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December 16, 2010

Mr. Michael Robertson
Utilities Safety and Reliability Branch
Consumers Protection and Safety Division
California Public Utilities Commission
505 Van Ness Avenue, 2nd Floor
San Francisco, CA. 94102-3298

Re: State of California – Public Utilities Commission
May 2010 Integrity Management Program Audit

Dear Mr. Robertson:

The Utilities Safety and Reliability Branch (USRB) conducted an extensive, two-week long General Order 112-E audit of PG&E's Transmission Integrity Management (IM) Program from May 17 – 28, 2010. This comprehensive audit was supported by four USRB staff auditors and more than a dozen PG&E engineers and other staff.

This letter provides an overview of PG&E's response and responds to the two areas of concern that you highlighted in your letter. Preliminarily, PG&E wants to acknowledge the hard work and dedication of the USRB auditors, and express our appreciation for their feedback regarding continued improvement of our IM Program. Although PG&E's IM Program complies with PHMSA requirements and the documents incorporated by reference in those regulations, as a result of the thoughtful and productive discussions during this audit, we have identified several ways to improve the effectiveness of our program. For example, the USRB auditors identified areas where the original integrity management program documentation does not reflect current implementation as our IM Program has matured and developed over time. PG&E plans to reconcile these areas through revisions to the IM Program procedures, as discussed in detail in the two attachments.

The USRB's audit attachment includes 65 numbered findings which address 76 separate issues (some findings include multiple issues). Of the 65 findings, USRB auditors and PG&E engineers identified several areas for improvement in our IM Program. In Attachment A, we discuss each of the 65 findings, explaining in detail where we agree the program can be improved as suggested, and also explaining where we do not think the suggested changes are warranted. Although PG&E has not agreed with every item brought forth by the USRB, we acknowledge the USRB's leadership and direction. PG&E wants to be an industry leader and will continue to make program improvements based on the USRB's guidance.

In addition to the USRB's specific findings, your letter identified two general areas of concern. Your first concern involved the exception process and the second concern was regarding PG&E's responses to the audits done in 2007 and 2009 by consultants retained by PG&E to help us improve our program. In each area of concern, your letter set forth several specific items. Attachment B sets forth PG&E's response to the specific items raised in your letter itself. However, PG&E acknowledges that the exception process and our responses to these audits are critical components of the IM Program and that increased rigor can improve the effectiveness of these processes.

Regarding exception reports, PG&E's procedure RMP-06 describes the procedures to be followed when a deviation from established integrity management procedures is appropriate. PG&E agrees with USRB that IM personnel have tended to use the exception report process to document more than just procedural exceptions and have issued exception reports when they weren't necessarily needed (i.e. no procedural exception was actually being taken). PG&E agrees that this is an over-use of exception reports and we will take steps to reduce this practice.

Regarding the external audits, PG&E acknowledges that, although it does specifically require the audits to take place, RMP-06 does not provide clear direction regarding a formal response and closure of any issues identified. PG&E agrees with USRB that addressing this concern will add additional rigor and clarity and will improve our overall process. RMP-06 will be updated during the next revision to bring more clarity and rigor to Section 13.8. Additionally, all corrective actions resulting from future audits will be tracked via PG&E's established commitment tracking process managed by PG&E Gas Engineering Regulatory Support.

Again, I want to acknowledge USRB's thorough and professional audit of PG&E's IM Program. The auditors gave generously of their time and the candid discussions produced many useful ideas to improve our program. As noted in the attached table, we intend to implement many of USRB suggestions to enhance future integrity management assessments.

If you have any questions concerning this report, please contact Redacted t (Redacted

Sincerely,

Glen Carter
Senior Director, Gas Engineering

Attachments – under separate cover

cc: Julie Halligan, California Public Utilities Commission
Raffy Stepanian, California Public Utilities Commission
Sunil Shori, California Public Utilities Commission

ATTACHMENT A
PG&E's Integrity Management Program
Responses to Findings Raised in CPUC's October 21, 2010 Letter

Item	CPUC Audit Finding	PG&E's Response
1	Referencing PHMSA Protocol A.01.d, CPUC stated: We were unable to confirm if all HCA segments existing in 2004 were added to the baseline assessment by December 17, 2004. In addition, we are concerned there may be other MOP segments that are 20% transmission, which may not have been included in the baseline assessment. We requested that PG&E provide information related to a study being performed by the company to confirm this, but PG&E indicated no documentation was available. 49 Code of Federal Regulations (CFR), Part 192, §192.947(d) requires such documentation to be maintained and available for review during an inspection.	PG&E is working to ensure that all HCA segments existing in 2004 have been included, and PG&E meets the requirements of 49 CFR §192.907, §192.911(a) and 192.947(d). PG&E has documented the original High Consequence Area (HCA) pipeline segments in the 2004 Baseline Assessment Plan (BAP). Any subsequent changes to the HCA pipeline segments as a result of the annual review process are documented in revisions of the BAP. The original 2004 BAP and the latest approved BAP were provided to the CPUC audit team. The annual HCA review process identifies any transmission segments that may not have previously been HCAs. These changes are included in the HCA reports which are prepared by county every year. PG&E provided examples of the HCA county review reports to the CPUC audit team. PG&E understands the CPUC's concern that there may by other transmission segments that may not have been included in the BAP, and prior to the audit we had initiated a comprehensive review to address that potential issue. In April of 2010, as part of PG&E's continuous improvement efforts, a system-wide study was initiated to ensure proper calculation of Maximum Operating Pressure (MOP), which is used to identify HCAs. Because this large system-wide study was still in the preliminary stages during the May audit, PG&E did not have information ready to present to the audit team. This study is still in progress and the final results will be provided to the CPUC by March 31, 2011.
2	Referencing PHMSA Protocol A.02.a, CPUC stated: PG&E has no requirement to use the 0.73 factor for rich natural gas.	PG&E has a requirement to use the 0.73 factor for rich natural gas, but we agree the process is not well documented. For natural gas, ASME B31.8S section 3.2 requires that a factor of 0.69 be used to calculate the Potential Impact Radius (PIR) around the pipe. Section 3.2 goes on to require "other factors" to be used for rich natural gas (which neither B31.8S nor 49 CFR 192 defines). PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) complies with section 3.2 by requiring an HCA identification review for all pipelines where the British Thermal Unit (BTU) content exceeds 1100 BTU/scf. PG&E considers BTU/scf heating content above this threshold to be rich. PG&E performs and documents the review annually. In the course of the audit, PG&E presented to the auditor a letter to file in which a

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		Senior Engineer documented that a factor of 0.73, instead of 0.69, was used for the PIR calculations where the heating value of the gas was found to exceed 1100 BTU/scf. (See Attachment) PG&E agrees that the process for calculating the PIR for rich natural gas is not well documented. In the next revision of RMP-06, PG&E will document the process used to verify the proper PIR calculations are completed when rich gas is found.
3	Referencing PHMSA Protocol A.03.a, CPUC stated: PG&E RMP-06 didn't list the sources for the data selected in identifying the identified sites.	PG&E's Risk Management procedures list the data sources, and PG&E meets the requirements of 49 CFR §192.903, §192.905(b) and §192 Appendix E, I(c). For those buildings or outside areas meeting the criteria specified by §192.903, PHMSA protocol A.03a requires that the operator's identification of identified sites includes the sources listed in §192.905(b) and that the source of information selected is documented. Section 1.2 of PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" refers the reader to Risk Management Procedure-08 "Identification, Location, and Determination of High *Consequence Areas" for Identified Sites. PG&E's RMP-08 Section 6.0 defines* an Identified Site and also lists data sources. These data sources include: The California Department of Social Services, people who live near vicinity of pipeline, public information available on the internet, personal knowledge, and feedback from emergency personnel and from integrity assessment teams. RMP-08 Section 7.3 further states that a key data source is the land use information in the parcel data utilized each year to identify new HCAs. PG&E provided copies of RMP-06 and RMP-08 to the CPUC audit team.
4	Referencing PHMSA Protocol A.03.b, CPUC stated: PG&E has no process for assuring that any HCA information received from sources outside the IM Group is properly and timely tracked, documented, and integrated into the BAP.	PG&E has a process for assuring that HCA information received from sources outside the IM Group is properly and timely tracked, documented, and integrated into the BAP, and our process meets the requirements of 49 CFR §192.905(b). As documented in PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program", PG&E integrates HCA information from public officials and external sources as follows: 1 - Annually purchases parcel date prepared by public agencies that documents the parcel use 2 - Annually purchases licensed care facility information that is prepared by the State of California 3 - The Vice President of Engineering has informed all Gas employees to notify the Integrity Management group of potential identified sites via e-mail or through

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		the Company-wide GIS web applications notification process 4 - At the regular district level meetings with emergency responders, PG&E requests input on locations not previously identified as identified sites 5 - Access for public officials to on-line maps of PG&E's transmission lines and known HCAs. This last item is under development and will be available in 2011. The Integrity Management team evaluates data received from the above external sources and integrates the information into the BAP accordingly. A copy of RMP-06 and examples of the HCA reviews (which document the integration of the above information) were provided to the CPUC audit team.
5	Referencing PHMSA Protocol A.05.a, CPUC stated: PG&E is not using prorating. PG&E is using MOP instead of MAOP to determine where HCA segments exist on its system which is an issue. PG&E is conducting a survey to identify any portions of its pipeline system where MOP and MAOP of line, applied to a given segments characteristics (i.e., pipe wall thickness) would render the segment as being 20% transmission and subject to IM, Subpart 0 requirements. This may result in additional HCAs being identified. Such an identification should have occurred much earlier in the program. We requested that PG&E provide copies of updates it has received from its vendor (Dan Curtis -MEARS) related to the survey. However, PG&E refused to provide the updates although the audit team believes they are reviewable documents (CFR §192.947(d)).	PG&E agrees that it is not utilizing the option of prorating, but PG&E meets PHMSA's requirement to use the pressure of the limiting component to determine the PIR and satisfies the requirements of 49 CFR §192.903. As documented in PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" and TD-4125P-02 (See Attachment) and in accordance with 49 CFR 192.619 (a)(1) which defines the Maximum Allowable Operating Pressure (MAOP) as "the design pressure of the weakest element", PG&E uses the acronym MOP to define the MAOP of a pipeline based on its weakest element. PG&E's use of MOP correctly meets PHMSA's requirement to use the pressure of the limiting component to determine the PIR. In April of 2010, as part of PG&E's continuous improvement efforts, a system wide study was initiated to ensure proper utilization of Maximum Operating Pressure (MOP) to calculate HCAs. This study is still in progress and the final results will be provided to the CPUC by March 31, 2011.
6	Referencing PHMSA Protocol A.05.b, CPUC stated: Same as A.05.a.	Refer to Item No. 5 for PG&E's response.
7	Referencing PHMSA Protocol A.06.a, CPUC stated: PG&E needs to modify its RMP-06 (Sections 17.2 and 17.3) to add a process to more thoroughly review new HCAs in order to identify any that existed during previous reviews, but were somehow not identified and missed from inclusion into the IMP. Such a review should document the reason(s) for the HCA being	PG&E meets the requirements of 49 CFR §192.905(c) but agrees that we should consider strengthening our procedures. PG&E's review process for HCAs is documented in PG&E's Risk Management Procedure-08 "Identification, Location, and Documentation of High Consequence Areas (HCAs)" (RMP-08) which was provided during the audit. The annual HCA reviews that are conducted are documented in reports by county which identify all

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	added to the IMP as well as a determination of why the HCA may not have been identified during the last review. The review process could help PG&E identify program deficiencies (i.e., errors in pipeline data, buffers applied, etc.) that could be attributing to all HCAs not being identified and included in it IMP.	changes to HCAs including the addition of HCAs and how they were identified. Examples of the HCA reviews were provided to the CPUC audit team.
8	Referencing PHMSA Protocol B.01.b, CPUC stated: PG&E has not documented that it is evaluating all the considerations from ASME B31.8S, Section 6.2.5, for selecting an internal inspection tool. PG&E RMP-11, Section 4.3.1.2 has some, but not all, of the ASME B31.8S considerations listed.	PG&E meets the requirements of 49 CFR §192.921(a)(1) and ASME B31.8S-2004, Section 6.2.5, but PG&E will revise its procedures to provide additional clarity. ASME B31.8S lists 3 main categories of considerations each with sub-categories. PG&E's Risk Management Procedure-11 "In-Line Inspections" (RMP-11) documents all applicable considerations listed. PG&E does not consider "Type of Fluid, Gas or Liquid" since PG&E only operates natural gas pipelines. In addition, PG&E's Pre-Assessment Form A also documents required considerations. While all considerations are addressed in the procedure, the procedure does not specifically reference "ASME B31.8S section 6.2.5". To provide additional clarity, PG&E will add the reference to "ASME B31.8S section 6.2.5" in the next revision of RMP-11.
9	Referencing PHMSA Protocol B.02.a, CPUC stated: PG&E's GIS has specific dates for reassessments; however, not for assessments. PG&E is not updating its BAP with specific dates and is only documenting the calendar years for reassessments and assessments still to be performed even those that are near term. Pipeline and Hazardous Materials Safety Administration (PHMSA) FAQ-39 suggests specific dates be indicated in BAP updates as assessments come closer in time to being performed.	PG&E meets the requirements of 49 CFR §192.921(a) but we will incorporate your suggestion to add specific dates. PG&E has a schedule for all of the covered segments not already assessed. However, while PG&E notes the year planned for initial inspections, PG&E acknowledges the CPUC's suggestion to add specific dates as assessments are coming closer to being performed. Therefore, PG&E will add these specific dates (in addition to the year) in the next issuance of the BAP. For re-assessments a specific date is identified in the Long-term Integrity Management Plan (LTIMP) and tracked by the Integrity Management team.
10	Referencing PHMSA Protocol B.02.c, CPUC stated: PG&E RMP-06, Section 4.3, does not include the requirement to prioritize LFERW as high risk for any "covered or non-covered segment where in the pipeline system ... has experienced seam failure." (I.e., *it speaks to covered; but not to non-covered* segments.)	PG&E meets the requirements of 49 CFR §192.917(e)(4) but we agree with your suggestion to add specific language to include "non-covered" segments. PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) references covered segments; however, it *does not include specific language on non-covered segments even though non-*covered segments meeting this criteria are appropriately prioritized. To provide

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		clarity, PG&E will include the term "non-covered" in the next revision of RMP-06.
11	Referencing PHMSA Protocol B.02.e, CPUC stated: PG&E needs to have date specific information, in the BAP as assessment dates approach. Also, for DA, PG&E is considering the end of its ECDA Step 3 as being the end of its assessment and counting the mileage as completed for DA. However, per PHMSA FAQ-34, the baseline assessment is not considered complete until "the last direct examination associated with direct assessment is made..." Per NACE RP0502-2002, Figure 7, direct examinations for process validation, performed per NACE ' RP0502, Section 6.4.2, are the last direct examinations associated with direct assessment. Therefore, it appears that PG&E may be incorrectly counting completed DA mileage within its IMP.	As stated in response to Item No. 9, PG&E meets the requirements of 49 CFR §192.921(a) but we will incorporate your suggestion to add specific dates. With respect to Direct Assessment, PG&E meets the requirements of 49 CFR §192.933. PG&E completes all required digs as part of the External Corrosion Direct Assessment (ECDA) and correctly reports completed IMP mileage. NACE RP0502-2002 6.1.4.3. states "The Post-Assessment Step includes... assessment of ECDA effectiveness...". Within the same section the accompanying Figure 7, which is mentioned in the finding, is titled "Post-Assessment Step" and indicates these actions occur after the Direct Examination step is completed. PG&E adheres to the direction provided in NACE RP 0502-2002 where the effectiveness digs are completed in Step 4 so that information learned in the prior Steps 1-3 can be incorporated into the selection of the best effectiveness examination locations.
12	Referencing PHMSA Protocol B.03.a, CPUC stated: The PG&E LTIMP for Line 300A South identified a Hard Spot threat; however, no assessment has been conducted for this threat. (Line 172 had an identified hard spot failure and an III tool capable of hard spot detection was run on that line on 5/24/2005.) A corrosion growth rate of 1 mil/year was used on 300A South (amended report) while 12 mils/year was used on Line 57B because no "detailed CP information" was used by the corrosion engineer. PG&E needs to justify the corrosion growth rates used in determining reassessment intervals. As noted in RMP-09, Section 6.2.2.3, "Exceptions: ASME 831.8S (2001) page 63, Table 81, shows average corrosion rates related to soil resistivity which are provided in Table 6.2.1. Other corrosion rates that are scientifically supported may also be used. The Manager of CE&DA shall approve using these rates..." Therefore, please provide the justification for the 1 mil/year corrosion rate identified for Line 300A South and the approval of the manager of CE&DA.	PG&E meets the requirements of 49 CFR §192.921(a), §192.933, §192.921(e), §192.919(a), §192.919(b), and §192.919(d), although we will revise our procedures to address some of the issues mentioned. Hard spots are not a recognized threat in 49CFR192 Subpart O. Completion of an assessment or mitigation of this hard spot threat is not necessary to declare a pipeline's integrity assessment complete. As a proactive response to the guidance in Interstate Natural Gas Association of America's (INGAA) Vintage Pipe Report guidelines (see attached), PG&E includes this stable threat in its Risk Management program and manages this threat by limiting the polarization of the pipeline. For pipelines identified with this threat, the pipe-to-soil potentials are maintained at levels less negative than -1200 mV in order limit hydrogen production that could embrittle a hard spot. Regarding the L300A corrosion growth rate, at the one location on L300A South, ILI log distance 234884, where a corrosion growth rate of 1 mil/year corrosion was utilized, the anomaly was visually inspected and the factors contributing to metal loss were successfully mitigated by re-coating the anomaly and by on-going Cathodic Protection monitoring with recently installed remote rectifiers. PG&E's "PG&E Commentary on Soil Corrosion and Estimates for Pit Growth

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	The compliance file for Line 57B did not contain documentation of what threats, other than EC, were considered, evaluated and/or assessed on Line 57B. PG&E did not have LTIMPs for Line 2 and Line 57 because re-assessments were performed in 2008 before the LTIMP could be assembled. PG&E should have had the LTIMPs in place at least by 2007 to identify and address all other threats not assessed by the ILI run.	Rates", attached, supports the utilization of 1 mil/year "where the factors that contributed to the metal loss have been or can be successfully mitigated..." As noted in this commentary this corrosion growth rate is based on data from the book, Peabody's Control of Pipeline Corrosion, as well as studies supported by the Department of Transportation (DOT) and the National Bureau of Standards (NBS). Since this inspection was performed via ILI, the corrosion growth rate was not assigned via Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09) and Manager approval was not required for the growth rate utilized. Presently, RMP-09 documents the correlation of soil resistivity to estimated corrosion growth rate. In the next procedure revision RMP-09 will be modified to include the corrosion growth rate of 1 mpy, with the justification either included as an attachment or referenced appropriately. Even though PG&E agrees that Long Term Integrity Management Plans (LTIMP's) were not created for the initial assessments of lines 2 and 57 performed in 2001, LTIMPs were not required by PG&E's initial issuance of Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) under which these initial assessments were performed. Threats for these lines were listed in the 2004 BAP. In compliance with 49 CFR 192.921 (e), the 2001 inspections assessed for the initial time dependent threats. RMP-06 Revision 0, written in 2004, documented how each of these pipelines' threats would be addressed but did not require an LTIMP. These lines were re-assessed in 2008 and are subject to the more current revision of this procedure which requires an LTIMP to be created.
13	Referencing PHMSA Protocol B.04.a, CPUC stated: PG&E has no formal process to track and integrate new HCAs that are not part of the annual review into the BAP. The date that the HCA is discovered should be better recorded in order to confirm compliance. Finally, the USRB team had a concern that PG&E is not performing any investigations to confirm, when an HCA is newly identified, if the HCA is one that existed in 2004 (or when other reviews were performed prior to the date of discovery of the HCA) but was somehow missed. Such an investigation could help PG&E better	PG&E meets the requirements of 49 CFR §192.905(c), but we will explore areas for improvement as discussed below. In addition to the annual county by county HCA review, PG&E integrates new HCAs as follows: 1 - Risk Management Procedure-06 "Gas Transmission Integrity Management Program" section 12 requires that each change in the audit change log, that was not a result of the annual county reviews, is reviewed by a risk engineer. The risk engineer's review documents (among other things) if the change results in a new HCA.

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	validate its HCA identification process.	2 - Since HCA identification is one of the fields tracked in the audit change log (an electronic day by day record of changes to key fields in the Geographic Information System (GIS) pipeline layer), the date any new HCA is identified is documented. New HCAs are incorporated into PG&E's BAP within one year from the date they are identified, which satisfies the requirements of PHMSA Protocol B.04.a.
14	Referencing PHMSA Protocol C.01.a, CPUC stated: Protocol C.01.a.xi requires "all other potential threats" be identified and evaluated; however, PG&E has not developed a process for evaluating the threat of equipment failure and is not mandating hard spots (RMP-06, Section 3)\0 be assessed, although they have been identified, as a possible threat, before considering assessment or mitigation efforts are completed. 49 CFR §192.917(a) states in part: "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..... Per 49 CFR §192.917(c), an operator must conduct a risk assessment that considers the threats and aids in prioritizing the covered segment for the baseline and continual assessments. For equipment threats, ASME 831.8S, Section A6.2 (page 49) specifies minimal data sets to be collected and reviewed before a risk assessment can be conducted. PG&E has not collected this data set, nor attempted to identify particular equipment threats on any given segment.	PG&E meets the requirements of 49 CFR §192.917(a), [§192.917(e)(4), and ASME B31.8S-2004, Section 2.2 and Appendix A4.3, but we will clarify our procedures in response to your findings. Refer to Item No. 12 for PG&E's response regarding hard spots. Regarding equipment threats, in the next revision of Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) PG&E will clarify the current processes for identifying and evaluating equipment threats. Currently, RMP-06 specifies that equipment threat is considered to be present everywhere and is managed through PG&E's existing Operations & Maintenance procedures including: - Documenting and tracking material problem failure reports though PG&Es Material Problem Report (MPR) system and - Documenting key system events in the system event reporting log Both of these measures will be explicitly referenced in the next revision to RMP-06. In addition, the 2010 revision of the BAP will include a column for equipment threat and note its application system-wide.
15	Referencing PHMSA Protocol C.02.a, CPUC stated: PG&E has identified Equipment Failure as a threat, although it's unclear how this threat is assessed and/or if previous equipment related data has been integrated into the BAP. PG&E RMP-06, Section 2.4, mentions a procedure for determining equipment threat; however, the procedure doesn't exist according to PG&E. PG&E	Refer to Item No. 14 for PG&E's response regarding equipment threats.

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	did not integrate equipment data in BAPs established in 2004.	
16	Referencing PHMSA Protocol C.02.b, CPUC stated: It does not appear that PG&E has integrated patrolling records into its GIS.	PG&E meets the requirements of ASME B31.8S and 49 CFR §192.917(b), and our standards integrate patrol records into GIS. PG&E Standard 4127 "Class Location Determination, Compliance, and Maintenance" (See Attachment) details out the process for integrating patrolling records. This procedure requires new construction identified through patrols to be identified and communicated to the Mapping department for incorporation into GIS. Appendix C of Standard 4127 notes the requirement for notifying Mapping and copying the Integrity Management Team. Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) requires the Integrity Management team to review all notifications.
17	Referencing PHMSA Protocol C.02.f, CPUC stated: PG&E is not currently entering USA information into its GIS, nor is it entering any patrol findings that could impact transmission pipelines. (PHMSA FAQ-81 requires: "*Information related to determining the* potential for, and preventing damage due to excavation, including damage prevention activities..... be integrated in performing a continual evaluation of pipeline integrity.) PHMSA FAQ-240 (paragraph 4) also speaks to this, as well as ASME; 831.8S, Section A7.2 also requires one-call to be integrated.	PG&E meets the requirements of ASME B31.,8S and 49 CFR §192.917(e)(1). For the integration of patrol information, see PG&E's response to Item No. 16. PG&E *does not enter Underground Service Alert (USA) information into the* Geographic-Information System (GIS), however, the requirements addressed in ASME B31.8S and §192.917(e)(1) are addressed through the following: - Review of A-forms where excavation damage may have occurred - For assessments completed by External Corrosion Direct Assessment (ECDA), foreign line crossings are identified and GPS'd during Phase 1 and Phase 2 (based on current one-call required to perform work) and are considered during Phase 3 for direct examination consideration - For assessments completed by In-Line Inspection (ILI), a geometry tool is utilized for dent detection
18	Referencing PHMSA Protocol C.03.c, CPUC stated: PG&E RMP-01, Section 6.4.3, states: "The committee has determined that the factors in A through D of this section are significant for determining the reliability impact of a gas pipeline failure." However, there are only factors A through C listed under that section. PG&E RMP-01 needs to be revised to either add factor D, or indicate if only factors A through C apply.	PG&E meets the requirements of ASME B31.8S. PG&E acknowledges the typo noted by the CPUC. PG&E's Risk Management Procedure-01 "Risk Management" (RMP-01) section 6.4.3 reference to factor D is a typo and PG&E will revise to omit the reference to factor D in the next revision of this procedure.
19	Referencing PHMSA Protocol C.03.e, CPUC stated: Exception report had to be issued due to unavailability of personnel from steering committees to meet due to	PG&E meets the requirements of ASME B31.8S-2004, Section 5.7(b). Per PG&E's Risk Management Procedure-01 "Risk Management" (RMP-01), risk calculations are conducted annually as required, but there is no code or

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	other (parcel entry) work having to be done at the end of the year.	procedural requirement to annually review the algorithms used to calculate risk. In accordance with PG&E's exception process documented in Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06), the need for the risk committee meeting was reviewed and it was determined it could be deferred.
20	Referencing PHMSA Protocol C.04.a, CPUC stated: PG&E IMP Consequence Committee did not meet in 2008 or 2009. PG&E staff indicated that per PG&E RMP-06, Section 18, Exception Process allowed for the annual meeting requirement to be waived. It would appear that an annual meeting is required by code since RISK, of which consequence is one factor, has to be evaluated at least annually. PG&E believes the meetings in 2008 and 2009 were not necessary since consequences, which are driven by PIC calculations, do not significantly change. In addition, the 2009 minutes from the meeting of the PG&E IMP Ground Movement Committee did not clearly indicate that all items required to be reviewed by PG&E RMP-01, Section 6.2.5 were reviewed (I.e., LOF x COF list was unavailable during the meeting so only the LOF list was reviewed.) FAQ-234 and ASME B31.8S, Section 5.8 require annual review of RISK. Finally, a PG&E e-mail, detailing meeting minutes from the 2009 meeting of PG&E IMP External Corrosion Committee, lacks any detail or support for the decision making process used to modify PG&E RMP-02.	PG&E meets the requirements of 49 CFR §192.917(c) and ASME B31.8S-2004, Section 5.12. However, we will reaffirm with our risk committees the importance of proper documentation. Per PG&E's Risk Management Procedure-01 "Risk Management" (RMP-01), risk calculations are conducted annually as required, but there is no code or procedural requirement to annually review the algorithms used to calculate risk. Since no significant events occurred in 2008 and 2009, PG&E used the exception process documented in Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) to document that a Consequence Committee meeting wasn't needed. However, all threat committee meetings were held in 2009. During the audit, PG&E noted that the change documentation prepared for the revision to the external corrosion algorithm explained each change, the reason for that change, and the program implication of each change which we believe provides the necessary detail required by code to document the decision making process. Similar documentation was provided for the Ground Movement Committee. PG&E will reaffirm with the risk committees the importance proper documentation of the discussion and the changes that are made as a result of these meetings. PG&E will also look into whether this committee review and documentation process should be more standardized.
21	Referencing PHMSA Protocol D.02.b, CPUC stated: Pre-assessments are supposed to be performed as the first STEP in order to identify regions, tool selection, and ECDA feasibility; however, PG&E conducted a pre-assessment following other ECDA steps having commenced (example: N-Seg 177 (2008)). In addition, PG&E is conducting concurrent pre-assessment and indirect assessment activities on a routine basis (I.e., N-Seg 131, route #DREG4718, HCA segments 201 and 203) where tool selection is	PG&E meets the requirements of NACE RP0502-2002, Section 3.3. This protocol does not require sequential phases to be run, however, it does require a feasibility assessment to be conducted by integrating and analyzing the data collected. Per PG&E's Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09), the feasibility assessment is included in the pre-assessment step. The information on Form A (Data Element Check Sheet) and Form B (Sufficient Data List) are considered when completing Form C (Feasibility Analysis Report). Form C is where the data from previous forms is integrated and analyzed and the feasibility of utilizing ECDA as an assessment method is documented. Due to scheduling logistics, steps are sometimes run in

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	preordained and the feasibility of the ECDA process is forced to be a given.	parallel. However, when any information learned in the pre-assessment step questions the feasibility of performing ECDA or requires a different tool selection than typically used, changes are made to the assessment plan and documented accordingly.
22	Referencing PHMSA Protocol D.02.d, CPUC stated: PG&E groups all casings into only 2 regions -Region 3 and Region 8, in which the later region was recently added due to temperature gradient, SCC, and condensate concerns. Casings are aggregated by region and year for all segments (N-Segs) on which assessments are performed in a given year. Casing assessments are performed from an aggregated pool from which digs are then initiated. PG&E's grouping of its casings does not follow the March 1, 2010, PHMSA Guidance, "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs." The guidance developed guidelines for establishing ECDA regions for cased pipe. Six attributes required separate ECDA regions and eleven attributes must be considered when determining ECDA regions, but alone does not always require a separate ECDA region. During an April 2010 workshop, PHMSA provided additional clarification on guidance related to casing assessments and reinforced its expectation for operators to utilize the guidance in completing casings assessments by December 17, 2012. During the audit, PG&E staff stated that PG&E does not plan on utilizing the March 1, 2010, in regionalizing casings per the PHMSA Guidance. PG&E schedules Regions 1 and 2, along with 5, for excavation as indirect assessments are received, whereas other casing regions are grouped together and dug from a "pool" of potential tool dig sites. This process is not allowed for by 49 CFR §192 or NACE RP0502. (This process fails to consider CP variations and CP historical deficiencies applicable to casings on different segments.)	PG&E meets the requirements of NACE RP0502-2002, Section 3.5. It is correct that PG&E region groupings for casings do not follow the PHMSA Guidance. Although 49 CFR Part 192 and NACE RP 0502 do not speak to the assessment of casings, PG&E's casing program (which was developed in 2005) is based on the engineering report conducted by Corrpro and sponsored by PRCI. This paper lays out the technical justification for the 2 casing regions PG&E has identified. Region 8 which PG&E has defined as "Casings with Atmospheric Corrosion Threat" was further validated by the investigation and operator's root cause determination in the Beaumont, KY rupture. As an active participant in the industry task group, PG&E helped to develop the PHMSA Guidance, "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs." It was made clear during the development of these guidelines that they were to be optionally utilized by those operator's that needed further guidance on casing assessment. PG&E's casing assessments were well underway at the time of the guidance development and, therefore, PG&E has not incorporated the guidance into the procedures. On November 1, 2010, PHMSA issued updated casing assessment guidance. Within Section 2 (Purpose), PHMSA clarifies that "these guidance materials do not create legally enforceable rights or obligations and are provided to help the public understand how to comply with the regulations. Therefore, to the extent the terms "shall" and "must" and other mandatory language are used, they signify actions that are necessary for an operator to conform with this guidance, but do not constitute regulations." PG&E intends to complete its 10 year baseline assessment utilizing the current casing region designations. PG&E "pools" casing regions annually because it's about assessing for the threat of External Corrosion. This is determined by whether the casing is shorted to the pipe or not. Our casing assessment method determines whether a shorted casing exists. All shorted casings are addressed and the threat of external

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		corrosion is assessed for. The PHMSA guidance developed leads the operator to other actions in order to address other threats. If the only threat is external corrosion, it is not necessary to run additional tests. Beyond the requirements in 49 CFR Part 192 and all incorporated references, PG&E performs effectiveness digs on casings in addition to the effectiveness digs that are performed on non-cased pipelines. There is not a requirement to perform effectiveness digs per region, only at randomly selected locations based on indication, however, PG&E conducts separate effectiveness digs specifically within the casing region in order to validate the effectiveness of the casing assessment process.
23	Referencing PHMSA Protocol D.02.b, CPUC stated: PG&E RMP-09, Sections 4.3 and 4.4.3, doesn't specify the physical spacing of readings but it indicates to follow the different indirect inspection tool procedures. A copy of MEARS DCVG specified no spacing interval to be used for readings, nor did it specify any process for changing spacing due to indications.	PG&E meets the requirements of NACE RP0502-2002. It is correct that PG&E's Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09) does not specify spacing, however, Mears' current Close Interval Survey (CIS) procedure Rev 4 (See Attachment) specifies typical spacing and calls for decreased spacing when there is an indication of shallow pipe (< 24"). During coating anomaly surveys, there is no need to decrease spacing because the Direct Current Voltage Gradient (DCVG) tools can pinpoint coating holidays. Mears' testing interval is supported by their commentary white paper (See Attachment).
24	Referencing PHMSA Protocol D.03.b, CPUC stated: PG&E RMP-09 provides no direction for decreasing interval spacing when an indication is encountered.	Refer to Item No. 23 for PG&E's response.
25	Referencing PHMSA Protocol D.04.a, CPUC stated: PG&E needs to clarify RMP-09, Section 5.3.1 (page 45 of 204). It discusses a typical length of 12-feet, centered on the indication, for the purpose of exposing approximately 10-feet of pipeline for direct examination. However, it appeared from records review that only 10-foot excavations are being performed. In PG&E RMP-09, Section 5.6, Table 5.6.4, the Data Elements 1.9 & 1.10 are found in the table as being "Required". However, those Data Elements are not found in the "Direct Examination Data Sheet (Casing Only) Page 1 of 1, Form H. In PG&E RMP-09, Section 5.3.3.1, Table 5.3.1 states that PG&E is conducting just one addition dig if there	PG&E meets the requirements of NACE RP0502-2002, but we understand your concerns and are revising our forms to address your concerns. Regarding excavation length, 12 foot excavations are required in order to achieve a 10 foot inspection length per PG&E's Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09). PG&E does not know which specific H-forms were a concern to the CPUC since they are not specifically mentioned, however, PG&E reviewed all the binders provided during the audit and confirmed that 10 foot inspection lengths were performed. PG&E understands the CPUC's concern and believes that the H-form fields used to document excavation length and inspection length are unclear and need to be improved to more clearly document the length of pipe being inspected. This will be addressed in the next revision of the H-form.

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	was an immediate and schedule found and not the addition two digs for the first time through as required in NACE RP0502, Section 5.10.2.2.2 and PG&E RMP-09, Section 5.3.3.1. Example in PG&E RMP-09 shows how PG&E interprets' NACE RP0502, Section 5.10.2.2.2. In PG&E RMP-09, Section 5.3.2.1, it states in part that PG&E does reprioritize even immediate digs after sampling "some" immediate indications. PG&E is not following NACE RP0502 requirement to dig ALL immediate indications and to not reprioritize indications the first time ECDA is applied to a given segment. PG&E presented a white paper that essentially considers "should" from the NACE RP0502 document as a suggestion and not requirement.	Regarding the "required" data elements RMP-09, Section 5.6, Table 5.6.4, PG&E agrees that they were not listed on the casing form H. This oversight in the published procedure was rectified during the audit and a revised version of the casing form H that incorporates the missing data elements was provided to the audit team. Regarding the additional digs when conducting ECDA for the first time, it has been PG&E's practice to perform the additional two digs when ECDA is used for the first time on a pipeline. Nevertheless, RMP-09, Section 5.3.3.1, Table 5.3.1 will be revised to add clarity around PG&E's compliance with the direct examination requirements of NACE RP0502 in the next revision of this procedure. Regarding the re-prioritization of "immediates", please see PG&E's response to Item No. 27.
26	Referencing PHMSA Protocol D.04.b, CPUC stated: PG&E RMP-09, Section 5.7, and all related forms need to be modified to mandate a 10% pressure reduction, as required by PG&E Utility Operation Standards 4134, if mechanical damage is found during the direct examination process.	PG&E meets the requirements of 49 CFR §192.933. §192.925(b)(3)(ii), §192.933, and NACE RP0502-2002, Section 5.5, but we will refine the language in the next revision of the procedure to address your concerns. Although the pressure reduction requirement is addressed within PG&E's Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment", the language does not clearly indicate this as a requirement. The next revision of this procedure will mandate a 10% pressure reduction for mechanical damage to align with PG&E's Standard S4134 "Selection of Steel Gas Pipeline Repair Methods" (See Attachment).
27	Referencing PHMSA Protocol D.04.f, CPUC stated: PG&E presented a "MEMO TO FILE", dated May 20,2010, in which it allows for reclassification or re-prioritization of indications, regardless if assessment is performed the first time or subsequent assessment. This goes against NACE RP 0502 (2002) which discourages such a practice. Also, PG&E's definition of first time application of ECDA is inconsistent with NACE 0502, Section 5.8.4.2 which discusses "initial ECDA" vs. PG&E's "first time ECDA is used." It should also be noted that the May 20, 2010 memo, which was created during the audit, could not retroactively apply to any reprioritizations performed prior to its creation	PG&E meets the requirements of NACE RP0502-2002, Section 5.9 and 49 CFR §192.925(b)(3)(iv). As explained in the "MEMO TO FILE", NACE RP0502 Section 5.8.4.2 states " ...For initial ECDA applications, the pipeline operator should not downgrade any classification or prioritization criteria". NACE RP0502 also indicates "the term should is used to state something considered good and is recommended but is not mandatory". As stated above in response to item 25, PG&E applies reprioritization in accordance with NACE RP0502 on the basis of pipe condition. NACE RP0502 Section 5.10.2.1 states "All indications that are prioritized as immediate require direct examination". PG&E does plan to dig all indications that are prioritized as Immediates. This plan is updated based on evidence received

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	since justification had not been provided for such reprioritizations.	through the Direct Examination phase where the actual pipe condition is determined and the prioritization of the indication is verified. Since Immediate indications are not necessarily Immediate conditions, the excavation of the indication determines if an immediate condition exists on the pipe. The Immediate Indications are excavated in priority based on likelihood of corrosion and, if during these excavations, the pipe does not reflect an Immediate condition, then the excavation plan is altered and reprioritization is performed on the basis of pipe condition which may reprioritize to scheduled indications. PG&E believes this process fully complies with NACE RP0502 Section 5.10.2.1.1 which states "The need to conduct direct examinations of indications that are reprioritized from immediate to scheduled may follow the guidelines for scheduled indications." NACE RP0502 does not define "initial ECDA" or "the first time ECDA is used". Since the concept is not clearly defined within the RP document, per PG&E's Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09), PG&E has defined "first time" as "the first time the ECDA methodology is used to assess the integrity of all or part of N-seg (numbered segment)".
28	Referencing PHMSA Protocol D.04.g, CPUC stated: PG&E did not have a written process which clarifies the criteria and internal notification procedures for any changes in the ECDA Plan as required by the protocol.	PG&E meets the requirements of 49 CFR §192.925(b)(3)(iii), §192.909, and §192.911(k), but agrees that aspects of how we comply are not well documented. PG&E concurs that the internal notification processes currently utilized should be documented in Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09). The next revision to this procedure will document the internal notification process for any changes in the ECDA plan.
29	Referencing PHMSA Protocol D.05.c, CPUC stated: PG&E provided a copy of a "MEMO TO FILE", dated December 23, 2009, in which the company allows the random effectiveness direct examination location to be chosen from established data sets that contain possible third party damage, possible old corrosion, or other indications that will verify the successfulness of the EGDA process. The memo restates the definition of "Random" as contained in PG&E RMP-09 (Rev 7) as being "Statistics relating or belonging to a set in	PG&E meets the requirements of NACE RP0502-2002. PG&E agrees that NACE RP0502 Section 6.4.2 requires "at least one additional direct examination at a randomly selected location shall be conducted...". However, Section 6.4.2.1 provides further instruction for the random excavation by requiring that "..the direct examinations shall be conducted at randomly selected locations, one of which is categorized as a scheduled (or monitored if no scheduled indications exists) and one in an area where no indication was detected". Since NACE RP0502 requires an examination to be performed at a pre-determined indication severity, PG&E's Risk Management Procedure-09

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	which all members have the same probability of occurrence..."It provides as examples of sets of indications such as Scheduled, Monitor, etc. However, another definition (per Encarta Dictionary) defines "random" as: "done, chosen, or occurring without an identifiable pattern, plan, system, or connection.". The USRB team believes PG&E's process for selecting a random confirmation dig conflicts with NAGE RP0502, Section 6.4.2 which states in part, "At least one additional direct examination at a randomly (emphasis added) selected location shall be conducted to provide additional confirmation that the EGDA process has been successful." Since PG&E's selection process, for selecting locations for determining the effectiveness of its DA process, utilizes established data sets of third party damage or old corrosion to guide in the selection locations, the USRB teams believes it constitutes an identifiable pattern, plan, or system..."which does not provide for a truly random selection process".	"Procedure for External Corrosion Direct Assessment" documents the process of selecting a random location in alignment with the additional guidance provided in Section 6.4.2.1.
30	Referencing PHMSA Protocol D.06.a, CPUC stated: During our audit, we were unable to confirm if the Supervising Engineer, the ICDA Project Manager, and the ICDA Project Engineer had received formal training as required by RMP-10, Sections 2.3.2, 2.3.3., and 2.3.4, respectively.	PG&E meets the requirements of 49 CFR §192.927(c), although we acknowledge that individuals had not yet received formal training at the time of the audit. Because the document was in a framework format and had not been finalized until April 2010, the individuals had not yet received formal training (in the form of an annual review) on the Internal Corrosion Direct Assessment (ICDA) procedure. However, the creation of the issued document was led by an industry consultant and two PG&E employees with NACE Internal Corrosion training. The ICDA procedure has been issued and annual reviews will occur starting in 2011.
31	Referencing PHMSA Protocol D.06.b, CPUC stated: PG&E RMP-10 does not have an explicit requirement that the ICDA be carried out on the entire pipeline in which covered segments are present. (49 CFR §192.927).	PG&E meets the requirements of 49 CFR §192.927(c)(5)(iii), but agrees it is not well documented. The intent and application of PG&E's Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment" (RMP-10) is to carry out ICDA on the entire pipeline, but PG&E agrees this is not explicitly stated. This will be clarified on the next revision of RMP-10.

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32	Referencing PHMSA Protocol D.07.a, CPUC stated: In PG&E RMP-10, Section 4.2.4.2, instead of consider supplementing USGS data if inaccurate data is available, this step needs to be made mandatory if inaccurate data is available. Modify PG&E RMP-10, Section 4.3.3 and other "may"; "could", etc. statements to be more definitive. PG&E RMP-10, Section 4.4.1 needs to clearly define what is considered as "sufficient" data. Also, Section 4.3.3, only provides for recommended attendees for the pre-assessment review meeting; however, we believe this section needs to specify required attendees essential to the purpose of the meeting.	PG&E meets the requirements of 49 CFR §192.927(c)(5)(i), although PG&E agrees with the CPUC that this procedure could be improved. Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment" contains all of the necessary code requirements. However, PG&E acknowledges the CPUC's observation that this procedure could be strengthened by using definitive statements. Based on the CPUC's feedback, on the next revision of this procedure, PG&E will review the Sections specifically referenced in this finding and make the necessary edits. .
33	Referencing PHMSA Protocol D.08.a, CPUC stated: In PG&E RMP-10, Section 6.2.3, "pipeline operator" needs to be made specific to PG&E personnel responsible. PG&E RMP-10, Section 6.2.3.1: We believe this section is intended to reference 5.5.9 instead of 5.5.10. PG&E RMP-10, Section 6.2.5 needs to provide more direction as to how many, and at what locations, additional direct examinations could be performed.	PG&E meets the requirements of 49 CFR §192.927(c)(5)(i), but agrees this procedure can be improved. PG&E agrees that Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment" (RMP-10) needs to be made specific to PG&E personnel. The procedural framework was developed in the 2005-2006 timeframe with the help of an industry consultant. Based on the CPUC's feedback, PG&E will change any "pipeline operator" references to specifically reference PG&E in the next revision of the procedure. PG&E agrees that the RMP-10 references within Section 6.2.3.1 need to be updated. This change will be made in the next revision of the procedure. Regarding Section 6.2.5 needing to provide more direction for additional direct examinations, PG&E addresses all required 49 CFR Part 192 and ASME B31.S requirements for selecting direct examinations.
34	Referencing PHMSA Protocol D.08.e, CPUC stated: PG&E indicated it is performing GWUT to inspect non-exposed pipe wall during direct examinations; however, in PG&E RMP-10, Section 6.3.7, this GWUT is stated as something that "may" be done to augment the direct examination process. The "may" needs to be removed from the section and replaced as a requirement.	PG&E meets the requirements of 49 CFR §192.927(c)(5)(ii). There is no requirement to specifically use Guided Wave Ultrasonic Testing (GWUT) during the direct examination. As stated in PG&E's Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment" (RMP-10), other technologies can be used in lieu of GWUT. For example, either liquids analysis or GWUT could be used as the more restrictive criteria when conducting ICDA for the first time.
35	Referencing PHMSA Protocol D.09.b, CPUC stated:	PG&E agrees that since the ASME B31.8S document is incorporated by

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	PG&E RMP-10, Section 7.3.4, replace "should" with the word shall since these are performance measures required by ASME 831.8S.	reference into the code, the performance measures listed in Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment" Section 7.3.4 need to reflect mandatory, not suggested, language. This change will be made on the next revision to RMP-10.
36	Referencing PHMSA Protocol D.09.c, CPUC stated: PG&E RMP-10, Section 7.2.2 needs to provide more detail on determining the frequency for monitoring of the conditions listed, as well as who will make that determination. Also, what constitutes "periodically" in the drawing of liquid samples from low points.	PG&E meets the requirements of 49 CFR §192.927(c)(4)(ii). The procedural framework was developed in 2005-2006 time frame with the help of an industry consultant and the term "periodically" was incorporated into Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment" to allow for the flexibility to respond to site specific conditions. The term "periodically" also matches the language used within §192.927 (c)(4)(ii).
37	Referencing PHMSA Protocol D.09.d, CPUC stated: PG&E has assumed corrosion of 20% wall, even at locations where none has been found, compared that to the length of time the pipeline has been in operation, and then used that data to calculate remaining Yz life. Although PG&E indicated it is doing this step, it is not written out as a requirement within PG&E RMP-10.	PG&E meets the requirements of 49 CFR §192.927(c)(5)(ii). However, PG&E agrees this assumption can be improved in the procedure. PG&E will include language to this effect in the next revision of Risk Management Procedure-10 "Procedure for Dry Gas Internal Corrosion Direct Assessment".
38	Referencing PHMSA Protocol D.11.a, CPUC stated: PG&E RMP-13 does not detail the requirement of ASME B31.8S related to missing data; (D.11.a. iii) requires segments to be prioritized higher or conservative assumptions to be used.	PG&E meets the requirements of 49 CFR §192.929(b)(1). However, PG&E agrees that this can be improved in the procedure. Although it is PG&E's practice to utilize conservative assumptions when data is missing, PG&E will clarify this requirement in the next revision of Risk Management Procedure-13 "Procedures for Stress Corrosion Cracking Direct Assessment" (RMP-13).
39	Referencing PHMSA Protocol D.12.b, CPUC stated: PG&E RMP-13 does not explicitly require the hydrostatic test required by ASME B31.8S, Appendix A3.4.	PG&E meets the requirements of ASME B31.8S, but PG&E agrees the procedure can be made more explicit. The ASME B31.8S document requires a hydro-test only if Stress Corrosion Cracking (SCC) is found to have caused a leak or rupture. Since there hasn't been a leak or rupture caused by SCC within PG&E's system, a hydro test is not required to complete the SCC assessments. Additionally, in every excavation conducted within the Integrity Management program, PG&E requires a magnetic particle examination on the entire length of the exposed pipeline to look for the presence of SCC, which is not a requirement. While we are in full compliance with 49 CFR Part 192 and all incorporated documents, we will add language to clarify this in the next revision of Risk Management Procedure-13 "Procedures for Stress Corrosion Cracking Direct Assessment".
40	Referencing PHMSA Protocol E.01.a, CPUC stated:	PG&E meets the requirements of 49 CFR §192.933(b), but PG&E agrees the

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	PG&E RMP-06, Section 6.4 has to be made PG&E-specific and detail what PG&E defines as its discovery date. Also, PG&E RMP-06 provides no "discovery of condition" definition for ICDA.	procedures can be improved and made more explicit. The requirements for definition of discovery are contained in PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06), Section 6.4. Based on the CPUC's feedback, PG&E will remove the term ""an operator" to make the language PG&E specific. Additionally, PG&E will add a "discovery of condition" for ICDA which will be the same definition as the one documented for ECDA. These changes will be reflected in the next revision of RMP-06.
41	Referencing PHMSA Protocol E.01.b, CPUC stated: PG&E RMP-11 does not have an explicit requirement to document the date of discovery using whichever form PG&E may dedicate for the documentation. The same concern applies to PG&E RMP-09 which also does not have an explicit requirement.	PG&E does have a requirement to document the date of discovery per the requirement of 49 CFR §192.933(b), however, the requirement is inconsistent among procedures. Based on the CPUC's feedback, PG&E will update Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09) and Risk Management Procedure-11 "In-Line Inspections" (RMP-11) during the next revision to require the documentation of "Discovery Date". For In-Line inspection, RMP-11, Form F will be revised to include a line for "Discovery Date" in place of "PG&E Notification Date" and a specific requirement to document this date on Form F will be added to a newly created section entitled "Immediate Anomaly Discovery". For Direct Assessment, in the next revision of RMP-09, the change will be made to specify that the "Inspection Date" on the H-form is the "Discovery Date".
42	Referencing PHMSA Protocol E.02.a, CPUC stated: Although PG&E RMP-11, Section 5.3.3 speaks to reducing pressure to address a safety issue on the line due to an immediate condition; however, the option to shut down the line, or under what situations scenarios the line would be shut-down, is not addressed by the RMP.	PG&E procedures do contain requirements on what to do when a safety issue due to an immediate condition is found per the requirements of 49 CFR §192.933(d)(1). However, the requirement is inconsistent among procedures and there is not clear guidance on the consideration of shutting down the line. Even though it is PG&E's practice to consider shutting down a line if a safety conditions warrants it, based on the CPUC's feedback, PG&E's Risk Management Procedure-11 "In-Line Inspections" and Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" will be updated on the next revision to explicitly add this option in the event an immediate condition is reported or discovered.
43	Referencing PHMSA Protocol E.02.c, CPUC stated: PG&E RMP-11, Section 5.5, does not provide for requirements to record and monitor anomalies classified as "monitored conditions" during subsequent	PG&E meets the requirements of 49 CFR §192.933(d)(3). It is PG&E's practice to monitor anomalies classified as "monitored conditions". Risk Management Procedure-11 "In-Line Inspections" Section 5.5.2 requires that

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	risk or integrity assessments for any changes in their status that would require remediation.	"Monitored" anomalies "must be recorded and compared to themselves during future re-inspections".
44	Referencing PHMSA Protocol E.03.a, CPUC stated: In PG&E RMP-11, Section 5.3.3, PG&E uses the highest operating pressure, occurring anytime between the time period the pig run is made and the time a pressure reduction is determined as the pressure from which a 20% reduction is made. This does not comply with reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. A provision in 49 CFR §192.933 exists to address circumstances under which a 20% reduction cannot be taken. 49 CFR §192.933 states in part: "An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State."	PG&E meets the 49 CFR §192.933(a) pressure reduction requirement based on the PHMSA FAQ-67 (see attached) which states that "the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present (ie. pressures for which safety has been demonstrated)." Since the anomaly has safely experienced the pressures from the time of the ILI run to the time the anomaly is reported, PG&E has been using the highest operating pressure during this time period. Although PG&E has been in compliance with the requirements, PG&E understands the CPUC's concern and has made a decision to redefine "Discovery Pressure". Based on CPUC's feedback, PG&E agrees that it should redefine "Discovery Pressure" as it relates to potential defects found through In-Line Inspection. In next revision of PG&E's Risk Management Procedure-11 "In-Line Inspections" (RMP-11) Section 5.3.3.1. PG&E will redefine "Discovery Pressure" to be the pressure at the time the Immediate anomaly was seen by the inspection tool.
45	Referencing PHMSA Protocol E.03.b, CPUC stated: PG&E needs to make it clear in RMP-09, Section 7 and PG&E RMP-11, Section 7 that the basis for why public safety will not be jeopardized needs to be documented when evaluation and remediation activity cannot be completed within established timeframe requirements. Form M, from PG&E RMP-11 has the field to document this requirement.	PG&E does have a requirement to document the justification, when a remediation activity cannot be completed, which includes why public safety will not be jeopardized per the requirements of 49 CFR §192.933(a) and §192.933(c). However, the requirements in the procedures and the forms will be updated for clarity and consistency. Based on the CPUC's feedback, Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09) and Risk Management Procedure-11 "In-Line Inspections" (RMP-11) will be revised to clearly and consistently define the specific requirement to document the technical basis confirming that delaying the evaluation and remediation beyond the required timeframes do not compromise public safety. During the next revision of these procedure, PG&E will make the following changes: RMP 11, Section 7.1 - Add a bullet point requiring all Form M Exception Reports

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		to document technical justification that public safety is not jeopardized. This has been PG&E's standard practice and the field is already contained within RMP-11's Form M but the change will proceduralize the requirement. RMP-09 - Update Form M to match RMP-11's Form M and revise the procedure to require documentation on the Form M.
46	Referencing PHMSA Protocol E.04.a, CPUC stated: PG&E RMP-09 requires that the first excavation commence within 180 days of the assessment. It is the goal of 49 CFR §192.933(b) to have discovery of all potentially unsafe conditions from the assessment/re-assessment occur within 180 days and not just the have the first dig take place within 180 days. 49 CFR §192.933 states in part: "... An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination..."	PG&E meets the requirements of 49 CFR §192.933(c) and §192.933(d). 49 CFR §192.933 (b) states "An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make (the) determination" about any condition that presents as potential threat to the integrity of the pipeline. For ECDA, while conducting an integrity assessment, all indications of potential threats to the integrity of the pipeline are excavated during phase 3 (Direct Examination). At the end of Phase 3, which constitutes the completion of an integrity assessment, all conditions that present a potential threat have been addressed while exposing and inspecting the pipe. Therefore, PG&E always obtains the sufficient information required under §192.933 (b) well in advance of 180 days after conducting an integrity assessment.
47	Referencing PHMSA Protocol E.04.b, CPUC stated: RMP-09 gives the contractor 90 days to provide PG&E the results of the indirect examination. PG&E performs its analysis of the indications within 1 month after receipt of data. PG&E then has 180 days from the receipt of the indirect inspection report to perform its first excavation. This process sums up to about 270 days from the completion of the indirect inspection. This does not meet 49 CFR § 192.933(b) which requires that, within 180 days after conducting an integrity assessment, the operator makes a determination if a condition presents a potential threat.	Refer to Item No. 46 for PG&E's response.
48	Referencing PHMSA Protocol E.04.c, CPUC stated: Although PG&E RMP-09, Section 5.3.1states that a 12-footexcavation, centered on the anomaly, is the length of the typical excavation performed. PG&E RMP-09, Form H documents indicate planned/actual excavations to be 10-feet in length. This leaves little buffer for GPS inaccuracies even when sub-meter	PG&E meets the requirements of 49 CFR §192.933(a). However, PG&E understands the CPUC's concern regarding the consideration of GPS inaccuracies when determining excavation location. In the next revision of Risk Management Procedure-09 "Procedure for External Corrosion Direct Assessment" (RMP-09), PG&E will modify Section 5.3.1 to document how excavation lengths will be handled to account for GPS inaccuracies.

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	GPS is used.	
49	Referencing PHMSA Protocol E.04.e, CPUC stated: Under exception report of December 11, 2008, generated by PG&E for N-Seg 101-2008 (Sta 117+36), PG&E did not dig all immediate indications from M.P. 42.24 to 44.61, PG&E examined 4 of the 7 immediate excavations specified by the ECDA IiT. PG&E's exception report stated that enough information had been gained from the examination of the 4 indications that the remaining 3 immediate indications did not need to be examined. However, this does not comply with ASME, 831.8S-2004, Section 7, or 49 CFR, §192.933(d)(1). This finding serves as one example where the USRB team found PG&E to be non-compliant with this protocol. However, based on the copy of PG&E's May 20, 2010 memo, PG&E Justification of Reprioritization for First Time ECOA, provided to the team during the audit, the team believes there are potentially more instances in which PG&E may not have evaluated or remediated immediate indications in full compliance with ASME, 831.8S-2004, Section 7, or 49 CFR, §192.933(d)(1).	PG&E meets the requirements of ASME B31.8S Section 7 and 49 CFR, §192.933(d)(1). Regarding the exception report for N-Seg 101-2008, NACE RP0502 Section 5.8 entitled "In-Process Evaluation" states "If the corrosion activity is less severe than classified, the pipeline operator may reassess and adjust the criteria used to define the severity of all indications." In the specific example the CPUC cites on N-Seg 101 assessed in 2008, this in-process evaluation and reclassification of the remaining indications was done in accordance with NACE RP0502. This integrity assessment on N-Seg 101 was not the first time or the initial application of ECDA to this line and, therefore, the memo (Justification of Reprioritization for First Time ECDA) does not apply.
50	Referencing PHMSA Protocol F.01.b, CPUC stated: Risk not evaluated in 2009 since the committees didn't meet.	PG&E meets the requirements of 49 CFR §192.937(b). Risk calculations are conducted annually as required and the results are documented in the annual revisions to the Baseline Assessment Plan. There is no code requirement for risk committees to meet annually. PG&E's procedures require annual meetings but exceptions are allowed if documented through the exception process.
51	Referencing PHMSA Protocol F.01.d, CPUC stated: PG&E performs an annual risk review for every segment, covered and non-covered, to reassess risk. Risk not evaluated in 2009 since the committees didn't meet.	Refer to Item No.50 for PG&E's response.
52	Referencing PHMSA Protocol H.02.a, CPUC stated: PG&E is performing Gas Event and Near Hit Reporting (WP1465-02) to perform root cause analysis of all excavation related damages (distribution and transmission) to improve damage prevention efforts.	PG&E meets the requirements of 49 CFR §192.935(b)(1). To ensure clarity, Work Procedure 4412-05 Section 5.B. (See Attachment) will be updated during its next revision to state that excavations or above ground surveys will be performed when evidence of unmonitored encroachment is found within "2 feet of the outer most edge of the pipeline". In addition, the instructions for Form 62-

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	PG&E's procedure for performing excavations, or above ground surveys when evidence of unmonitored encroachment are found (WP4412-05, Section 5.B.) needs to clearly state that the "2 feet of the underground facility... "means 2-feet of the outermost edge of the pipeline. Also, the instructions for Form 62-4060 do not explicitly require that the form be submitted to 1M staff If an excavation is performed to examine potential encroachment in an HCA and, possibly, on any locations not in HCAs.	4060 (A-Form - See Attachment) will be updated during the next revision to explicitly require that the form be submitted to Integrity Management "if an excavation is performed to examine potential encroachment in an HCA and, possibly on any locations not in HCAs".
53	Referencing PHMSA Protocol H.05.a, CPUC stated: PG&E uses its RMI-04 and RMI-04A to determine "triggers" that would initiate a review of segments susceptible to outside force following heavy rain or g-force events. However, there appears to be no process for initiating additional patrols prior to the triggers occurring (i.e., for locations that may require more patrols than routinely required by 49 CFR §192). PG&E stated it actively works to relocate sections located within known earthquake crossings. The processes seem to address a response to an event; however, the process does not address what is done to increase patrols that may be conducted, for P&M, for existing known threats of outside force.	PG&E meets the requirements of 49 CFR §192.935(b)(2). PG&E does have specific provisions for additional patrols, not only in response to an event or "trigger", but also to address existing known threats in the absence of a trigger. Work Procedure TD-4412P-07 (Patrolling Pipelines and Mains - See Attachment) Section 8.3 states: "Conduct additional patrols, as local conditions warrant, based on the following circumstances: Earthquakes, Landslides, Fires, Heavy rainstorms or extended rainfall, Train derailment near a pipeline right-of-way, and other disasters". Additionally, this Work Procedure requires quarterly aerial and foot patrol of all transmission lines (covered and non-covered segments), which is more stringent than the semi-annual requirement of 49 CFR Part 192.705. The procedure provides specific instructions to the surveyor on conditions to observe and report related to any outside force damage that may be found.
54	Referencing PHMSA Protocol H.07.a, CPUC stated: PG&E has not developed specific guidelines (especially none which consider items listed under H.07.a.) for utilizing in-line valves (although PG&E RMP-06 indicated this was to have been done by 12/31/2009) for pipeline integrity management. PG&E staff could provide no response why the guidelines were not completed by that date.	PG&E meets the requirements of 49 CFR §192.935(c). The requirement is for an operator to have an adequate risk analysis-based process to determine if automatic shut-off valves or remote control valves should be added. [§192.935(c)]. This risk analysis is documented in a June 14, 2006 Memo To File entitled "ASV & RCV Consideration Guideline" which was provided to the CPUC during the audit. Regarding the date "12/31/2009" in Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06), PG&E will remove this note in the next revision of the procedure.
55	Referencing PHMSA Protocol H.08.a, CPUC stated: PG&E stated that IM personnel consider P&M measures input from field staff through the pre-	PG&E meets the requirements of 49 CFR §192.935(a). The requirement is that a systematic, documented decision-making process be in place to decide which measures are to be implemented, involving input from relevant parts of the

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	assessment (field interview) stage as well as at the tail end LTIMP meeting. However, there is no written formal process for this nor does anything state who has to be part of the LTIMP review team. The LTIMPs reviewed also provided no details as to how specific P&M measures were considered to address threats to each covered segment included in the LTIMP.	organization such as operations, maintenance, engineering, and corrosion control. That process is documented in Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) section 9 and the participants in each LTIMP are documented as part of the LTIMP.
56	Referencing PHMSA Protocol H.08.c, CPUC stated: Schedules appear to be extended from year to year without clear basis of why.	PG&E meets all requirements of 49 CFR §192.935(a). Additional mitigative measures are identified and documented in the LTIMP for the pipeline being reviewed. The LTIMP is updated to document the implementation or schedule for implementation. In addition, the additional mitigative measures are tracked in PG&E's Integrity Management Assessment Computer System (IMACS).
57	Referencing PHMSA Protocol I.02.a, CPUC stated: PG&E counts mileage as being assessed at the end of the completion of direct examinations; however, per PHMSA FAQ-34, mileage is to be assessed at the conclusion of the "the last direct examination associated with direct assessment is made..." This would mean that PG&E needs to count mileage as completed after validation digs are performed, and not the last dig performed as part of the Phase 2 step of direct assessment. This is also consistent with NACE RP-0502, Section 6.4.2, which considers the direct examination dig, for process validation, to be the last examination associated with the direct assessment process.	Refer to Item No. 11 for PG&E's response.
58	Referencing PHMSA Protocol J.01.a, CPUC stated: PG&E could not provide records to show that its steering committees are meeting on an annual basis, as required by PG&E RMP-01, Section 6.2 and PG&E RMP-06, Section 3.4. No meeting minutes from 2007 were provided. In addition, PG&E's records process needs to provide more detail/rational supporting decisions made through the meetings and confirmation that the meetings are conducted, and records reviewed per PG&E RMP-01. [EC meeting minutes (07/08/2009 e-mail from Kevin Armato) is an example	PG&E meets the requirements of 49 CFR §192.947(d), but PG&E will reaffirm the importance of the risk committee meetings and investigate whether the process should be more standardized. Per PG&E's Risk Management Procedure-01 "Risk Management" (RMP-01), risk calculations are conducted annually as required, but there is no code or procedural requirement to annually review the algorithms used to calculate risk. Since no significant events occurred in 2008 and 2009, PG&E used the exception process documented in Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) to document that a Consequence committee meeting wasn't needed. However, all threat committee meetings were

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	of this.]	held in 2009. During the audit, PG&E discussed the change documentation prepared for the revision to the external corrosion algorithm (see attached) which explained each change, the reason for that change, and the program implication of each change which we believe provides the necessary detail required by code to document the decision making process. Similar documentation was provided for the Ground Movement Committee (See Attachment). PG&E will reaffirm with the risk committees the importance proper documentation of the discussion and the changes that are made as a result of these meetings. PG&E will also look into whether this committee review and documentation process should be more standardized.
59	Referencing PHMSA Protocol K.01.a, CPUC stated: PG&E ICDA performed in 2005 and 2007 was done under a draft (framework) procedure. The approval of a new procedure didn't occur until late 2009 early 2010.	PG&E meets the requirements of 49 CFR §192.909(a). The 2005 and 2007 ICDA assessments were performed under a framework procedure which is allowed for under Subpart O. 49 CFR Part 192.907 specifies that the "integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element...The framework will evolve into a more detailed and comprehensive program.". This issue is also addressed within 49 CFR Part 192.911 which states "An operator's initial integrity management program begins with a framework and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program".
60	Referencing PHMSA Protocol K.02.c, CPUC stated: There is no written process for communicating changes to vendors (I.e., MEARS) and what follow-up is reviewed to confirm that the changes were properly implemented by the vendor. Time limitations need to also be specified to make certain that changes are communicated well in advance of the expected date when changes are to be put into effect.	PG&E does have a Management of Change Plan as required by ASME B31.8S-2004, Section 12.2 (b)(3). However, PG&E agrees that while changes to the affected parties are being communicated per the requirements, no written process exists for communicating these changes. To ensure clarity and consistent application, PG&E will revise procedures to explicitly document this communication and review process in the next revisions of the effected procedures.
61	Referencing PHMSA Protocol L.01.b, CPUC stated: In Year 2007, PG&E had a review performed by P-PIC; however, it appears that PG&E did not review the report from P-PIC, and formulate a position/response on its findings, until December 2009 (Rev7 to PG&E RMP-09 mentioned on page 10 of PG&E response). In	PG&E meets the requirements of ASME B31.8S-2004, Section 12.2 (b)(7). PG&E is continually improving its IMP program and implementing internal/external audit recommendations is a key part continuous improvement. PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) does require regular audits on the IM program. However, it does not provide clear direction regarding a formal response. The

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	October 2009, PG&E had an external review done of its III and DA but as of the time of the PUC Audit, PG&E had not formulated a position/response on that review's findings. PG&E needs to review the recommendations and act on them in a timely manner.	CPUC's concern regarding the timely documentation of a response to the external reviews performed by consultants in 2007 and 2009 are legitimate. RMP-06 will be updated during the next revision to bring more clarity and rigor to Section 13.8. Additionally, all corrective actions resulting from future audits will be tracked via PG&E's commitment tracking process that is managed by PG&E Gas Engineering Regulatory Support.
62	Referencing PHMSA Protocol L.01.c, CPUC stated: There is no formal process created to document and monitor the effectiveness of corrective actions taken to improve the integrity management program. PG&E essentially considers the change form for PG&E RMP-06 as being the documentation for effectiveness; however, there are no other details as to what exactly was looked at during each annual process to review PG&E RMP-06. Also, no timetables are specified for the changes/reviews of the effectiveness.	PG&E meets the requirements of ASME B31.8S-2004, Section 12.2(b)(7). As noted by the auditors, PG&E believes the change forms (See Attachment) prepared for Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) meet B31.8S requirements to document corrective actions taken to improve the integrity management program and quality assurance processes. As required by RMP-06, these change forms document what was changed in the program, the reason for the change and the program implications of the change. PG&E believes the documented annual audits of the program and key personnel's' annual review of RMP-06 meet the requirements of ASME B31.8S 2004, Section 12.2 (b)(3) to monitor program effectiveness since there are no specified timelines.
63	Referencing PHMSA Protocol L.02.b, CPUC stated: PG&E receives OQ records for all MEARS personnel prior to their performing a covered task. ASME B31.8S, Section 12.2(b)(4) states in part: "the personnel involved in the integrity management program shall be competent, aware of the program and all of its activities, and be qualified to execute the activities within the program. Documentation of such competence, awareness, and qualification, and the processes for their achievement (emphasis added), shall be part of the quality control plan." Based on review of records for , PG&E does not appear to have a written process (I.e., priority of training, specific timetables for training, etc.). Although training requirements are mentioned in various RMPs, we were uncertain, and unable to clearly confirm how and when the training is being provided.	PG&E's various IMP procedures do contain the criteria qualifications per the requirements of 49 CFR §192.915(b). Regarding the requirements of ASME B31.8S Section 12.2 (b)(4), specifically the processes for achievement, PG&E agrees that it can clarify the written process to more clearly delineate training requirements for personnel. In the next procedure revisions, PG&E will include this documentation. The revision will specify the required training, frequency and documentation.
64	Referencing PHMSA Protocol L.03.c, CPUC stated: PG&E did provide a white paper for a "should" related to its reprioritizing of indications, including immediate indications, on any assessment first time or not.	Refer to Item No. 27 for PG&E's response.

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	However, this paper was only put to file on May 20, 2010. PG&E stated there are similar documented justifications included for its various RMPs.	
65	Referencing PHMSA Protocol M.01.b, CPUC stated: PG&E RMP-06 requires company wide e-mails, from VP of Gas Transmission and Distribution, to be distributed informing transmission staff about IM activities; however, in 2008 (PG&E exception report generated) and in 2009 (no PG&E exception report generated) no company wide e-mail was sent to staff. USRB advised that PG&E RMP-06, Section 14.6 be more detailed to add other activities that currently were stated by PG&E staff as being performed, but don't appear to be captured under PG&E RMP-06, Section 14.6 (i.e., program metrics provided to senior management).	PG&E's Risk Management Procedure-06 "Gas Transmission Integrity Management Program" (RMP-06) includes the ASME B31.8S requirement for an internal organizational communication to establish understanding and support of the integrity management program. It is correct that these communications were not generated in 2008 or 2009. PG&E has already issued the 2010 communication (see attached) and will continue to distribute these communications on an annual basis in the future.