Attachment B

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

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

December 17, 2013

GA2012-12

Ms. Jane Yura, Vice President
Pacific Gas and Electric Company
Gas Operations – Standards and Policies
6121 Bollinger Canyon Road, Office # 4460A
San Ramon, CA 94583

Subject: Transmission Integrity Management Program Audit

Dear Ms. Yura:

On behalf of the Safety and Enforcement Division (SED), of the California Public Utilities Commission (Commission), Aimee Cauguiran, Alin Podoreanu, Banu Acimis; and Pipeline and Hazardous Materials Safety Administration representative Chris McLaren conducted an audit of Pacific Gas and Electric Company's (PG&E) Transmission Integrity Management Program (TIMP) from August 27 through 31, 2012 and from September 10 through 14, 2012. The audit consisted of an evaluation of PG&E's Risk Management Procedures and related records.

A Summary of Audit Findings, which contains probable violations and concerns and recommendations identified during SED's audit, is included as an attachment to this letter.

Please provide a written response indicating the measures taken by PG&E to address the probable violations, concerns and recommendations within 30 days from the date of this letter. SED will notify PG&E of the enforcement actions it plans to take in regard to each of the violations found during the audit, pursuant to Commission Resolution ALJ-274, after it has had an opportunity to review PG&E's response to the findings included in the Summary.

For any questions related to this matter, please contact Banu Acimis at (916) 928-3826 or by email at banu.acimis@cpuc.ca.gov.

Sincerely,

Michael Robertson, Program Manager
Gas Safety and Reliability Branch
Safety and Enforcement Division

Enclosure: Summary of Audit Findings

cc: Chris McLaren, PHMSA
Redacted

Summary of Audit Findings

Probable Violations

I. Title 49, Code of Federal Regulations (CFR), §192.905 (b)(1) states in part:

"An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria..."

PG&E's TIMP, Risk Management Procedure (RMP)-06, Revision 8, Section 6.2, Annual HCA Review Process states that:

"HCA analysis is performed on a system wide basis annually by the Risk Management Engineers. The following data are reviewed annually:

- Parcel data
- The latest available aerial and/or street-based photography
- Structure information
- Pipeline information, including but not limited to routine operation and maintenance activities
- Global Positioning System (GPS) information on the pipeline and surrounding structures
- Information from local and state emergency response agencies, including information from first responder meetings, per TD-4003S/RMP-12
- Locations of outdoor gathering areas
- Information from people who live in the vicinity of the pipeline
- Public information available, e.g., on the Internet
- Personal knowledge
- Site-specific feedback from integrity assessment teams
- California Department of Social Services data listing identified sites"

Title 49, CFR, §192.905(b)(1) requires operators to obtain and consider the information from routine operation and maintenance (O&M) activities along the pipeline to identify newly identified sites.

As described in Section 6.2 of RMP-06, PG&E Risk Management Engineers perform High Consequence Area (HCA) analysis on a system wide basis annually.

In a review of PG&E's process for identification of newly identified HCAs, SED noted that even though PG&E's annual HCA review process defined in Section 6.2 of RMP-06 includes routine O&M activities as one of the data sources reviewed annually, SED did not identify any procedure that PG&E utilizes in order to incorporate data from O&M activities into its TIMP.

Pipeline and Hazardous Materials Safety Administration (PHMSA), frequently asked question (FAQ) 18 of Gas Integrity Management states in part that "An operator is expected to make a reasonable effort to identify sites meeting the criteria for 'identified sites'. The rule requires that operators consider information they glean from routine operations and maintenance activities along the pipeline..."

As a result of the 2010 PG&E TIMP audit, SED documented that PG&E had no process for assuring that the HCA information received from sources outside its Integrity Management (IM) group that PG&E properly tracked, documented and integrated HCA information into its Baseline Assessment Plan (BAP) in a timely fashion.

In its 2010 audit response to the Commission, PG&E listed sources of information gathered from public officials and external sources and mentioned a notification from the Vice President of Engineering informing all gas employees to notify the IM group of potential identified sites. However, during the audit, SED found that PG&E did not have any formal process to gather pipeline information from its other departments related to design, construction, operation and maintenance activities which can help gather data to identify new "identified sites".

Therefore, PG&E must do the following:

1. PG&E must establish procedures that document how it incorporates O&M activities in the identification of new HCAs. PG&E must utilize O&M activities such as routine patrols, leak surveys, etc., in addition to satellite imagery and official records to observe changes and evaluate the potential impact on its TIMP and to identify new HCAs.

2. When PG&E identifies new HCAs, it must maintain records that document the date when it identifies a segment of pipeline as an HCA and the method of identification such as routine O&M activities.

II. Title 49, CFR, §192.905 (c) Newly identified areas states in part:

"When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, <u>it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified</u>." [Emphasis Added]

Title 49, CFR, §192.921 How is the baseline assessment to be conducted?

f) Newly identified areas. When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) Newly installed pipe. An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment."

In accordance with Title 49, CFR, §§ 192.905(c), 192.921(f), and 192.921(g), operators are required to do the following:

1. Continual process of performing information analysis includes steps to promptly identify new HCAs including newly constructed segments and new identified sites that are determined to be covered by this rule

2. Incorporate the new HCA affecting segments into the BAP within one year of identification.

3. Complete the baseline assessment of a newly- installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed.

PG&E conducts annual and five-year reviews of its transmission pipelines to identify new HCAs. SED reviewed the Contra Costa County 2011 annual county report and audit change logs as well as the most recent five-year complete review of transmission lines to re-verify HCAs in Contra Costa County. SED noted that PG&E uses "date entered" information shown on its BAP as the HCA identification date; however, PG&E's procedures do not define this data type as the date it identifies a new HCA.

SED also noted that PG&E did not identify some identified sites in a timely manner, which resulted in a delay in the integration of the relevant data into its BAP within a year as required by Title 49, CFR, §192.905 (c).

SED reviewed records and identified newly identified sites which PG&E did not incorporate into its BAP within a year.

Below are two examples of identified sites which PG&E added to its BAP on November 24, 2011.

1. HCA DREG4281, Alameda BJ's Restaurant appeared in the September 28, 2008 imagery

2. Kern Route 142S, Carl's Jr. Restaurant also appeared in the September 28, 2008 imagery

SED also found some newly identified HCAs from new transmission pipeline installations that PG&E did not integrate into its BAP within one year from the date it identified the areas.

For example, PG&E installed transmission line L-191, Segments 133-144 in May 2009 which became operational in November 2009. According to PG&E representatives, the IM group became aware of the newly installed pipeline when it was entered into PG&E's Geographic Information System (GIS) on November 24, 2011. Even though the HCA existed since the start of operation of L-191, Segments 133-144, in November 2009, PG&E did not incorporate this information until November of 2011.

SED determined that PG&E's IM group relies entirely on the information entered into GIS which may potentially delay not only the identification of new HCAs but also the integration of the new HCAs into PG&E's BAP in a timely manner.

SED concluded that PG&E's IM group does not have a documented process of gathering data on the new pipe installations from PG&E's other transmission pipeline groups such as design and engineering.

If PG&E uses GIS as its communication tool between its various pipeline divisions for new construction or physical changes observed in the field, then it must require its divisions to provide timely notification of changes to the GIS group and must establish specific timeframes for such notification.

To summarize, SED reviewed several newly identified HCAs and noted that PG&E's process of updating its BAP to reflect the impact of newly-identified HCAs has the following deficiencies:

1. Annual and Five-year HCA Review: SED noted that PG&E used the "date entered" date as the identification of a new HCA; however, PG&E does not define this data field in its procedures.

2. Audit Change Logs: SED reviewed 2011 audit change logs for Contra Costa County and noted several examples of identified sites which PG&E identified in 2011 that existed a couple of years prior to its identification of the HCAs. PG&E should have discovered these identified sites and integrated them into its BAP prior to 2011.

3. New Transmission Pipelines: SED also found that PG&E did not enter into its BAP some new transmission pipeline information within a year. SED concluded that PG&E is relying on GIS data to gather relevant data to update its program and does not have effective communication with its design, construction, operation, maintenance, and testing departments.

Therefore, PG&E must do the following:

1. PG&E must clearly define in its procedures the date it establishes as the "HCA identification date" to ensure that newly identified covered segments are included in its BAP within a year.

2. PG&E must improve its process of compiling and managing data from different sources and update its HCA list in a timely manner (i.e., BJs and Carl's Junior Restaurants). To do this, PG&E must establish an effective process to communicate with its transmission pipeline design, construction, operations, maintenance, and testing departments to obtain the knowledge about new identified sites in order to identify new HCA segments and to update its BAP within one year of identification.

3. PG&E must obtain the information on its newly installed pipe from the design and construction groups and integrate the information into its TIMP in a timely manner in order to identify and analyze changes to its transmission system and incorporate new HCAs into its BAP within one year of identification.

III- Title 49, CFR, §192.911 What are the elements of an integrity management program states in part:

"An operator's initial integrity management program begins with a framework (see § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements...

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11..."

American Society of Mechanical Engineers (ASME) B31.8S, Section 11, Management of Change Plan states in part "(a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural, and organizational changes to the system, whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:

(1) reason for change
(2) authority for approving changes
(3) analysis of implications

(4) acquisition of required work permits
(5) documentation
(6) communication of change to affected parties
(7) time limitations
(8) qualification of staff"

1. The PG&E IM group becomes aware of new pipe installations after the information is entered into GIS as illustrated in RMP-06, Figure B-9: Management of Change - Physical. If PG&E uses GIS as the main data source for the IM group, then PG&E needs to emphasize the importance of keeping the GIS information current (i.e. requiring new information to be entered within a specific timeframe). PG&E must have a procedure that ensures timely communication to the IM group for newly installed pipeline to minimize delays in identifying HCAs.

   PG&E should also seek to find effective ways to utilize information from its O&M activities that could affect the identification of HCAs such as the construction of apparent identified sites in proximity to a transmission pipeline, verification of possible identified sites unclear in aerial photography using field personnel, and corrections to erroneous pipeline center data submitted by local mark and locate personnel.

   PG&E must verify the knowledge of local field personnel about IM and HCAs and if necessary train local division and district personnel to recognize any changes or corrections that PG&E needs to communicate to the IM group.

   Therefore, as required by Title 49, CFR § 192.911(k), PG&E must develop formal management of change procedures to integrate new information from its routine O&M activities in order to identify newly identified HCAs. Additionally, PG&E's construction department must provide new pipeline installation information to the IM group in order to identify newly constructed pipelines that may be in HCAs.

2. In addition, ASME B31.8S, Section 11, Management of Change Plan states in part "(g) System changes, particularly in equipment, may require qualification of personnel for the correct operation of the new equipment. In addition, refresher training should be provided to ensure that facility personnel understand and adhere to the facility's current operating procedures."

   SED noted that PG&E's Management of Change (MOC) procedure does not reference a requirement to determine if an equipment change would necessitate additional training and qualification of its personnel to ensure the correct operation of new equipment.

   Therefore, as required by Title 49 CFR § 192.911(k), PG&E must have a procedure on how equipment changes are evaluated and implemented. PG&E must add a requirement to its MOC procedure to provide necessary additional training to qualify its employees to correctly operate the new equipment prior to the equipment becoming operational.

IV- Title 49, CFR, §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

"(a) Definition. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference see §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 3, the plan's procedures for preassessment must include –

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502-2008, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) Indirect examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 4, the plan's procedures for indirect examination of the ECDA regions must include –

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment..."

1. Title 49, CFR, §192.925(b)(1)(ii) states in part "...the plan's procedures for preassessment must include...The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA region.".

   PG&E provides in Table 5-3 of RMP-09 the ECDA tool selection matrix consisting of five inspection tools, close interval survey (CIS), direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), electromagnetic pipeline current mapper (PCM), and ultrasonic testing (UT) Guided Wave and 16 different piping conditions and the environment surrounding the pipeline. In Table 5-4 of RMP-09 PG&E provides guidance on indirect inspection and complementary tool selection. The indirect inspection tools (IITs) are selected based on the data collected in the preassessment step of the ECDA process. PG&E records both primary and complementary IITs on its Form D. However, SED noted that PG&E does not document the basis for selecting such tools on Form D or in any other of its records.

   In Section 5.7.3 of RMP-09, PG&E only requires documenting selected IITs but not the basis for choosing such tools. SED did not find any PG&E procedures or records documenting the basis for the tools selected for the ECDA process.

   Therefore, PG&E must establish procedures for documenting the basis for selecting IITs and keep records accordingly in order to justify the effectiveness of the selected tools for the region that PG&E will utilize the IITs in.

   SED also noted that Table 5-1 of RMP-09, Preassessment Data List shows that the depth of cover information is not required information for selecting the IITs for the ECDA process. PG&E explained that it gathers pipeline depth information as a part of its indirect inspection phase.

SED determined that PG&E must have the depth of cover data prior to selecting the appropriate IITs during the preassessment step since the depth of cover may restrict the use of some indirect inspection techniques and IITs.

2. SED noted that PG&E must provide additional specificity to its procedural documentation describing how an ECDA that finds indications of third party damage (TPD) will meet regulatory requirements in Title 49, CFR §§ 192.925(b) and 192.917(e)(1).

   SED found that Section 6.6.1 of RMP-09 does not adequately cover the code requirements. Title 49, CFR, §192.917 (e)(1), *Third Party Damage* states in part "...If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures..."

   SED reviewed the L-132 ECDA assessment and noted that PG&E found mechanical damage on the pipeline at one of the excavation sites. SED also reviewed PG&E's Long Term Integrity Management Plan (LTIMP). Additional mitigation items in the LTIMP stated "In order to decrease the likelihood of impact from third party damage activities, it is recommended that PG&E verify the depth of cover at the locations indicated on the TPD tab and determine if remediation is needed (Mit #7)." The LTIMP also indicated that one of the segments of L-132 that was exposed had a considerable history of TPD and that PG&E confirmed and communicated the depth of cover to its Risk Management Team without a commitment to perform any "work" to reduce the risk.

   SED noted that the intent of the LTIMP was to "... Develop a plan to remediate, and monitor the pipeline in the interim..." SED found a disconnect between what was desired for the single preventive measure for TPD and the action PG&E has yet to propose over five years after its Direct Assessment program was completed and 19 months before its next ECDA assessment must be completed.

   SED determined that if PG&E implements a preventive measure in the future, the LTIMP should provide the acquisition of data for the Nseg which PG&E defines as a 'numbered' transmission line with a portion of the pipeline identified for assessment using ECDA and consists of one or more ECDA Regions. LTIMP should also provide information regarding whether the implemented measure is performed effectively or more information should be augmented to achieve the desired results.

   However, PG&E has not taken action. PG&E must complete the depth of cover verification activities in order to implement preventive measures prior to the initiation of the reassessment.

   SED also noted that since PG&E has such long lag times in completing LTIMPs, it is probable that this issue exists on many of the segments assessed using ECDA where TPD is a threat.

3. Title 49, CFR §192.925 (b)(2)(i) states in part "...the plan's procedures for indirect examination of the ECDA regions must include –

   (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;"

   PG&E does not consider an ECDA on a covered section of pipe as a "first time ECDA" if an ECDA had been performed on a different covered section of the pipe in the past for some of the routes within the same Nseg.

For example, Nseg 220_2010 had six routes, two of which PG&E reassessed. PG&E performed only two excavations (one direct examination and one effectiveness dig) for the other four routes which covered a total of approximately 1.1 miles of pipeline.

PG&E must establish provisions for applying more restrictive criteria for covered segments when conducting the ECDA indirect examination step for the first time on a segment. If the first time indirect examination of certain covered segments did not have more restrictive criteria applied at the time of that examination, PG&E must apply more restrictive criteria during the reassessment to meet the intent of Title 49, CFR, §192.925 (b)(2)(i).

4. Section 8.2.2 Corrosion Rate of RMP-09, Estimated corrosion rates per soil resistivity states: "Other corrosion rates that are scientifically supported may also be used, as described in the paper 'Commentary on Soil Corrosion and Estimates for Pit Growth Rates', dated 01/05/2009."

   SED noted that PG&E takes an exception to allow a corrosion growth rate of "1 mil/year" based on a Mears Group report, titled "PG&E Commentary on Soil Corrosion and Estimates for Pit Growth Rates", dated 01/05/2009. The report conclusions are based on an effective cathodic protection system in that a well coated pipeline could expect to have almost no corrosion with a corrosion growth rate of "1 mil/year."

   SED noted that since PG&E did not define what PG&E's criteria are for an effective cathodically protected pipeline system, the application of this report to PG&E's pipeline systems is questionable. SED also determined that the use of 1 mil/year corrosion rate on PG&E's Line 300A South for an ECDA integrity assessment was not appropriate.

   Table B1 of ASME B31.8S lists corrosion growth rates related to soil resistivity:

   - 3 mils/ year for Soil Resistivity, >15 000 ohm–cm and no active corrosion
   - 6 mils/ year for Soil Resistivity, 1 000 -15 000 ohm–cm and/or active corrosion
   - 12 mils/ year for Soil Resistivity, < 1 000 ohm–cm (worst case)

   The National Association of Corrosion Engineers (NACE) SP 0502-2008 D3.2 states in part "When other data are not available, a pitting rate of 0.4 mm/y (16 mpy) is recommended for determining re-inspection intervals..." and D3.3 states "The corrosion rate in Paragraph D3.2 may be reduced by a maximum of 24% provided it can be demonstrated that the CP level of all pipelines or segments being evaluated have had at least 40 mV of polarization (considering IR drop) for a significant fraction of the time since installation."

   For the purposes of ECDA, as required by Title 49, CFR, §192.925 (b), the corrosion growth rates included in NACE SP 0502-2008 are the only ones that may be used in lieu of actual values. PG&E may not choose corrosion rates from one report and apply them to a "process" while disregarding the requirements of the applicable standard.

5. Title 49, CFR §192.925(b)(3) Direct examination states in part "..(3) Direct examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 5, the plan's procedures for direct examination of indications from the indirect examination must include -

   (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment..."

   Section 5.9.1.2 of NACE RP0502-2002 states "When ECDA is applied for the first time, the pipeline operator should not downgrade any indications that were originally placed in the immediate or scheduled priority category to a lower priority category."

Section 5.2 Prioritization of NACE RP0502-2002 states in part:

> "5.2.1 The pipeline operator shall establish criteria for prioritizing the need for direct examination of each indication found during the Indirect Inspection Step.
>
> 5.2.1.1 Prioritization, as used in this standard, is the process of estimating the need for direct examination of each indication based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion."

SED noted that for the first time ECDA, PG&E reclassifies some of the immediate indications found as a result of indirect assessment based on some of its direct examinations. The NACE standard states that all immediate indications should be excavated if found as a result of indirect examination when ECDA is applied for the first time. If it is a first time ECDA, PG&E cannot use a sample of the immediate indications as a basis for reclassifying all the remaining immediate indications without conducting a direct examination of all identified immediate indications.

PG&E must directly examine all immediate indications found as a result of indirect assessment for the first time ECDA unless PG&E has a documented technical justification for not implementing the NACE recommendation.

V- Title 49, CFR, §192.935 What additional preventive and mitigative measures must an operator take?

Title 49, CFR §192.935 (a) states "General requirements An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs."

PG&E established its procedure RMP-17, LTIMP to identify acceptable preventive and mitigative (P&M) measures for pipeline segments. The LTIMP provides details about how to perform a continual evaluation on PG&E's covered segments of pipeline. PG&E may also use the procedure as a basis for selection of P&M measures on selected non-covered segments with similar characteristics and threat susceptibility.

RMP-17 states that "The LTIMP process includes conducting a review following an integrity assessment, identifying P&M measures, and performing continual evaluations. The integrity assessment review integrates data and develops P&M measures based on threats identified for each pipe segment."

Section 6.4 Communication Findings of RMP 17, states "The LTIMP Engineer shall communicate findings from this process to the relevant groups. All re-assessment determinations shall be communicated to the Risk Group and the group performing the assessment. Where P&M measures have been identified, the groups responsible for implementing the measures shall be notified. Where updates and/or changes are needed to GIS, the Mapping Group shall be notified. Additional information regarding communication of findings is provided in Section 9."

Section 9, Documentation and Communication of RMP-17 states "Communications shall be conducted as often as necessary to ensure that appropriate individuals have current information about the pipeline system. Communications shall take place periodically and as often as necessary to communicate significant changes in the pipeline's integrity. Items requiring immediate action or compliance related concerns shall be communicated to the responsible work group by the LTIMP Engineer and appropriately documented."

1. SED reviewed several LTIMP reports and found that PG&E did not generate many of them in a timely manner.

   For example, PG&E did not create the LTIMP for L-109-2003 until 2009. Since PG&E conducted the baseline assessment for this project in 2003, it was due for a reassessment in 2010. In fact, the LTIMP for this project established the reassessment interval to be five years since some segments were operating at greater than 50% SMYS. SED also noted that since PG&E generated the LTIMP for L-109-2003 six years after it performed its assessment, PG&E completed re-assessments of some of the segments of L-109 before it addressed all of the mitigative and preventive measures that it identified in the LTIMP.

   Additionally, PG&E identified in the LTIMP one high priority P&M measure affecting four stations. One of the stations had a monitoring point installed, but there were no records available for review during the audit indicating how PG&E addressed the other stations. The other two lower priority P&M measures which involved inadequate cathodic protection (CP) levels had no records indicating that PG&E engaged in corrective action to address the non-compliance. PG&E representatives indicated that these would be included in the next self-report notification update.

   SED noted that since PG&E did not create the LTIMP reports in a timely manner after it completed the assessments, PG&E might have not addressed and promptly communicated to the responsible work groups some P&M measures for implementation.

   Section 9.2 of RMP-17 requires that if PG&E cannot complete the work within the given time frame, the Project Lead shall provide justification for the extension and ensure the integrity of the pipeline will not be compromised.

   PG&E created the LTIMP for L-109-2003 six years after the assessment was completed. During the audit, SED also discovered that the work was not competed. SED did not find any documentation for why PG&E generated the LTIMP for L-109-2003 six years after the assessment and why it did not complete the LTIMP work.

   PG&E should have created the LTIMP for L-109-2003 soon after it completed its baseline assessment to identify any additional P&M measures. PG&E should also have implemented necessary P&M measures for the segments or justified the delay in the process of implementing remedial actions.

   During the audit, PG&E provided a copy of its LTIMP summary report which shows all pending LTIMP reports along with P&M work activity measures identified as a result of integrity management assessments.

   As can be seen from Table 1, as of September 2012, PG&E had a total of approximately 610 pending LTIMP projects. PG&E categorized approximately one third of these (229) as Priority 1 projects. This summary report also indicated that PG&E generated more than one third of all its pending LTIMP projects (258) for the assessments conducted prior to 2006 and based approximately 50% (116) of the pending Priority 1 projects on the inspections it conducted prior to 2006.

Table 1- PG&E's Pending LTIMP Projects

Year	Priority 1	Priority 2	Priority 3	Total
2002	1	-	9	10
2003	7	-	10	17
2004	33	-	41	74
2005	75	68	14	157
2006-2007	109	38	189	336
2008	3	-	12	15
2011	1	-	-	1
Total	**229**	106	275	**610**

SED noted that as of September 2012, PG&E has only completed 17% of LTIMPs based on its 2004 baseline assessment mileage. It appears that since PG&E generated LTIMPs several years after the completion of integrity assessments, by the time PG&E started implementing the P&M measures, in some cases, covered segments were due for a reassessment.

SED determined that PG&E RMP-17 neither specifies any timeframe to create an LTIMP after PG&E completes an assessment nor does it require an allowed time interval to complete the implementation of P&M measures.

Therefore, PG&E must establish provisions in its RMP-17 for not only creating LTIMP reports but also implementing P&M measures with specific timeframes after conducting integrity assessments.

2. SED also determined that PG&E does not have an effective method of providing the Risk Management group with the results of the LTIMPs. For example, if an LTIMP discovery indicates a shallow depth pipe, it may increase the likelihood of a TPD risk score for the particular covered segment. Therefore, PG&E must provide the knowledge learned from LTIMP analysis to the other IM groups not only to revise the associated risk factors but also recalculate the reassessment interval of covered segment accurately if necessary.

   On July 24, 2012, PG&E submitted a self-identified non-compliance issue to the Commission involving a missed seven-year integrity reassessment for covered segments on a transmission pipeline in Yolo County which was a violation of Title 49, CFR, § 192.939 (a). PG&E scheduled an integrity reassessment of approximately 5.22 miles of four covered segments on Line 172A by May 24, 2012; however, PG&E failed to conduct the reassessments by the due date. PG&E's analysis determined that it would complete the reassessment work for the four covered segments by August 31, 2012.

   PG&E must clear its LTIMP backlog and establish procedures for implementing its LTIMP process in a timely manner.

   SED has concluded that PG&E must do the following:

- PG&E must initiate the LTIMP process immediately after it completes the assessments to ensure timely implementation of P&M measures.
- PG&E must prioritize the P&M measures and schedule the highest priority ones for implementation promptly for each assessed segment and record them in the database.
- PG&E's IM group must improve its communication with PG&E's other departments in order to take remedial actions in a timely manner.
- PG&E must improve its LTIMP database to track the progress of projects and completed work and to update the status of each project.
- PG&E's LTIMP team must provide documentation for project time extensions in order to justify the need for the extension and to ensure that it would not affect the integrity of the pipeline adversely.

VI- Title 49, CFR, §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Title 49, CFR, §192.937(a) states "After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment."

Title 49, CFR, §192.937(b) Evaluation states "An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats."

PG&E's procedure, RMP-17, LTIMP, Section 7-Continual Evaluation, 7.1-Continual Evaluation Frequency requires "Continual integrity assessment and evaluation as a part of its IMP. Periodic evaluations shall be conducted on an annual basis, within a period not to exceed 15 months. The evaluations shall review leak history, incident notifications, and event reporting information.

Evaluations shall also be conducted in response to the events identified below:

- A failure occurs on the pipeline
- Significant third party damage
- An event such as an earthquake or landslide that may impact the pipeline
- Knowledge or opinion of SME

A periodic evaluation may also be prompted based on the occurrence of additional events, as determined necessary by the LTIMP Engineer."

SED did not find any documentation to verify that PG&E has performed continual evaluation for establishing reassessment methods and schedules by considering all information relevant and required to determining risk associated with pipeline operations in HCAs as required by CFR, §192.937(b). SED noted, at the time of the audit that PG&E recently developed a Continual Evaluation Form; however, PG&E had not implemented the form for usage.

PG&E must consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity assessments. Additionally, SED determined that PG&E does not base prioritization of P&M measures identified in its LTIMP on risk factors, but on upcoming reassessment intervals.

PG&E must prioritize and implement P&M measures identified in the LTIMPs based on their risk score and complete all remedial actions before the next reassessment of the covered segments.

On June 5, 2012, PG&E notified the Commission about self-identified non-compliances involving inadequate CP levels which it did not promptly address on transmission pipelines in its system. During the audit, SED reviewed the list of non-compliances and noted that 87 out of 180 locations in PG&E's current LTIMP reports as pending Priority 1 cases to be mitigated in order to resolve the CP level deficiencies.

SED determined that there is a disconnect between the district CP personnel, corrosion department, LTIMP teams, and ECDA Teams that has resulted in a delay in the implementation of P&M measures for certain CP systems.

PG&E must improve its procedure for continual evaluation in Section 7 of RMP-17, by providing additional specificity to improve the clarity and repeatability of the process. Additionally, PG&E must improve the procedure by adding robustness and missing pieces of information to meet the requirements of CFR, §192.937(b).

During the audit, it was unclear to SED what events and data PG&E needed to complete its "Continual Evaluation Form". PG&E needs to clearly define in its procedures that process for filling-out this form.

PG&E must also expand RMP-17, Section 7.2, Data Integration, since this subject is not adequately addressed in either RMP-17 or the Continual Evaluation Form to meet the requirements of CFR, §192.917(a) and (b).

PG&E must also include a review of Risk Assessment Information in the process to meet the requirements of CFR, §192.917(c).

VII- Title 49, CFR, §192.907 What must an operator do to implement this subpart?

Title 49, CFR § 192.907 (b) Implementation Standards states in part "In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, see §192.7) and its appendices, where specified..."

ASME B31.8S-2004, Section 12 Quality Control Plan states in part:

"This paragraph describes the quality control activities that shall be part of an acceptable integrity management program..."

12.1 General of ASME B31.8S-2004 states:

"Quality control as defined for this Standard is the "documented proof that the operator meets all the requirements of their integrity management program." Pipeline operators that have a quality control program that meets or exceeds the requirements in this paragraph can incorporate the integrity management program activities within their existing plan. For those operators that do not have a quality program, this paragraph outlines the basic requirements of such a program."

12.2 Quality Management Control of ASME B31.8S-2004 states:

"(a) Requirements of a quality control program include documentation, implementation, and maintenance. The following six activities are usually required:

(1) identify the processes that will be included in the quality program

(2) determine the sequence and interaction of these processes

(3) determine the criteria and methods needed to ensure that both the operation and control of these processes are effective

(4) provide the resources and information necessary to support the operation and monitoring of these processes

(5) monitor, measure, and analyze these processes

(6) implement actions necessary to achieve planned results and continued improvement of these processes

(b) Specifically, activities that should be included in the quality control program are as follows:

(1) determine the documentation required and include it in the quality program. These documents shall be controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include risk assessments, the integrity management plan, integrity management reports, and data documents.

(2) the responsibilities and authorities under this program shall be clearly and formally defined.

(3) results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.

(4) 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, shall be part of the quality control plan.

(5) the operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria, and/or performance metrics shall be defined.

(6) periodic internal audits of the integrity management program and its quality plan are recommended. An independent third-party review of the entire program may also be useful.

(7) corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored.

(c) When an operator chooses to use outside resources to conduct any process (for example, pigging) that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program."

1. SED noted that PG&E does not have a Quality Control (QC) Plan which meets all the requirements of ASME B31.8S-2004, Section 12.

PG&E's procedure RMP-06, Section 17, Quality Assurance (QA) outlines its QA plan that verifies the implementation and effectiveness of its TIMP. Section 17.1, Quality Assurance Process states:

"The Company implements systematic activities within a quality process to ensure that the IMP effectively addresses pipeline system integrity issues. Such QA assurance activities include periodic analysis of resulting data to promote continual performance improvement and regular monitoring of the Program's implementation to monitor efficiencies."

The requirements of ASME B31.8S-2004, Section 12 are different than what PG&E describes in Section 17 of RMP-06. The QC activities in RMP-06 aim to identify deficiencies in the actions taken based on a reactive process. On the other hand, QA activities in ASME B31.8S-2004 focus on evaluating integrity management program effectiveness and assessing program efficiency which is a proactive approach.

PG&E must have a QC plan in its TIMP which meets the requirements of ASME B31.8S-2004, Section 12.1 to ensure that the quality control of the actions it performs in assessing the integrity of its pipelines is done properly and that it successfully implements the results of such assessments. The QC plan must also contain all the necessary elements listed under ASME B31.8S-2004, Section 12.2 (a), (b), and (c).

2. According to ASME B31.8S-2004, Section 12.2 (b) (2), operators are required to clearly and formally define the responsibilities and authorities of the personnel who are in charge of the QC program of the TIMP.

In RMP-06, Section 4.0, Roles and Responsibilities, PG&E defines in Table 1 the titles of its personnel who are responsible for performing the tasks within its TIMP. However, PG&E does not provide the titles of the individuals who are responsible for QC and QA Programs.

PG&E must identify its personnel with their specific responsibilities and authorities for implementing the QC and QA plans in order to verify the implementation and effectiveness of its TIMP.

VIII- Title 49, CFR, §192.915 What knowledge and training must personnel have to carry out an integrity management program?

Title 49, CFR § 192.915 states:

"(a) Supervisory personnel. The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for the qualification of any person -

(1) Who conducts an integrity assessment allowed under this subpart; or
(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

c) Persons responsible for preventive and mitigative measures. The integrity management program must provide criteria for the qualification of any person –

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or
(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment."

ASME B31.8S-2004, 12.2 Quality Management Control states in part:

"(b) Specifically, activities that should be included in the quality control program are as follows:

(4) 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, shall be part of the quality control plan."

1. SED reviewed training records of PG&E TIMP program supervisors, project managers, and project engineers and identified some deficiencies. SED found that some employees who are responsible for the assigned Risk Assessment Procedures did not take some Required (R) classes. Table 2 shows the name of the required classes that responsible IM group members failed to complete by their assigned projects. Please provide SED with updated training records of PG&E TIMP team members.

2. As can be seen from Table 2, none of the LTIMP group members took the RMP-17 training class based on the information provided during the audit. PG&E explained that since it issued RMP-17 on 8/17/12, PG&E scheduled its RMP-17 training for 3/31/13.

   SED determined that since PG&E's LTIMP program is identified to be deficient in many aspects and some of the P&M measures proposed in the LTIMPs have not been implemented in a timely manner, PG&E must provide RMP-17 training to its LTIMP supervisor, project manager, and project engineers as well as other team members from other groups who are responsible for managing LTIMP projects as soon as possible. At a minimum, PG&E must provide RMP-17 training for all employees who perform duties such as critical assessment of LTIMP program and evaluation of efficiency and effectiveness of remedial action plans developed for each project.

   SED determined that in order to evaluate the effectiveness of its LTIMP program and individual plans for each project, and prioritize and execute the necessary remedial actions in a timely manner, PG&E must train all of its personnel who are in charge of managing LTIMP projects.

3. SED noted that PG&E's training guidelines lists Risk Management Procedure, RMP-06, Revision 8, Gas Transmission Integrity Management Program training class as "Desired" (D) not "Required" (R). SED determined that since RMP-06 is the controlling procedure for PG&E's Gas TIMP, PG&E must make the RMP-06 training a "Required" class instead of a "Desired" class for all of its TIMP team.

4. PG&E training records show that on 8/23/12, PG&E provided a training session to review the latest approved changes and status updates of RMP-06. However, some of the key personnel did not attend this class. SED also reviewed individual training plan forms and records for those who missed the RMP-06 training and noted that the following TIMP team

members have never taken this class: Chris Wehling, John Nelson, David Slane, and Neb Woldegiorgis.

Table 2- List of required training courses not taken by PG&E IM group

Required Courses	ECDA	ICDA	SCCDA	ILI	LTIMP
Supervisor	Jeff Janvier	Jeff Janvier	Jeff Janvier	Jeff Janvier	Jeff Janvier *RMP-17 training*
Project Manager	Mike West	David He	Mike West	Jeff Janvier	Jeff Janvier
Project Engineer	David He *PG&E Bell Hole Inspection training*	Sean Yost	Dave Aguiar	Chris Wehling *RMP-06 training*	Sonal Patni *RMP-17 training*
Project Engineer				Sukhbir Hundal *PG&E GT&D Corrosion Control training*	Manuel Leija *RMP-17 training*
Project Engineer				John Nelson *RMP-06 training* *PG&E GT&D Corrosion Control training*	Neb Woldegiorgis *RMP-06 training* *RMP-17 training*
Project Engineer				David Slane *RMP-06 training* *PG&E GT&D Corrosion Control training* *Pipeline Defect Assessment Course training*	

ECDA: External Corrosion Direct Assessment
ICDA: Internal Corrosion Direct Assessment
SCCDA: Stress Corrosion Cracking Direct Assessment
ILI: In-line Inspection
LTIMP: Long Term Integrity Management Plan

Concerns and Recommendations

I- Title 49, CFR, §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

1. PG&E's RMP-09, Revision 9, Procedure for External Corrosion Direct Assessment (ECDA) describes the roles and responsibilities of the Field Engineer (FE). During a discussion with PG&E representatives, SED found out that the FE's responsibilities also include designating the segment regions and selecting appropriate indirect inspection tools. PG&E should clearly define the ECDA FE's roles and responsibilities, including these two important job functions in RMP-09, Section 3.0.

2. Title 49, CFR §192.925(b)(1)(i) states in part "…the plan's procedures for preassessment must include… Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment…" SED noted that PG&E's RMP-09 does not have a procedure to describe how it applies and documents the "more restrictive" criteria.

In RMP-09, PG&E listed those activities identified in the PHMSA Gas Integrity Management FAQs as additional alternate activities for the preassessment phase when doing ECDA for the first time. As a requirement, for the preassessment phase, first time ECDA, PG&E personnel must either (1) perform a field visit or (2) collect all available corrosion records per Section 5.3.1 of RMP-09. Section 5.3.1 requires that for first time surveys, PG&E must collect all available corrosion records for the pipeline section.

For instance, PG&E records for a specific casing do not clearly specify starting and ending milepoints; thus PG&E would need to conduct a field visit to verify the location of the casing to accurately establish the region milepoints. In this case, the field visit may not be considered "more restrictive" as the unavailability of records necessitating the field visit. If more data was collected during the field visit, such as collecting data on desired elements, that may be considered as "more restrictive", in which case PG&E will need to clearly document the additional data gathered and describe how the additional data was used for the first time ECDA.

SED noted the same deficiency for the collection of all available corrosion records. SED determined that PG&E must collect all corrosion records as a part of its data gathering phase when it considers using an ECDA. Thus, PG&E must clearly describe what corrosion records it considers to be "extra" or "more restrictive" than those it currently needs to determine the feasibility of ECDA. Additionally, PG&E must document and describe how it uses the additional data for the first time ECDA.

II- Title 49, CFR, §192.933 (b) Discovery of condition states:

"Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1)-(d)(3) of this section. 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, unless the operator demonstrates that the 180-day period is impracticable."

SED found that PG&E's procedure RMP-06, Section 10.2 gives details about "Discovery of Condition" for ECDA, ILI, SCCDA, and ICDA. However, RMP-10 does not describe how PG&E documents the discovery of condition.

SED noted that PG&E's RMP-10, Rev. 2, Dry Gas ICDA, Section 14 (Definitions) defines Discovery of Condition in the same way as it is defined in Title 49, CFR 192.933 (b), which states: "Discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline...." However, PG&E does not describe how it documents the discovery of condition date. PG&E should specify the date when it discovers the condition on its ICDA forms. For example, RMP-09 (ECDA) Section 7.7.3 clearly states that the Examination Date on Form H is the Discover of Condition date.

III- Title 49, CFR, §192.933 (c) Schedule for evaluation and remediation states in part:

"An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation..."

SED noted that Section 9.4.2 of PG&E's procedure RMP-10, ICDA, references "Immediate Repair Conditions" but does not have any reference about how PG&E determines prioritization or the process by which it develops the schedule.

PG&E should add a provision in RMP-10 for documenting how it determines the schedule by prioritizing of conditions for evaluation and remediation.

IV- Title 49, CFR, §192.933 (d) Special requirements for scheduling remediation, (1) Immediate repair conditions states in part:

"An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions..."

In response to the Commission's 2010 audit, PG&E stated "Even though it is PG&E's practice to consider shutting down a line if a safety condition warrants it, based on the Commission'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."

SED noted that even though PG&E included the shut-down option to Section 7.3.1.3 of RMP-11, it still does not specify the conditions that may require shutting-down the pipeline instead of lowering the pressure. Additionally, Appendix A - Direct Examination Process Flow Chart does not show the option to shut down the line.

PG&E should explicitly describe the conditions which require shutting down the pipeline in its RMP-11 and add the same notation to the flow chart in Appendix A.

V- Title 49, CFR, §192.933 (d) Special requirements for scheduling remediation, (3) Monitored conditions states in part:

"Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation: .."

SED noted that there are no provisions in PG&E's procedures RMP-09 ECDA and RMP-13 SCCDA to record and monitor anomalies that are classified as "monitored conditions" during subsequent risk and integrity assessments for any change in their condition that would require remediation. RMP-06, Section 10.3.4 Monitored Conditions has a general statement on recording and monitoring of anomalies; however, there are no references in RMP-09 or RMP-13 related to recording or monitoring these conditions.

PG&E should add a requirement to its RMP-09 and RMP-13 to review anomalies that it does not directly examine to determine the appropriate re-assessment intervals and long-term mitigation plans.