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October 17, 2012

Mr. Michael Robertson
Gas Safety and Reliability Branch
Consumer Protection and Safety Division
California Public Utilities Commission
320 West 4th Street, Suite 500
Los Angeles, CA 90013

Re: General Order 112-E Audit of the PG&E's Integrity Management Program

Dear Mr. Robertson:

The Consumer Protection and Safety Division of the CPUC conducted a risk assessment audit of PG&E's Integrity Management Program on April 5 - 8, 2011. The attachment to this letter provides PG&E's detailed responses to the inspection findings listed in your August 31, 2012 letter.

Please contact Larry Berg at (925) 974-4084 or LMB5@pge.com for any additional questions you may have regarding this notification.

Sincerely,

/S/

Frances Yee
Acting Director, Regulatory Compliance and Support

Attachment

cc:	Julie Halligan, CPUC	Jane Yura, PG&E
	Paul Penney, CPUC	Roland Trevino, PG&E

CPUC Letter Item #	PHMSA Protocol	Type of Finding	CPUC Finding	PG&E Response
I.a.(1)	C.01.a.iv and xi	NOV 192.917 (e)(3)	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:[§ l92.917(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 B3l.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 (DSA W) and other seams with joint factor of 1.0 in each High Consequence Area (HCA). PG&E's Risk Management Program (RMP)-06 (Rev. 6, Section 3.5, pg. 29) 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 believes it is compliant with 192.917(e). The CPSD misquotes 192.917(e)(3). It does not make reference to all longitudinal types. It states, "if an operator identifies the threat of manufacturing and construction defects (including seam defects) in a covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects." As such, PG&E does not see any conflicts with PG&E's previous threat identification procedure that would meet the criteria of a violation of 192.917(e)(3). However, as part of our continuous improvement efforts, PG&E has amended its manufacturing threat identification procedure. The update to the manufacturing threat identification process was completed on 8/14/2012, and was prior to notification by the CPUC on 8/31/12 of a potential violation. The updated manufacturing threat identification process is listed in RMP-16, "Threat Identification." This procedure identifies any of following conditions for identification of a manufacturing threat: -joint efficiency less than 1.0 -presence of low frequency welded ERW pipe or flash welded pipe -Lack of existence of a subpart J Test to 1.25x MAOP -History of a seam failure on segment or similar segment (on pipe in PG&E's transmission system). The revised procedure considers all seam types as well as non-seam manufacturing threats.

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I.a.(2)	C.01.a.iv and xi	NOV 192.917 (e)(4)	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, April 26, 2007 (2 RMP-06, Rev. 6, Section 2.4, pg. 21). This report identifies DSAW as one of the weld types that has manufacturing defects (Pg. 4 of Kiefner's report and Table A1). 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 ASMEIANSJ 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 ... " 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 (Rev. 1, Section 1.0, pg. 2), 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.	As explained in a letter to the CPUC and NTSB on April 6, 2011, the version of RMI 6 submitted to the NTSB was in error. The final version of rev. 1, which was signed and published on 4/5/11, did not include any provision concerning MOP plus 10 percent.

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I.a.(3)	C.01.a.iv and xi	NOV 192.917 (e)(3) NOV 192.917 (e)(4)	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 1, page 2 of Kiefner and Associates report [0215-1108 Final Report]) where the manufacturing and construction defect threat was identified, and also provided a report by Kiefner and Associates analyzing this data.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 (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). As noted in the report, the analysis did not consider any interacting threats (See pg. 2 of the report). 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 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 of49 CFR §§192.917(e)(3) and 192.917(e)(4).	PG&E believes it meets the intent of 49 CFR §§ 192.917(e)(3) and 192.917(e)(4). PG&E is analyzing the threat stability and potential for failure for every pressure increase over the maximum operating pressure (MOP) through an engineering critical assessment (ECA). The ECA approach is based on the information provided in Report 05-12 by John Kiefner. The report is referenced in PHMSA Inspection Protocols with Supplemental Guidance. It is stated in the inspection protocols that the "'M' and 'C' Charts in Appendix B of this document (see p.47) provide valuable inspection tools to help ascertain if such defects should be regarded as 'stable' or not." According to the report, a longitudinally oriented defect remains stable as long as it has not been brought to a near-failure condition by a hydrostatic pressure test itself, as long as it cannot become appreciably larger during the life of the pipeline…, and as long as no accidental over-pressurization to a level approaching its failure pressure occurs. However, the report also notes that "every piece of pipe made in accordance with API Specification 5L, 5LX, or 5LS has been subjected to a hydrostatic test by the manufacturer...So even if a pipeline has not been subjected to a test to 1.25 times its MAOP, there exists a lower bound for failure pressures based on the mill test pressure applied to any particular order of API line pipe…" The 62.65 miles of line pipe within PG&E's system that were determined through the ECA to have a stable threat were hydrostatically pressure tested in the mill and the over-pressurizations (all less than 8% over the MOP) are not thought to have enlarged any existing defects. Enlargement of any existing defects was determined to be unlikely because they would have survived the mill hydrostatic pressure test and are not expected to have failure pressures within 8% of the MOP. PG&E considers the use of an ECA for pipeline segments within the PG&E system that have experienced an increase in pressure over MOP sufficient to declare the threat of manufacturing-related defects a stable threat that does not require an integrity assessment. Also listed in the table are 2.92 miles of pipe that required a further review. Pursuant to 49 CFR 192.917(e)(3) and 192.917(e)(4), PG&E prioritized these segments as high risk in the 2011 BAP. As a note of clarification, the Kiefner and Associates report does not state that the interaction of cyclic fatigue and manufacturing-related defects was not considered, but rather qualifies that the defects were stable absent interacting threats. PG&E has enhanced its process related to interaction of threats in the newly created RMP-16. PG&E understands the concerns of CPSD regarding potential damage to any existing manufacturing-related defects following the mill pressure test. PG&E plans to pressure test all segments within its system that rely on mill pressure tests within the next 3 years.

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I.a.(4)	C.01.a.iv and xi	Follow Up Question #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 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.	Note: CPSD does not mention the use of crack detection tools (such as TFI) which PG&E has used to assess seam integrity. Table 1 (attached) is an updated summary table showing the results of hydrostatic pressure testing where completed. No hydrostatic test failures have been experienced on these pipeline segments.
I.a.(4)	C.01.a.iv and xi	Follow Up Question #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.	Table 1 identifies planned test activities. PG&E will submit the test data to the CPSD as requested following the testing.
I.a.(4)	C.01.a.iv and xi	Follow Up Question #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. 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.	Table 1 identifies the planned test activities. PG&E will submit the test data to the CPSD as requested following the testing.

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I.a.(5)	C.01.a.iv and xi	Concern	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 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. RJ\JtP-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).	The contents of the “Integrity Characteristics of Vintage Pipeline” are not referenced, whole or in part, by Part 192, ASME B31.8, or ASME B31.8S, nor are there any specific requirements related to the evaluation of hard spots; therefore, PG&E’s incorporation of a portion of the contents of “Integrity Characteristics of Vintage Pipeline” is considered compliant. “Integrity Characteristics of Vintage Pipelines” identifies two approaches to mitigating the potential risk of hydrogen cracking at hard spots or arc burns: coatings and cathodic protection controls. • An undamaged coating with good adhesion prevents a hard spot or arc burn from being exposed to hydrogen. Most coating has some damage, though, but the amount of bare steel is small even in a poorly coated line. As a result, the likelihood that a given hard spot is exposed by coating degradation is not significant from an integrity perspective. • The second mitigation method for hydrogen stress cracking is tight control of cathodic protection potentials. In order for cracks to form, the hard spot or arc burn must be exposed to an environment where diffusion of atomic hydrogen into steel can easily occur. On pipelines, hydrogen at the pipe surface can be generated when the cathodic protection potential is above (more negative than) -1.2 volts relative to a copper-copper sulfate electrode. A potential above (more negative than) -0.85 volts is typically used to control corrosion on pipelines. PG&E has selected the second mitigation option and considers the hard spot to be stable at the time of implementation of the mitigation because the growth mechanism will have been arrested. Furthermore, coating type, coating condition, cathodic protection (CP) system type, CP maintenance, CP history, CP survey history, the threat of hard spots, and operating stress level are all data that is considered and integrated as part of the ECDA pre-assessment process described in PG&E’s RMP-09. However, as part of its continuous improvement efforts, PG&E has revised its risk management procedures. According to Section 7.4 of RMP-16, “where a manufacturing defect (body of pipe) threat is identified, the threat shall be managed through P&M measures described in RMP-06 and RMP-17. Additionally, the potential for growth of any existing hydrogen stress cracking through cyclic fatigue is considered through PG&E’s cyclic fatigue process described in newly created RMP-16. The update to the threat identification process was completed on 8/14/2012, and was prior to notification by the CPUC on 8/31/2012 of a potential violation.

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I.b	C.01.a.vi and viii	NOV 192.917 (a)	Integrity Management Inspection Protocols C.Ol.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 ASMEIANSI 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" (ASME B31.8S-2004, Section A6.1, pg. 49; Equipment is defined as"... Pipeline facilities other than pipe and pipe components.'') threats. PG&E assumes Incorrect Operations and Equipment failure threats to exist for all HCAs in the entire system (RMP-06. Rev. 6. pg. 31). 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 (ASME 831.85: Appendices A6 and A8, pages. 49 and 52 respectively) 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).	PG&E believes it is compliant with the requirements of § 192. 917(a). This section of code specifically covers threat identification and requires that an operator must identify and evaluate threats to each covered segment. Potential threats that an operator must consider include but are not limited to the threats listed in ASME B31.8S. To meet this requirement, RMP 6, Section 3.5 (Revision 6) provides threat identification procedures for all threats listed in ASME B31.8S. Furthermore, PG&E 's procedure further indicates that PG&E considers Incorrect Operations and Equipment Failure to be a threat on all covered segments. The CPUC's reference to PG&E's risk assessment procedure (RMP-01) is outside the scope of the requirements listed in 192.917(a). As such, PG&E is not in violation of 192.917(a). However, as part of its continuous improvement efforts, PG&E has amended its risk assessment procedures. The update to the risk assessment procedure (RMP-01) was completed on 7/29/2012, and was prior to notification by the CPUC on 8/31/12 of a potential violation. PG&E's updated risk assessment procedure now includes the assignment of risk for equipment failure (EQ) and incorrect operations (IO) and is detailed in RMP-19 which was published on 8/14/12.

CPUC Letter Item #	PHMSA Protocol	Type of Finding	CPUC Finding	PG&E Response
I.c	C.01.a.x	NOV 192.917 (e) 192.917 (e) (2)	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. 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 ("Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines") 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.	RMP-06 section 3.5 which covers threat identification of revision 6 (which was in effect at the time of the audit) identifies, "Stresses leading to cyclic fatigue increase or other interacting threats or (iv) for seam failure* on a covered or non-covered segment, covered segments of similar pipe will be considered to have an unstable manufacturing threat." The Kiefner report does not only include pressure induced cyclic fatigue; the report also considers internal flow-induced vibration, vortex shedding, thermal expansion, and structural vibration (e.g., pipeline attached to bridges). Furthermore, as stated in the CPSD finding, PG&E does include the consideration of external forces on the pipeline in RMP-04. The factors considered in the Weather-Related and outside force threat algorithm include crossings, unstable soil, seismic areas, erosion areas, ground movement mitigations, and girth weld condition.

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I.c (cont.)	C.01.a.x	NOV 192.917 (e) 192.917 (e) (2)	There are a number of assumptions used in the Kiefner report to estimate the expected life of a pipeline segment due to pressure induced cyclic fatigue, including defect geometry, test pressure (if applicable) and the magnitude and frequency of pressure cycling (See "Evaluation of the Stability of Manufacturing and Construction Defects on Natural Gas Pipelines" (final report 05-12R, April 2007), Table 6, pg. 28). 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." ("Evaluation of the Stability of Manufacturing and Construction Defects on Natural Gas Pipelines'' (final report 05-12R, April 2007), pg. 25)	The threat identification procedure in RMP-06 revision 6 requires PG&E to consider cyclic fatigue and other interacting threats when performing threat identification. Pressure cycle fatigue and minimum time to failure for a given segment are also considered as part of the LTIMP process. Section 7.2 of RMP-06 states that "Both the regulatory requirements for re-assessment schedules (such as the maximum re-assessment interval chart) and the engineering basis (remaining half-life calculations) must be considered when establishing re-assessment intervals." As part of its continual improvement process, PG&E created a new RMP for threat identification (RMP-16) which contains more detailed processes related to cyclic fatigue and interacting threats. The enhancements to the cyclic fatigue evaluation process include pressure cycle calculations and evaluation against criteria to determine susceptibility for cyclic fatigue. The update to the threat identification process was completed on 8/14/2012, and was prior to notification by the CPUC on 8/31/2012 of a potential violation.
I.c (cont.)	C.01.a.x	NOV 192.917 (e) 192.917 (e) (2)	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.	It is incorrect to state that PG&E does not consider cyclic fatigue in its threat identification process. As previously noted, RMP-01 is a procedure that addresses risk assessment. Its scope does not address threat identification and it is incorrect to reference this procedure to support any finding related to threat identification. Additionally as discussed above in Comment #5, PG&E considers cyclic fatigue in its threat identification procedures and provides RMP-06 revision 6, Section 3.5 in support of this. Again, it is noted, that as part of its continuous improvement efforts, PG&E has enhanced its procedure in this area. It has created RMP-16, "threat identification" which a more detailed process for threat identification and has added sections specifically to address cyclic fatigue threat and threat interaction. This addition to PG&E's threat identification process was completed on 8/14/2012 and was performed prior to notification by the CPUC on 8/31/12 of a potential violation.

CPUC Letter Item #	PHMSA Protocol	Type of Finding	CPUC Finding	PG&E Response
I.d.	C.01.c	Concern	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(RMP-06, Rev. 6, Section 2.3, pg. 19) 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.	PG&E's threat identification process was updated on 8/14/2012 to provide additional detail related to the potential for interactive threats and was completed as a continuous improvement by PG&E. The update included the creation of a separate procedure (RMP-16, Threat Identification) that is specifically for the threat identification process. This work was completed prior to notification by the CPUC on 8/31/12 of a potential violation.
I.d. (cont.)	C.01.c	Concern	The PG&E Criteria for Seam Stability Analysis (RMP-06, Rev. 6. Section 3.5, Table, pg. 30) 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) (ASME B31.8S-2004. Section 2.2. pg. 5)	PG&E agrees that this could be stated clearer. As part of its continual improvement process, PG&E created RMP-16 for threat identification. This document provides flow charts for the determination of seam stability which clearly specify how cyclic fatigue is considered. Additionally, Section 8 in RMP-16 provides details regarding potential interactive threats.

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I.e	C.01.d	NOV 192.917 (c)	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]" 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 (RMP-06, Rev. 6. Section 3.5, pg. 31). 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).	PG&E meets the requirements of § 192.917(c) Revision 6 of PG&E's Integrity Management Program (RMP-06) clearly states in Section 3.5 that PG&E assumes that that equipment threat and incorrect operations exist on all covered pipeline segments. Therefore, these threats are never eliminated. It further references that cyclic fatigue and interacting threats must be considered. As such, there has also been no elimination of the cyclic fatigue threat from the threat identification process. As part of PG&E's continuous improvement process, PG&E has created a new RMP (RMP-19) to include incorrect operations and equipment into its risk algorithm. The improvements to PG&E's process were completed prior to notification by the CPUC on 8/31/12 of a potential violation. PG&E has made improvements to its threat identification process, including the development of a new RMP (RMP-16 Threat Identification). This document contains a more detailed process for the evaluation of cyclic fatigue. PG&E followed the risk assessment process established in ASME B31.8S section 5 as required by § 192.917(c). Pursuant to these requirements, PG&E established a relative risk assessment methodology. PG&E agrees that we did not perform risk assessment for Incorrect Operations, Equipment Failure and threat categories.

CPUC Letter Item #	PHMSA Protocol	Type of Finding	CPUC Finding	PG&E Response
I.f	C.02.a	NOV 192.917 (b)	"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 § t 92.917(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 ASMEIANSJ 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." 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."(RMP-06 Rev. 6, Section 2.4, pg. 23) 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).	49 CFR § 192.917(b) covers data gathering and integration and does not provide a timeframe in which data gathering should be performed. It is unclear what basis the CPSD is advocating for a violation. Per revision 6 of RMP-06, PG&E performs data gathering and integration of its data sets for threat identification and risk assessment. The CPSD referenced a paragraph that denotes the data elements for use in PG&E's initial threat identification and risk assessment data gathering and integration efforts; however the CPSD overlooked the following paragraph in RMP-06 which references data integration for future analysis will be performed on an annual basis. Thus, while not required by code, PG&E has provided a minimum timeframe in which it performs data gathering and integration of new data into its overall program. PG&E does not agree that code requires a timeframe and does not agree that it has violated § 192.917(b). PG&E has developed its data gathering program per the requirements of ASME B31.8S, which is required per § 192.917(b), and actively updates its data sets as new and improved information becomes available.

CPUC Letter Item #	PHMSA Protocol	Type of Finding	CPUC Finding	PG&E Response
I.g	C.02.b	NOV 192.917 (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 83 1.8S-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 l) 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: (RMP-05, Rev. 5, pg. 7, Section 6.1. Item F footnote) "Leaks within the last twenty years on a pipe segment or on adjacent segments 1vith 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.	This finding appears to be a duplicative of follow-up questions from the NTSB report issued in September 2011 and a data request from Bob Cagen of the CPUC on September 30, 2011. (CPUC_012-Q05). As previously noted in PG&E's response dated October 14, 2011, RMP-05 is a procedure on how risk values are assigned upon pipeline segments. It does not provide instruction on data gathering and integration or threat identification which § 192.917(b) covers. It has been incorrectly cited by the CPSD as a basis for a violation as it cites that a risk assessment procedure should follow regulatory requirements for threat identification, which 49 CFR 192 regulations clearly denote as different processes. Furthermore, both protocol C.02.B and §192.917(b) make reference to a specific list of data that should be collected for covered and non-covered segments, and collecting data regarding all leaks is not specifically required; rather past incident history needs to be collected. 191.3 defines incident to mean any of the following events: (1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences: (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; (iii) Unintentional estimated gas loss of three million cubic feet or more; (2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident. (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition. As described in RMP-06 Section 2.4, PG&E did gather data regarding incident history. Therefore, PG&E is compliant with the requirements of 192.917(b).

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			The procedure in RMP-06 for identifying data sources for the risk model lists "typical" sources?2 PG&E should identify the specific sources of data it uses in the risk model.	PG&E utilized the word "typical" to be consistent with ASME B318.S Table 2. RMP-06 clearly states that 'The B31.8S sources utilized by the Company and the additional Company-specific sources are presented in the following table. Therefore, the table does identify the specific sources of data utilized. PG&E have removed the use of the word 'typical' from its most current version of RMP-06 in order to improve clarity regarding the data sources that are being utilized.
I.h	C.02.d. i.-iv.	NOV 192.917 (c)	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 83 l .8S-2004, Section 4.4, and ASME B31.8S-2004, Appendix A [ASME 831.8S-2004, Section 4.1, ASME 831.8S-2004, Section 4.2.1, ASME B3l.8S-2004, Section 4.4, ASME B3 1.8S-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. 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." (RMP-06, Section 2.5, pg. 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).	As part of PG&E's Pipeline Safety Enhancement Plan (PSEP), records collection and MAOP validation was performed for all pipelines located in HCA's and was completed in January 2012. PG&E is continuing work to validate all remaining transmission lines in non-HCA's and is estimated to have this work complete d by early 2013. The updated feature lists created by this effort are in the process of being incorporated into the integrity management program. PG&E utilizes data contained within GIS to support its threat identification and risk assessment processes. The mapping group has the following controls in place: • The current A-forms have a documented mapping review for each form prior to entry into GIS and there is a documented process for how to fill out the forms. • The current H-forms do not include a mapping review sign off, but they are signed off by the person performing the inspection, that person's manager, and a third approver of the form. • The mapping department has a policy that the lead mapper verifies as-builts before the mappers post them. As a part of its continual improvement process, PG&E has expanded Quality Assurance (Section 17.0) guidance. Section 17.5 "Data Verification" in RMP-06 Rev. 08 provides reference to PG&E's "Data Assurance" program including: • MAOP Data Validation Project • Mapping procedures • Assessment result verification • Leak data verification

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I.i	C.02.f.ii	NOV 192.917 (e) (1)	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 B3l.8S and 49 CFR § l92.917(e)(1) through other measures. 49 CFR §192.917(e)(1) states: " ... An operator must utilize the data integration required in paragraph (b) of this section and ASMEIANSI B31.8S, Appendix A 7 to determine the susceptibility of each covered segment to the threat of third party damage ... the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing ... " 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 lnspections (ILl) 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.	PG&E is in compliance with §192.917 (e) (1). The identified finding incorrectly mixes the 3rd party damage risk analysis process with the 3rd party damage assessment data analysis process. PG&E has integrated data from past encroachments that have resulted in known damage as well as known line crossings as part of the risk assessment process. For threat identification, all active line segments have been designated as having the threat of 3rd party damage and thus the threat as well as associated P&M measures apply to all covered and non-covered segments within the PG&E gas transmission system. Until recently, the USA data was not available in a useful format for direct alignment with pipeline locations, but now that this information is available PG&E is incorporating this data into the risk assessment process by assigning USA ticket to individual pipeline segments. This change was just incorporated into the Risk Management Procedures that were updated and re-issued in August of 2012 and will be reflected in the risk and threat analysis process planned for 4th quarter of this year. There are two specific practical issues in regards to utilization of USA tags in combination with ILI or ECDA data in terms of feeding the risk assessment process. First, the available USA data is not geospatially specific enough to correlate with specific signal or anomaly locations obtained via ILI or ECDA inspections, respectively. The second issue is that the integration of ECDA indications or ILI anomaly locations occurs after Phase 2 of these inspections, not during the threat assessment process and thus the data is not available during threat assessment process. The LTIMP, or Long Term Integrity Management Program outlined in RMP 17 addresses the incorporation of indication and anomaly data in the risk identification process. The LTIMP was created to identify acceptable preventative and mitigative measures and also to perform continual evaluation over the pipeline segments. RMP 17, section 6.1.3 states, “integrated data shall be reviewed to confirm the identified threats for the covered segment. The threat identification results shall be reviewed to determine if information regarding any additional threats has been discovered since the previous threat identification performed by the Risk Group.”

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I.j	C.03.a. i. and v.	Concern	lntegrity 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.	PG&E addresses the threat of incorrect operations and equipment failure through P&M measures. The need for additional P&M measures for each threat is determined by the LTIMP process as described in RMP-06 Section 9. Therefore, not including them in the risk ranking did not impact prioritization of the pipelines for integrity assessments nor did it impact the determination of the need for alternative inspection methodologies. As part of PG&E's continual improvement process, PG&E has incorporated all threats in the revised version of RMP-01. PG&E also created a separate RMP (RMP-19) for the threat algorithms for Equipment Failure and Incorrect Operations. For discussion of enhancements that have been made related to cyclic fatigue threat considerations, please refer to PG&E's response to Item 5. The update to the risk assessment procedure (RMP-01) was completed on 7/29/2012 and RMP-19 was issued 8/14/12, both prior to notification by the CPUC on 8/31/12 of a potential violation.
I.k	C.03.c.i	Concern	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)] ..." ln 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:	See below

CPUC Letter Item #	PHMSA Protocol	Type of Finding	CPUC Finding	PG&E Response
I.k	C.03.c.i	Concern	1. RMP -01: A. The Consequence of Failure (COF) algorithm consists of four factors. (RMP-01, Rev 5, page 5.) These factors are the Impact on Population (IOP), lmpact on the Environment (IOE), lmpact on Reliability (lOR) and the Failure Significance Factor (FSF). The formula for assigning points to the lOP 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.	As stated in RMP-01 Section 6.2, PG&E utilizes a relative risk calculation based on an indexing model and qualitative scoring approach. RMP-01 further states that "The scoring shall be based on expert direction from appropriately staffed Steering Committees." 'Consequence' is one of the steering committees. Section 6.4.1 of RMP-01 discusses IOP specifically and states that the IOP shall be calculated per the direction of the Consequence Steering Committee. The committee had determined that the factors in A through C of this section are significant for determining the Population Impact of a gas pipeline failure. Section 6.4.1 c) provides documentation of how points specific to PIR are assigned. ASME B31.8S Section 5.5(b)(2) describes relative risk models and states that the relative methods "identify and quantitatively weigh the major threats and consequences". The approach that PG&E has taken to determine COF is consistent with what is described in ASME B31.8S. The process is well documented and the technical justification for all points awarded is SME judgment.
I.k	C.03.c.i	Concern	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-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 300ft., whichever is greater.	PG&E utilizes Failure Significance Factor (FSF) to reduce the calculated COF for locations where it is expected that the pipeline would leak instead of rupture All pipelines operating above 20% SMYS receive a FSF factor of 1. Additionally, all pipeline segments operating at less than 20% SMYS and where wall-to-wall paving conditions exist are also assigned a FSF value of 1. A FSF value other than 1 is rarely assigned and PG&E considers its existing criteria to be sufficiently conservative. Additionally, because the FSF is looking at the reduced impact of a leak, the PIR which is used to help determine the relative consequence of a rupture (i.e., not a leak) is not deemed to be relevant.
I.k	C.03.c.i	Concern	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.	Section 7.1 has been removed in the current version of RMP 01. (Note: CPSD states that no response is needed to this comment.)
I.k	C.03.c.i	Concern	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." (RMP-01,Section9,pg.17) 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.	The COF did not consider all HCA's equal; the relative size of failure was used to differentiate HCAs from a consequence perspective. As a part of PG&E's continual improvement process, RMP-01 was updated on 3/26/12 to remove the second COF formula that was previously utilized to calculate 'HCA risk'. All COF values are now calculated based on the COF formula described in Section 6.4 of RMP-01 revision 6 (Section 8.4 of Revision 8).

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I.k	C.03.c.i	Concern	2. RMP-02 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 assess 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.	The EC threat algorithm has been modified from RMP-02 Rev. 05 to RMP-02 Rev. 07 to reflect these two comments. A. The default value in subpart A of the EC Threat Algorithm was changed so the default value is now the highest point allocation. B. A clarifying statement has been added to the subpart H of the EC Threat Algorithm from RMP-02 Rev. 05 to RMP-02 Rev. 07 that "Risk Management Engineer and Corrosion Engineer will jointly determine level (high or medium) for each potential location of interference. Both instantaneous voltage/current measurements and fluctuations over time should be considered." to provide additional guidance to the risk and corrosion engineers. The presence of voltage sources within 500 feet of a pipeline segment may or may not imply interference. However, if a voltage source is present, then there is an increased likelihood of interference occurring.
I.k	C.03.c.i	Concern	3. RMP-03 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.	RMP-03 was revised to consider one-call ticket frequency. The current revision of RMP-03 (Revision 7, dated: August 6, 2012) considers the frequency of Underground Service Alert (USA) tickets when calculating the likelihood of failure (LOF).
I.k	C.03.c.i	Concern	4. RMP-05 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 .(RMP-01. Equation 2. pg. 8) 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 DSA W pipe that has a history of incidents associated with certain manufacturers. For example, DSA W pipe is listed in the “Integrity Characteristics of Vintage Pipelines" report as having pipe body incidents for certain manufacturers.	A. Test Pressure vs. Pipe Strength is assigned a weighting of 20% and all criteria except 1 for that factor were awarded negative points. Therefore this factor is considered as a mitigation factor and is not included in the 100% total. B. As a part of PG&E's continual improvement process the M&C algorithm was updated. The current revision of RMP-05 (Revision 7, Dated July 29, 2012) assigns a point value for DSAW pipe based on the date of manufacture. DSAW pipe manufactured prior to 1962 is assigned 20 points whereas DSAW pipe manufactured in 1962 or afterward is assigned 10 points.

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II	C.01.a.ii	Concern (data requests)	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. If such data are not available, it shall be assumed that the particular threat applies to the pipeline segment being evaluated. "(ASME B31.8S-2004, Section 4.2.1. pg. 9) 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 wi1l 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 \\ith a data request for additional information that will provide a sampling of gas transmission line documentation, justifying the exclusion of IC as a threat.	1. PG&E's natural gas transmission system receives gas from: gas wells, gas storage fields, and third-party interconnects. Gas from wells enters PG&E's system at gas well meters (also referred to as "gas gathering meters"). For a list of the gas gathering meters currently connected to PG&E's transmission system, and the lines that each well feeds into, see the worksheet titled "GGMeters" in Attachment 1. For a list of where all gas storage fields and third-party interconnects connect to PG&E's transmission system, see the worksheet titled "Interconnects" in Attachment 1. 2. See Attachment 2 for maps showing where each gas gathering meter is located. See Attachment 3 for a map showing where each third party interconnect and gas storage field is located. 3. To detect moisture in gas from storage fields and third-party interconnects, PG&E uses continuous, automated monitors. For gas from wells, PG&E uses periodic monitoring at gas gathering meters. **<u>Continuous Monitoring</u>** PG&E uses continuous moisture monitors at various points on its system, and this data is accessible in real-time on SCADA. Attachment 4 shows where these moisture monitors are located. These monitoring points cover gas entering PG&E's transmission system from storage fields (run by PG&E and third-parties), as well as gas entering PG&E's system from third-party interconnections[1]. For gas entering the system from third-party interconnections, moisture monitoring is not performed at each connection point; instead, the monitors are placed at points downstream of where multiple sources intermingle. If unacceptably high levels of moisture are detected, PG&E performs targeted inspections to determine the source of the "wet" gas. The chart below shows when PG&E's automated monitors were installed.

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				(see table and text below)

Location	Year Installed
Las Vinas	2005
Lodi Kirby Hills	2007
Lodi Sherman Is.	2006
Wild Goose Delevan	2007
Wild Goose Gridley	2006
Swingle	2008
Yuba City Holder	2008
Burney	2007
Bixler	2007
Los Medanos	2007
Hinkley	2007
Antioch Terminal	2011
Yolo Junction	2008
Gill Ranch	2009
Central Valley	2011

[1] PG&E has one storage field, Pleasant Creek, which does not have a continuous moisture monitor; however, only a small amount of gas enters the system from this point and it has been dehydrated. In addition, PG&E receives data from a moisture monitor on the Ruby Pipeline, and both the pipeline and monitor are owned by El Paso Corporation

To enhance monitoring of moisture in its system, PG&E plans to install additional continuous moisture monitors, and is currently conducting research on where this equipment could be most effectively utilized.

Periodic Monitoring

Currently, PG&E has approximately 198 gas gathering meters physically connected to its transmission system. Moisture monitoring has been performed at each of these meter locations on a periodic basis since the mid-1990's, when overall "dry gas" transport agreements were established. This monitoring consists of checking a drip pot at each meter for liquids and using a manual stain-tube moisture indicator to ensure proper moisture dew point in the delivered gas. Because PG&E monitors moisture at all gas gathering meters, the maps showing all gas gathering meters (Attachment 2) also show all the points where PG&E performs periodic moisture monitoring.

As background, prior to the mid-1990s, PG&E monitored delivery of gas from producers to ensure that the gas delivered to its transmission system had no free liquids. In addition, PG&E operated dehydration equipment at centralized locations downstream of delivery points to remove moisture. However, nearly all of these dehydration facilities were retired from service once producers began delivering "dry gas" in the early 1990s.

Input Dates

PG&E has no central data storage location for when input points began supplying gas to PG&E's system. Since some of these input points began supplying gas over 60 years ago, the data would be extremely burdensome to collect. For example, each gas gathering meter was installed when initial gas wells were drilled by individual producers and connected to PG&E at different times in the last 60 years.

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				Furthermore, since 1992, PG&E has retired and removed approximately 1000 gas gathering meters associated with depleted wells. PG&E believes that it has construction jobs associated with each gas gathering meter installation and removal in its archives. However, retrieving and reviewing these records to determine installation dates would require a lengthy and extensive effort. 4. Until recently, PG&E has evaluated its natural gas transmission line segments in high-consequence areas ("HCAs") for the internal corrosion threat per Risk Management Procedure-06, "Gas Transmission Integrity Management Program," ("RMP-06") revision 7. A list of line numbers where an IC threat has been identified and an IC assessment plan has been established is provided in the worksheet labeled "IC_threat_yes" in Attachment 5. The line numbers on this list designate transmission lines as prescribed in RMP-06, Appendix A. It should be noted that PG&E's Integrity Management program has recently created a stand-alone threat identification procedure called RMP-16, "Threat Identification." RMP-16 became effective on 8/14/2012 and it includes a revised IC threat identification process. PG&E is currently working to implement this new procedure and may identify additional HCA segments with IC threats. The data collection for implementing the new procedure is on-going and the results are expected to be available in the next assessment plan scheduled for publication in the 1st quarter of 2013. However, the pipelines identified as having an IC threat in the worksheet labeled "IC_threat_yes" that have an assessment scheduled by the end of 2012 have been validated to assure they would be considered to have an IC threat using the new RMP-16 procedure, which is more conservative that the previous threat identification procedure. 5. For a list of lines that have HCAs where internal corrosion threats have not been identified, please see the second worksheet labeled "IC_threat_No" in Attachment 5. The line numbers on this list designate transmission lines as prescribed in RMP-06, Appendix A. The "IC_threat_No" list is based on threat identification criteria from RMP-06 revision 7. As previously noted, the introduction of the new threat identification procedure RMP-16 may impact the list of lines currently identified as not having an IC threat. However, as noted above, this work is in progress.