG&E is in violation of 49 CFR §§192.917(e) and 192.917(e)(2) for not including cyclic fatigue in its threat analysis and evaluating whether it would necessitate accelerating assessments. PG&E must also consider and include how cyclic fatigue can affect other threats on some or all of the pipeline segments and if such interactive threats may require a change in assessment method along with accelerating assessments.

d. Audits Findings Identified in Protocol C.01.c:

Integrity Management Inspection Protocol C.01.c states:

"Verify that the operator's threat identification has considered interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) [ASME B31.8S-2004, Section 2.2]."

49 CFR §192.917(a) requires a pipeline operator to evaluate all potential threats to each covered pipeline segment. Potential threats include, but are not limited to, the threats listed in ASME B31.8S-2004, Section 2. Subsection 2.2 requires the interactive nature of threats (i.e., more than one threat occurring on a segment of pipe at the same time) to also be considered.

PG&E makes reference to interactive threats in RMP-06[16] and as discussed below, references interactive threats in regard to the seam stability issues. However, PG&E does not provide further guidance in RMP-06 as to other interactive threats to consider such as hard spots and excessive corrosion potentials, earth movement and seam and/or girth weld issues, etc., and those that may be most common.

The PG&E Criteria for Seam Stability Analysis[17] mentions a seam will be considered unstable under (iii) *"...or other interacting threats..."* This could be stated clearer if the intent is that any interactive threat present on a seam is to be considered unstable (such as selective seam corrosion).[18]

e. Audit Findings Identified in Protocol C.01.d:

Integrity Management Inspection Protocol C.01.d states:

"Verify that the approach incorporates appropriate criteria for eliminating a specific threat for a particular pipeline segment. [ASME B31.8S-2004, Section 5.10]"

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14 See "Evaluation of the Stability of Manufacturing and Construction Defects on Natural Gas Pipelines" (final report 05-12R, April 2007), Table 6, pg. 28

15 "Evaluation of the Stability of Manufacturing and Construction Defects on Natural Gas Pipelines" (final report 05-12R, April 2007), pg. 25

16 RMP-06, Rev. 6, Section 2.3, pg. 19

17 RMP-06, Rev. 6, Section 3.5, Table, pg. 30

18 ASME B31.8S-2004, Section 2.2, pg. 5

The threats PG&E inappropriately eliminates in its threat analysis are:

1) Equipment Failures: PG&E indicates that this threat is assumed to exist in all HCAs, and is managed through its O&M procedures. As a result, PG&E does not include the threats from specific equipment in its threat analysis or risk ranking algorithm. However, PG&E needs to incorporate appropriate criteria for elimination of the threat from consideration on a segment by segment basis.

2) Incorrect Operations: PG&E indicates that the incorrect operations threat is assumed to exist for all HCAs.[19] As a result, PG&E does not include the threats from specific operations in its threat analysis or risk ranking algorithm. However, PG&E needs to incorporate appropriate criteria for elimination of the threat from consideration on a segment by segment basis.

3) Cyclic Fatigue: PG&E makes a blanket exclusion of this threat and does not include appropriate criteria for elimination of this threat as explained in the Integrity Management Inspection Protocol C.01.a.

PG&E is in violation of 49 CFR §192.917(c) for not including threats listed in ASME B31.8S-2004, Section 5.10 (incorporated by reference).

f. Audit Findings Identified in Protocol C.02.a:

Integrity Management Inspection Protocol C.02.a states:

"Verify that the operator has in place a comprehensive plan for collecting, reviewing, and analyzing the data. [ASME B31.8S-2004, Section 4.2 and ASME B31.8S-2004, Section 4.4]"

49 CFR §192.917(b) states:

(b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline." [Emphasis Added]

In RMP-06, under Data Elements Selected for Initial Analysis, PG&E states: "…the company has chosen pipeline attributes based upon available, verifiable information, or information that can be obtained in a timely manner."[20] [Emphasis Added] As a result, PG&E may not be conducting pre-assessments based on all available information. Some information may be excluded that was not obtained in a timely manner. In addition, PG&E does not define what it considers a timely manner. Therefore, PG&E is in violation of 49 CFR §192.917(b).

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19 RMP-06, Rev. 6, Section 3.5, pg. 31

20 RMP-06, Rev. 6, Section 2.4, pg. 23

g. Audit Findings Identified in Protocol C.02.b:

Integrity Management Inspection Protocol C.02.b states:

"Verify that the operator has assembled data sets for threat identification and risk assessment according to the requirements in ASME B31.8S-2004, Section 4.2, ASME B31.8S-2004, Section 4.3, and ASME B31.8S-2004, Section 4.4. At a minimum, an operator must gather and evaluate the set of data specified in ASME B31.8S-2004, Appendix A (summarized in ASME B31.8S-2004, Table 1) and consider the following on covered segments and similar non-covered segments [§192.917(b)]:

1. Past incident history
2. Corrosion control records
3. Continuing surveillance records
4. Patrolling records
5. Maintenance history
6. Internal inspection records
7. All other conditions specific to each pipeline."

In RMP-05 (Design/Materials Threat Algorithm) under "Design/Materials Leak Rate" it states:[21]

"Leaks within the last twenty years on a pipe segment or on adjacent segments with the same pipe properties and installed job or project number within a one mile radius of the leak."

49 CFR §192.917(b) requires that an operator gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. PG&E restricts leak data to only leaks that occur within one mile of the pipeline segment. Therefore, PG&E is in violation of 49 CFR §192.917(b) for not considering leak data for both covered and similar non-covered segments from the entire pipeline.

The procedure in RMP-06 for identifying data sources for the risk model lists "typical" sources.[22] PG&E should identify the specific sources of data it uses in the risk model.

h. Audit Findings Identified in Protocol C.02.d.i-iv:

Integrity Management Inspection Protocol C.02.d.i-iv state:

"Verify that the operator has checked the data for accuracy. If the operator lacks sufficient data or where data quality is suspect, verify that the operator has followed the requirements in ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, and ASME B31.8S-2004, Appendix A [ASME B31.8S-2004, Section 4.1, ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, ASME B31.8S-2004, Section 5.7(e), and ASME B31.8S-2004, Appendix A]:

i. Each threat covered by the missing or suspect data is assumed to apply to the segment being evaluated. The unavailability of identified data elements is not a justification for exclusion of a threat.
ii. Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority.
iii. Records are maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered.

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21 RMP-05, Rev. 5, pg. 7, Section 6.1, Item F footnote

22 RMP-06, Rev. 6, pg. 21

iv. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required."

PG&E's RMP-06, Revision 6, does not adequately address the control or verification of the quality of data used in key integrity management processes such as threat identification and risk assessment, nor does it include any reference to other documented procedures for ensuring the quality of the information. According to RMP-06, *"The quality and consistency of the data must be verified once information is collected."*[23] However, the bullets listed afterward provide a minimum amount of guidance.

PG&E is in violation of 49 §192.917(c) for not following the processes listed in ASME B31.8S-2004, Section 5.7(e).

i. <u>Audit Findings Identified in Protocol C.02.f.ii:</u>

Integrity Management Inspection Protocol C.02.f.ii states:

"Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data integration includes...

ii. Integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third party damage [§192.917(e)(1)]."

As noted in PG&E's response to the May 2010 integrity management audit conducted by CPSD, PG&E is not currently entering Underground Service Alert (USA) information into GIS and is addressing the requirements of ASME B31.8S and 49 CFR §192.917(e)(1) through other measures.

49 CFR §192.917(e)(1) states:

"... An operator <u>must</u> utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the <u>susceptibility</u> of each covered segment to the threat of third party damage... the operator must integrate data from these assessments with data related to <u>any encroachment</u> or foreign line crossing..." [Emphasis Added]

USA data is a key indicator of the potential for third-party damage and integration of this data with indications of damage discovered through the External Corrosion Direct Assessment (ECDA) process or In-Line Inspections (ILI) runs must be performed in order to better understand where third-party damage may be more of a threat. For example, small coating flaw indications discovered on a segment of pipe during the ECDA process may be the result of third-party damage. These coating indications may not be graded appropriately (i.e., monitored, scheduled or immediate) if the ECDA data is not appropriately integrated with the USA data.

PG&E's interpretation is incorrect, and is in violation of 49 CFR §192.917(e)(1). PG&E must include the USA data in GIS to determine the potential for third party damage.

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23 RMP-06, Section 2.5, pg. 23

j. Audit Findings Identified in Protocol C.03.a.i and v:

Integrity Management Inspection Protocols C.03.a.i and C.03.a.v state:

"Verify that the operator's risk assessment supports the following objectives [ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.4]…

i. Prioritization of pipelines/segments for scheduling integrity assessments and mitigating action…

v. Assessment of the use of or need for alternative inspection methodologies…"

By not incorporating all potential threats (including equipment failures and cyclic fatigue) and giving uniform consideration to the incorrect operations threat, the objective in ASME B31.8S-2004, Section 5.3, "prioritization of pipelines/segments for scheduling integrity assessments and mitigating action" could be inaccurate and not timely. Also, since PG&E does not incorporate all these threats into its risk ranking algorithm in RMP-01, the need for alternative inspection methodologies may not be identified as required in ASME B31.8S-2004, Section 5.3.

k. Audit Findings Identified in Protocol C.03.c.i:

Integrity Management Inspection Protocol C.03.c.i states:

"Verify that the risk assessment explicitly accounts for factors that could affect the likelihood of a release and for factors that could affect the consequences of potential release, and that these factors are combined in an appropriate manner to produce a risk value for each pipeline segment. [ASME B31.8S-2004, Section 3.1, ASME B31.8S-2004, Section 3.3, ASME B31.8S-2004, Section 5.2, ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.7(j)] Verify that the risk assessment approach includes the following characteristics:

i. The risk assessment approach contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk [ASME B31.8S-2004, Section 5.7(a)]..."

In addition, ASME-B31.8S, Section 5.7(g) states: "The risk assessment process shall be thoroughly and completely documented..."

CPSD reviewed PG&E's RMPs and found the following deficiencies. Please address each of the following:

1. RMP-01:

A. The Consequence of Failure (COF) algorithm consists of four factors.[24] These factors are the Impact on Population (IOP), Impact on the Environment (IOE), Impact on Reliability (IOR) and the Failure Significance Factor (FSF). The formula for assigning points to the IOP consists of three factors including the Potential Impact Radius (PIR). The formula for assigning points to the PIR in Section 6.4.1(C), is not documented or justified.

B. In Section 6.4, the Failure Significance Factor (FSF) is assigned a value of one if a gas transmission line is within 300 ft. of a hospital, school, prison or switch-

24 RMP-01, Rev 5, page 5.

yard. PG&E provides no documented justification for this criterion. These facilities could also be affected even if they are located farther than 300 ft. but still within the PIR. This index factor should be based on the PIR value or 300 ft., whichever is greater.

C. The chart in Section 7.1 does not represent a true risk profile of the pipeline. It is not possible to produce such a profile with an index model such as PG&E's model, since the index values do not correlate to a probabilistic risk value. This item is a comment and requires no response.

D. In Section 9, PG&E defines HCA Risk and provides two formulas for calculating the risk (equations 4 and 5). The two risk elements, Likelihood of failure (LOF) and COF, are defined. CPSD staff believes the COF formula is flawed. On page 17, PG&E states: "Also, because all covered pipelines are, by definition, in High Consequence Areas, it is not necessary to consider anything other than size of failure."[25] All HCAs are not equal. For example, an HCA with 100 buildings intended for human occupancy has a higher consequence potential than an HCA with only 20 buildings intended for human occupancy.

2. <u>RMP-02</u>

A. The use of the non-conservative default value in Section 6.1, item A, is not documented or justified. PG&E identifies the default value as >10,000 ohm-centimeter, which assigns the least amount of points for this factor and implies a less corrosive environment (See ASME-B31.8S, Table B1, pg. 57).

B. In Section 6.1, item H, PG&E assigns points based on high or medium voltage and with or without Cathodic Protection. PG&E should more precisely define what is meant by high and medium voltage. Also, the presence of voltage sources within 500 ft. of a pipeline segment does not necessarily imply interference currents on the pipeline. Therefore, PG&E should consider adjusting the formula to assign points for known versus unknown interference currents.

3. <u>RMP-03</u>

The third party damage (TPD) threat algorithm in RMP-03 does not include any score or consideration of one-call ticket frequency. The one-call ticket frequency is a key indicator of activity along the pipeline right-of-way and an indicator of TPD risk.

4. <u>RMP-05</u>

A. The individual factors A through G for the algorithm in RMP-05 (Design Materials Threat Algorithm) add up to 120%, effectively raising the weighting of the Design/Materials factor in the probability of failure formula in RMP-01.[26]

B. Under PG&E's A factor, it assigns a point score of 10 to DSAW pipe, but does not include any considerations for modifying this value. PG&E should take into account DSAW pipe that has a history of incidents associated with certain manufacturers. For example, DSAW pipe is listed in the "Integrity Characteristics of Vintage Pipelines" report as having pipe body incidents for certain manufacturers.[27]

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25 RMP-01, Section 9, pg. 17

26 RMP-01, Equation 2, pg. 8

27 See for example Figures F2, F4 and F5.

II. CPSD Concerns

Audit Findings Identified in Protocol C.01.a ii:

Integrity Management Inspection Protocol C.01.a.ii states in part:

"If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004, Section 2.2]

ii. internal corrosion,…"

CPSD is concerned about the justification that 98% of PG&E's gas transmission system is not subject to the Internal Corrosion (IC) threat, and therefore, has not been or will not be assessed for IC. PG&E is required to prove that a threat does not exist before IC can be discounted for any particular transmission line segment. Further, PG&E is required to assume there is a threat of IC if data is missing. ASME B31.8S-2004 states:

> *"Limited data sets shall be gathered to evaluate each threat for the prescriptive integrity management program applications. These data lists are provided in Nonmandatory Appendix A for each threat and summarized in Table 1. All the specified data elements shall be available for each threat in order to perform the risk assessment. <u>If such data are not available, it shall be assumed that the particular threat applies to the pipeline segment being evaluated.</u>"*[28] *[Emphasis Added]*

More specifically, while PG&E addresses the above requirement through RMP-06 and RMP-09, CPSD is concerned that the specific data demonstrating IC is not a threat is incomplete. PG&E provides an overview of the IC threat evaluation process in RMP-06 that includes (1) identifying those locations where IC is known to exist. This is defined as any location where there has been an internal corrosion leak or if the threat exists in the opinion of the Senior Corrosion Engineer; and (2) evaluating the IC threat for the remaining gas transmission lines is incorporated into the ECDA procedure documented in RMP-09.

Because of CPSD concerns, please provide the following:

1. A listing of all points in California where gas is injected into the gas transmission system, including all incoming transmission lines, storage points and any other sources that feed into the system. Also, identify which transmission lines these injection points feed into.
2. Maps highlighting where each of these injection points is located.
3. Maps showing all of the locations where moisture monitoring, either continuous or periodic, is being performed and the dates such monitoring commenced and the dates the input/injection locations started supplying gas to the system.
4. A current listing of all transmission lines where IC has been identified as a threat and has been assessed or will be assessed.
5. A current listing of all transmission lines that PG&E believes is not subject to the IC threat.

CPSD staff will review this information and follow up with a data request for additional information that will provide a sampling of gas transmission line documentation, justifying the exclusion of IC as a threat.

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28 ASME B31.8S-2004, Section 4.2.1, pg. 9

III. Comments

The following comment relates to other program areas that make use of risk assessments:

There is no procedural requirement for Subject Matter Experts to review risk model outputs for the specific purpose of determining Preventative and Mitigative (P&M) measures. For example, one of PG&E"s Long Term Integrity Management Plans that CPSD reviewed during the inspection had no P&M measures identified and no discussion for why P&M measures were not needed.