Pacific Gas and Electric Company®

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November 19, 2014

Mr. Ken Bruno
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: State of California – Public Utilities Commission
General Order 112-E Audit – PG&E's Operations and Maintenance Plans

Dear Mr. Bruno:

The Safety and Enforcement Division (SED) of the CPUC conducted a General Order 112-E audit of PG&E's Operations and Maintenance Plans from February 24 through 28, 2014. On October 20, 2014, the SED submitted their audit report, identifying violations and findings. Attached is PG&E's response to the CPUC audit report.

Please contact Larry Berg at (925) 328-5758 or LMB5@pge.com for any questions you may have regarding this response.

Sincerely,

/S/
Bill Gibson

Attachments

cc: Aimee Cauguiran , CPUC
Terence Eng, CPUC
Dennis Lee, CPUC
Liza Malashenko, CPUC
Larry Berg, PG&E
Larry Deniston, PG&E
Sumeet Singh, PG&E

2014 Operations and Maintenance Audit Attachment
PGandE Responses

CPUC Letter Finding #	CPUC Finding	PG&E Response	Associated Attachment (*File Name*)	Future Corrective Action Date
	A. Probable Violations			
NOV-1.1	1. <u>Title 49 CFR §192.13(c) states:</u> *"Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part."* 1.1 <u>Title 49 CFR §191.7(d) states:</u> "If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received." PG&E procedure TD-4413P-01, p.6, states: "b. If the incident is DOT reportable, then within 30 days of the incident, fill out the appropriate DOT Form (either PHMSA F-7100.1, "Incident Report – Gas Distribution," PHMSA F- 7100.2, "Incident Report – Gas Transmission and Gathering Systems" or PHMSA F- 7100.3, "Incident Report – Liquefied Natural Gas (LNG)") on the DOT Office of Pipeline Safety website. (Note: If necessary, such forms may be filled out off-line and emailed or faxed to the DOT. (emphasis added)) Email a copy to the CPUC at Michael.robertson@cpuc.ca.gov and USRB@cpuc.ca.gov along with the letter and form described in Section 6 below." PG&E's procedure TD-4413P-01 does not adequately address the requirements of §191.7(d) because it does not include the requirement to obtain approval from PHMSA before an alternate reporting method (e.g. email, fax) can be used, or to contact PHMSA to make arrangements for submitting a report.	PG&E agrees with this finding. Language pertaining to alternate reporting methods will be removed from Utility Procedure TD-4413P-01 "Reportable Gas Events". The procedure will be revised to report via the DOT Office of Pipeline Safety website in all cases without the option of reporting via alternate methods. Revision to Utility Procedure TD-4413P-01 is targeted for publication by January 31, 2015.	None	31-Jan-15
NOV-1.2	1.2 <u>Title 49 CFR §192.14(a)(4) states:</u> "The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part." PG&E could not provide SED its procedure to address the requirements of §192.14(a)(4) which requires testing of pipelines converted to service.	PG&E agrees with this finding. Utility Procedure TD-9500P-20: "Transfer of Ownership of 3rd Third-Party Installed and Operated Natural Gas Facilities to PG&E" was revised in April 2014 to reference pipe testing requirements within Gas Design Standard A-34, "Piping Design and Testing Requirements." A-34 references Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and other Gas by Pipeline: Minimum Federal Safety Standards49 CFR 192 for Strength Test Requirements.	Utility Procedure TD-9500P-20 (*TD-9500P-20 April 2014_CONF.pdf)*	

NOV-1.3	1.3 <u>Title 49 CFR §192.383(b) states:</u> “(b) Installation required. An excess flow valve (EFV) installation must comply with the performance standards in §192.381. The operator must install an EFV on any new or replaced service line serving a single-family residence after February 12, 2010, unless one or more of the following conditions is present: (1) The service line does not operate at a pressure of 10 psig or greater throughout the year; (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence; (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or (4) An EFV meeting performance standards in §192.381 is not commercially available to the operator.” PG&E’s standard A-93.3, p.2, states: “4. EFVs are not required on services that are replaced in an emergency or on a short lead-time basis. Service replacements to repair Grade 1 leaks are included in this category. Service replacements to repair Grade 2+ and Grade 2 leaks that are not part of an engineered main replacement job are included in this category…” PG&E’s standard A-93.3 does not adequately address the requirements of §192.383(b); Emergency replacements and replacements due to leaks are not exempt from the requirement of installing an EFV.	PG&E respectfully disagrees that this finding is a violation of CFR §192.383(b). PG&E issued Gas Information (GIB) 323 (attached) on February 12, 2010 to address the change in CFR §192.383(b), which required the installation of an EFV on any new or replaced service line serving a single-family residence. GIB 323 amends the language in Gas Standard A-93.3 and requires the installation of an Excess Flow Valve on any new or replaced service line serving a single-family residence after February 12, 2010. GIB 323 further describes the installation of Excess Flow Valves during after hours operation to repair service lines. PG&E will incorporate the language in GIB 323 into the next revision of Gas Standard A-93.3, scheduled for publication by July 31, 2015.	Gas Information Bulletin 323 (*GIB 323_CONF.pdf)*	31-Jul-15
NOV-1.4	1.4 <u>Title 49 CFR §192.455 states:</u> “(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion… …(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that— …(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.” PG&E could not provide SED its procedure to address the cathodic protection requirements for temporary installation under §192.455(c)(2).	PG&E agrees with this finding. It is not PG&E's practice to install buried or submerged temporary facilities and PG&E's procedures mandate that all buried facilities receive cathodic protection within one year of installation (see attached Utility Standard TD-4181S *"External Corrosion Control of Gas Facilities"*). However, to make it more clear within PG&E's guidance documents as to how PG&E complies with cathodic protection requirements for temporary installation of buried gas facilities, PG&E will revise Utility Standard TD-4181S in 2015.	Utility Standard TD-4181S (*TD-4181S_CONF.pdf)*	31-Dec-15
NOV-1.5	1.5 <u>Title 49 CFR §192.465(c) states:</u> “Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.” PG&E could not provide SED its procedure to address the requirements for monitoring reverse current switches, diodes, and interference bonds under §192.465(c).	PG&E agrees with this finding. During its review of the existing corrosion control guidance documents, PG&E identified that this seldom used equipment is not specifically called out for performance checks and documentation. A new work procedure is being developed that identifies and monitors reverse current switches, diodes, and interference bonds as required by §192.465(c). The expected publication date of this new procedure is December 31, 2015.	None	31-Dec-15
NOV-1.6	1.6 <u>Title 49 CFR §192.465(e) states:</u> “After the initial evaluation required by §§ 192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.” PG&E could not provide SED its procedure to address the requirements of §192.465(e) for evaluating unprotected pipelines.	PG&E agrees with this finding. During its review of the existing corrosion control guidance documents, PG&E determined that it did not adequately address the 3-year re-evaluation criteria for cathodically unprotected pipe. A new work procedure is being developed which will address the unprotected pipe evaluation requirements of §192.465(e). The expected publication date of this new procedure is December 31, 2015.	None	31-Dec-15

NOV-1.7	1.7 <u>Title 49 CFR §192.467(f) states:</u> “Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.” PG&E’s procedure TD-4182P-01, intended to address the requirements of §192.467(f), does not address the requirements of protective measures to address the risk associated with fault currents and lightning.	PG&E respectfully disagrees this finding is a violation of CFR §192.467(f). Section 2 (Protective Measures) of PG&E's Utility Procedure TD-4182P-01 covers the types of mitigative actions PG&E takes to address and lower the risk associated with fault currents and lightening. Preliminary analysis has shown that approximately half of the potential arc risk locations identified by section 1) of the procedure were constructed prior to the 1971 regulations. Since that time PG&E has established design standards which require a 25-foot separation or a calculated fault-arcing separation distance on all new construction where applicable and, as previously mentioned, Section 2) of the procedure describes mitigating strategies to eliminate the threat in locations where that might be a concern. This procedure is not intended to cover specific mitigation designs for every possible scenario. Rather, the procedure is intended to cover the general methodology and process by which each possible location throughout the gas transmission system is considered, evaluated, and if necessary, mitigated for possible alternating current interference fault risk. PG&E submitted an ALJ-274 non-compliance notification to SED on December 19, 2012 concerning the failure to protect against potential fault currents, and provided an update on February 11, 2014 (attached). Item 4 on Attachment 2 of this report provides the following progress to identify and mitigate against potential fault currents in close proximity to electric transmission towers and poles throughout the PG&E gas system: "In accordance with the Tier 1 evaluation described in TD-4182P-01, a system-wide review has identified approximately 7,000 locations where there is the possibility of insufficient protection from the threat of AC coupling from a nearby electric transmission lines. From this data, PG&E has begun Tier 2 evaluations, conducting over 550 field assessments. These field assessments have thus far determined that 81% of evaluated locations were in compliance with the required protection criteria, and 19% percent require additional mitigation to provide proper protection based on industry-accepted criteria. The locations requiring further mitigation are being risk-ranked and will be remediated in a timely manner. The remaining approximately 6,450 locations will be field assessed and mitigated as required through a risk-based approach over a 10 year period."	2-11-2014 Self-Report Update-Corrosion issues (*2-11-14 Self-Report Update-Corrosion.pdf*)	Not Applicable
NOV-1.8	1.8 <u>Title 49 CFR §192.469 states:</u> “Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.” PG&E’s standard O-16, p.4, states: “For new transmission pipeline construction, install an ETS station every 2,500’ (Type A installation as shown in Numbered Document O-10)…” PG&E’s standard O-10, p.1, states: “Install test leads on new facilities as follows (refer to Figure 2):Type A: Transmission: At 1-mile intervals, to provide electrical access.” PG&E’s standards do not adequately address the requirements of §192.469 because the standards appear to be in disagreement. O-16 requires an ETS station every 2500 feet while O-10 requires one every 1 mile (5280 feet).	PG&E agrees with this finding. The newly published procedure for cathodic protection design (TD-4181P-101 Rev 0, Section 9.4, published 4/9/2014) is consistent with O-10 Rev 7. In addition, new external corrosion standard TD-4181S, Revision 0, now clarifies that ETSs and CTSs are to alternate approximately every 1/2 mile for new transmission pipe. (section 5.3.2 page 6). Therefore, all PG&E guidance documents consistently state that ETSs are to be installed on new transmission pipe at approximately 1 mile intervals.	Utility Standard TD-4181S (*TD-4181S_CONF.pdf),* Utility Procedure TD-4181P-101 (*TD-4181P-101 Att 1_CONF.pdf*)	Not Applicable
NOV-1.9	1.9 <u>Title 49 CFR §192.481(b) states:</u> “During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.” PG&E’s procedures O-16, TD-4412P-07, and Gas Pipeline Patrol Operations Manual do not adequately address the requirements of §192.481(b) because the procedures do not indicate the requirement or the method on how to give particular attention under thermal insulation, in splash zones, and at deck penetrations.	PG&E agrees with this finding and is in the process of developing new procedures for atmospheric corrosion inspections which specifically address the requirements set forth in 49 CFR §192.481(b). The expected publication date of these new procedures is December 31, 2015.	None	31-Dec-15

2014 Operations and Maintenance Audit Attachment
PGandE Responses

NOV-1.10	1.10 Title 49 CFR §192.503 states: “(b) The test medium must be liquid, air, natural gas, or inert gas that is- (1) Compatible with the material of which the pipeline is constructed; (2) Relatively free of sedimentary materials; and, (3) Except for natural gas, nonflammable.” Table A-1 of PG&E’s standard A-34 states that "Gas" may be used as a test medium for strength testing. On Page 2 of A-34, “Gas” is defined as natural gas, flammable gas, or gas which is toxic or corrosive. However, PG&E must clarify that flammable gases other than natural gas cannot be used as a test medium. In addition, PG&E should consider prohibiting the use of corrosive gas and toxic gas as test mediums; the former may not be compatible with steel pipe and appurtenances, while the latter may pose a public safety threat.	PG&E agrees with this finding that the definition of "Gas" in its Gas Standard A-34 needs to be revised to exclude corrosive, toxic, or flammable gas other than natural gas as a test medium. The next revision to Gas Standard A-34 will include the definition of "Gas" to include only gas allowed for a test medium as defined in 49 CFR §192.503.	None	31-Dec-15
NOV-2.0	2.0 Title 49 CFR §192.603(b) states: “Each operator shall keep records necessary to administer the procedures established under §192.605.” PG&E procedure TD-4001P-02_Attachment_1, Table 2 outlines the priority-based actions for updating and publishing a document revision. However, PG&E may implement a procedure months or years after a revision. PG&E must clearly state in its procedures and communicate with its personnel the effective date of the published, revised documents.	PG&E respectfully disagrees that this finding is a violation of CFR §192.603(b). Gas Operations has listed the effective date of its guidance documents in tailboards and guidance document analysis for many years. Guidance document tailboards and analysis are part of the issuance of all guidance documents and are listed on PG&E's Technical Information Library. Currently, PG&E Gas Operations is publishing the effective date on all gas operations guidance documents to address this issue in an even more clear way.	None	Not Applicable
NOV-3.1	3. Title 49 CFR §192.605 states: 3.1 “(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.” 3.1.1 PG&E currently reviews Code of Safe Practices (CSP) Section 14 – Gas Compressor Stations, which contains operations and maintenance procedures, every 5 years. PG&E does not adequately address the requirements of §192.605(a) because it must review and update the section annually at intervals not to exceed 15 months. 3.1.2 PG&E currently reviews CSP Section 15 – Gas Services, which contains operations and maintenance procedures, every 5 years. PG&E does not adequately address the requirements of §192.605(a) because it must review and update the section annually at intervals not to exceed 15 months.	3.1.1 PG&E agrees with this finding. PG&E's Company Code of Safe Practices, Section 14, Gas Compressor Stations, was on a 5-year review cycle at the time of the audit. PG&E has since added Section 14 of the CSP to its Enterprise Compliance Tracking System (ECTS) document review module with a one-year interval. Section 14 was reviewed by the appropriate subject matter expert on May 15, 2014 and no update was needed. 3.1.2 PG&E disagrees with this finding. Section 15, Gas Services, of the Code of Safe Practice is not needed to demonstrate the Company's compliance with CFR §192.605 for the subject matter it covers. Gas Service procedures are covered in much more detail in the procedures that rollup under Utility Standard TD-6100S, Field Services Operating Practices. Those procedures were reviewed thoroughly and a complete update of all the TD-6100X procedures occurred in the summer of 2014. TD-6100S and its procedures are scheduled for an annual review.	None	Not Applicable
NOV-3.2	3.2 Title 49 CFR §192.707 states: “(d) Marker Warning: The following must be written legibly on a background of sharply contrasting color on each line marker: ... (2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times" Page 1 of PG&E’s standards L-10, L-11.1, & L-12 states: “Presently installed pipeline markers and their corresponding decals do not need to be altered to meet the specifications outlined in this document or other referenced documents.” PG&E standards do not adequately address the requirements of §192.707 because the standards do not require for an update of marker decals upon knowledge that they contain incorrect (i.e. outdated) information.	PG&E respectfully disagrees that this finding is a violation of CFR §192.707. Gas Standards L-10, L-11.1, and L-12 all state in Item #2: "The decals on each marker must be legible and, where applicable, reference the correct phone numbers." In addition, Utility Procedure TD-4412P-09, *Gas Pipeline Markers and Indicators",* which is the procedure for the maintenance of pipeline markers and indicators, states in Section 4.2 "If decals are not legible, are missing, or if the phone number is not consistent with L-10 and L-12, then install or replace the warning decals on the markers." The figures in L-10 and L-12 indicate the correct phone numbers. While PG&E believes these statements in the guidance documents require incorrect phone numbers on warning decals to be replaced, and therefore in compliance with CFR §192.707, it will clarify the language in Gas Standards L-10, L-11.1, and L-12.	None	31-Dec-15

NOV-3.3	3.3 Title 49 CFR §192.717 states: "Each permanent field repair of a leak on a transmission line must be made by— (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or (b) Repairing the leak by one of the following methods… (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design." PG&E could not provide SED its procedure to address the requirements of §192.717(b)(4) for the permanent repair of a leak on a submerged transmission pipeline.	PG&E respectfully disagrees that this finding is a violation of CFR §192.717. PG&E's pipeline repair procedure, TD-4100P-05 *Selection of Steel Pipeline Repair Methods,* does applies to making repairs on all steel pipelines, including repairs to submerged pipelines. CFR 192 subpart M describes the *minimum* requirements for maintenance of pipelines, and PG&E's election to allow welded repairs and pipe replacement in addition to mechanical clamping for both on shore buried and submerged pipelines demonstrates more conservatism than required by code. PG&E plans to make this procedure clearer in a future revision.	None	31-Dec-15
NOV-3.4	3.4 Title 49 CFR §192.735(b) states: "Above ground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30." PG&E could not provide SED its procedure to address the requirements of §192.735(b) for the protection of above ground oil or gasoline storage tanks.	PG&E respectfully disagrees that this is a violation of CFR §192.735(b). The requirement is stated in the current version of TD-4430P-02, in section 2.5 on page 5 (see attached). PG&E apologizes for not presenting this during the audit.	Utility Procedure TD-4430P-02 (*TD-4430P-02_CONF.pdf*)	Not Applicable
NOV-3.5	3.5 Title 49 CFR §192.751 states: "Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following: (a)When hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided." Page 2 of PG&E's Procedures for Purging Gas Facilities, A-38 states: "…Valved vertical vent stacks should be used to keep the natural gas out of the work area and to blow it in a safe direction." PG&E's procedure A-38 does not adequately address the requirements of §192.751 because the procedure does not address the need to provide fire extinguishers during purging.	PG&E agrees with this finding. PG&E's Gas Standard A-38, *Procedures for Purging Gas Facilities"* will be revised to require fire extinguishers be used during purging.	None	31-Jul-15
NOV-3.6	3.6 Title 49 CFR §192.753 states: 3.6.1 "(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172kPa) gage must be sealed with (1) A mechanical leak clamp; or (2) A material or device which: (i) Does not reduce the flexibility of the joint; (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and, (iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53(a) and (b) and 192.143…" PG&E's standard A-39, p.2 states: "All cast iron caulked bell and spigot joints subjected to 25 psig or more must be sealed by means other than caulking. Suitable methods include mechanical bell joint leak-clamps. Refer to 49CFR 192.753(a) and Gas Standards B-50, B-51, and B-51.1…" PG&E's standards B-50, B-51, and B-51.1 have not been active since 2008. Therefore, PG&E's standards do not adequately address the requirements of §192.753(a) because the standards do not contain appropriate sealing procedures. 3.6.2 "(b) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psi (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking." PG&E's standard A-39, p.2 states: "For cast iron mains operating at a pressure of less than 25 psig, each bell and spigot joint exposed by the Company (or exposed by an outside party with the Company's knowledge) must be sealed by means other than caulking. These methods of sealing include, as appropriate, mechanical bell joint leak clamps (B-51.1), internal seals (B-52.1), Avonseal I (25 psig) (B-57), Avonseal II (1 psig) (B-58), heat shrink sleeves (1 psig) (B-56), or other methods approved by the GD&TS department. Refer to 49CFR 192.753(b)." PG&E's standards B-51.1, B-56, B-57, and B-58 have not been active since 2008. Therefore, PG&E's standards do not adequately address the requirements of §192.753(b) because the standards do not contain appropriate sealing procedures.	PG&E agrees with this finding. All known cast iron gas lines in PG&E's gas system are scheduled for removal or de-activation by December 31, 2014. Upon such completion, Gas Standard A-39 will be removed from publication and saved as a reference document only.	None	30-Mar-15

NOV-4.0	4.0 General Order (GO) 112-E, Section 122.2 states: "(a) Each operator shall report incidents to the CPUC that meet the following criteria… (2) "Incidents which have either attracted public attention or have been given significant news media coverage, that are suspected to involve natural gas, which occur in the vicinity of the operator's facilities; regardless of whether or not the operator's facilities are involved." PG&E procedure TD-4413P-01, section 1.2 states: "1. All events that meet any of the following criteria are considered reportable gas incidents and must be reported to the CPUC…… b. Events that have attracted coverage by major news media ("major news media "are defined as Bay Area, Sacramento, and/or national network TV news stations), and include the release of gas from a Company facility." PG&E's procedure TD-4413P-01 does not adequately address GO 112-E Section 122.2, because it does not indicate that events that have attracted media coverage must be reported if suspected to involve natural gas, which occur in the vicinity of the operator's facilities, regardless of whether or not the operator's facilities are involved (i.e. a release of gas is not necessary).	PG&E agrees with this finding. Utility Procedure TD-4413P-01 "Reportable Gas Events" will be revised to report incidents that have attracted public attention or have been given significant news media coverage to be reported to the CPUC regardless whether or not gas is released. Revision to Utility Procedure TD-4413P-01 is targeted for publication by January 31, 2015.	None	31-Jan-15
	B. Areas of Concern / Recommendations			
AOC-1.0	1. PG&E should consider explicitly defining acronyms VT, MT/PT, and RT listed in Table 2 of PG&E procedure TD-4160P-20.	PG&E agrees with this concern and will consider adding definitions into the welding manual for these inspection acronyms listed in Table 2 of TD-4160P-20 for added clarity.	None	31-Dec-15
AOC-2.0	2. PG&E currently reviews and updates the introduction to TD-4133M Gas Transmission and Distribution Manual Corrosion Control Volume every 5 years. PG&E should consider reviewing and updating the introduction to TD-4133M annually since it outlines staff roles and responsibilities pertaining to operations and maintenance procedures.	PG&E agrees with this concern and will remove this section from the Corrosion Control Manual on the next revision.	None	31-Dec-15
AOC-3.0	3. PG&E standard D-S0353 / S4112, p.2 states, "The exposed portion of any buried metallic piping must be examined for external corrosion, if it is bare or if the coating is deteriorated." PG&E should consider updating its standard to address possible corrective actions taken when exposed portions of buried pipe (e.g. as a result of washouts, erosion) are identified and examined. The procedure should also require documenting the corrective actions.	PG&E agrees with this concern. Addressing exposed portions of buried metallic piping, including required mitigative actions, will be part of planned Corrosion Control guidance documents. Standard D-S0353 / S4112 will be reviewed and scheduled for cancellation when the planned Corrosion Control guidance documents get published in 2015.	None	31-Dec-15
AOC-4.0	4. PG&E procedure TD-4540P-01, p.16 states: "IF sulfur is present on station internal components, THEN perform the following tasks. 1. Write presence of sulfur on back of proper maintenance record. 2. Notify senior gas quality engineer." PG&E should consider updating procedure TD-4540P-01 to include how it plans to physically address the presence of sulfur when discovered on its internal components.	PG&E agrees with this concern. TD-4540P-01 will be clarified by specifically stating that when sulfur is found on on internal components, it must be removed or the components must be replaced. The publication date for the revision to TD-4540P-01 is targeted for July 2015.	None	31-Jul-15
AOC-5.0	5. PG&E procedure TD-4540S, p.3 states: "Class C Inspection (internal inspection) An internal inspection of station components after station construction or reconstruction. Station components in the flowing gas stream are checked internally for presence of weld slag and shavings. Filter elements and rubber goods are replaced only for cause." On page 4 of TD-4540S, Table 2 states that Class C inspections are not required at farm tap regulator sets, large volume customer regulator sets (HPR-type), and district regulator stations (HPR-type). Since all types of regulators could potentially have slugs and shavings after construction or reconstruction, PG&E should consider updating its procedure to include a requirement for performing Class C inspections at the aforementioned sets and stations where feasible.	PG&E has found HPR-type regulators to be extremely durable, and has observed very few failures in these types of regulators caused by weld slag or debris. PG&E has not had a compelling technical basis for requiring Class C inspections of these regulators.	None	Not Applicable
AOC-6.0	6. Page 1 (Notes) of PG&E forms FH-70-A, FH-70-B, and FH-70-C states: "All pressure relief devices shall be inspected, tested, and the capacity reviewed at intervals not exceeding 15 months, but at least once each calendar year. Furthermore, in addition to the annual capacity testing, the capacity of the relief devices shall be verified immediately when changes are made which could affect the ability of the relief device to protect the connected systems." For consistent interpretation throughout the system, PG&E should consider updating its procedures to include a list of examples of the most common changes that require immediate relief valve capacity verification.	PG&E agrees with this concern. Greater clarity will be provided in Gas Standard H-70 by including examples of changes affecting relief capacity. Examples will be included in the next revision to this document, which has a targeted publication date of July 2015.	None	31-Jul-15
AOC-7.0	7. PG&E standard H-70 is applicable for both transmission and distribution systems; however, Table 1 is titled "Distribution Systems". PG&E should consider revising the title of Table 1 to include transmission systems.	PG&E agrees with this concern. Table 1 addresses both Distribution and Transmission systems. The title will be corrected in the next revision to this document, which has a targeted publication date of July 2015.	None	31-Jul-15

AOC-8.0	8. During a discussion regarding the use of cheater bars for valve maintenance, PG&E stated that cheater bars are not allowed to be used. However, PG&E procedure TD-4430P-04 (Appendix E) does not disallow the use of cheater bars; it only lists the acceptable maximum wrench length. SED has witnessed the use of cheater bars during field inspections; therefore, PG&E should consider updating its procedure to explicitly prohibit staff from using cheater bars.	PG&E agrees with this concern. A new wrench tool with built-in extension, or a company-approved wrench extension will be explored for use in the field, as an alternative to cheater bars. The new tool will ensure torque limits are not exceeded. This will be addressed in an upcoming new valve maintenance standard, TD-4520S, expected to be published in the 4th quarter of 2015.	None	30-Nov-15
AOC-9.0	9. PG&E Standard A-39, p.2 states: "10) Whenever a cast iron pipeline is exposed for any reason, it must be inspected for evidence of graphitization. Graphitization occurs when the iron corrodes, leaving only graphite. The pipe appears intact, but is soft and can be easily cut with a knife or other sharp instrument." PG&E should consider updating standard A-39 and related procedures to provide guidance on how to identify graphitization; specifically, adding procedures for staff to objectively identify graphitization.	PG&E agrees with this concern. All known cast iron gas lines are scheduled for removal or de-activation by December 31, 2014. Upon such completion, A-39 will be removed from publication and saved as a reference document only.	None	30-Mar-15
AOC-10.0	10. SED discovered several PG&E procedures containing outdated references. Based on the priority matrix in TD-4001P-02_Attachment_1, it would appear that many low priority procedures may not be updated until much later (even when only simple changes to outdated references are needed). PG&E should consider performing simple changes to outdated references immediately. Several examples are listed below: A. PG&E has not incorporated Bulletin 280, published on 07/13/09, into Vault Inspection Standard S4446. B. PG&E has not incorporated the bulletins for TD-4430P-02 [322 (published 02/2010), 325 (06/2010), TD-4430B-002 (03/2011)] into TD-4430P-02. C. PG&E's standard A-36 makes references to General Order 112-D which has since been supplanted by 112-E, and Engineering Standard 90 which PG&E could not provide to SED during the audit.	PG&E appreciates feedback concerning the updating of its guidance documents and will consider making enhancements to TD-4001P-02. PG&E will look to incorporate bulletins and update outdated references in the noted guidance documents. Engineering Standard 90 has been replaced with Engineering Material Specification 4123 "Backfill Sand". (See attached)	Engineering Material Specification 4123 (*EMS 4123_CONF.pdf*)	31-Dec-15
AOC-11.0	11. PG&E's continuing surveillance procedure TD-4800S identifies all of the various programs that cover operations and maintenance tasks as part of the continuing surveillance program. TD-4800S currently states, "Appropriate company personnel review and analyze facility records periodically". PG&E expressed during the audit that PG&E's Integrity Management (IM) group has oversight on the continuing surveillance program, but procedure TD-4800S does not reflect this information. PG&E should consider updating procedure TD-4800S to clearly define the "appropriate company personnel" who have oversight of the surveillance program and the frequency of its review.	PG&E agrees with this concern and will consider updating Utility Standard TD-4800S, "Continuing Surveillance", to define which personnel have oversight of the continuing surveillance program, and what role the Integrity Management group has in identifying and mitigating risk on the pipeline using data from the continuing surveillance program.	None	31-Dec-15
AOC-12.0	12. PG&E indicated that it has a system-wide program for handling suspected contacted casings. PG&E should update its procedures to include the details and responsibilities of the program.	PG&E agrees with this concern and recently published new procedures for casing testing and mitigation. These procedures clarify roles and responsibilities. This item has been addressed in Utility Procedures TD-4181P-601 *Testing Procedures of Pipe Casings,* and TD-4181P-602 *Mitigating Casing Contacts* , currently on PG&E's Technical Information Library.	Utility Procedure TD-4181P-601 (*TD-4181P-601_CONF.pdf*), Utility Procedure TD-4181P-602 (*TD-4181P-602_CONF.pdf*)	Not Applicable
AOC-13.0	13. Page 14 of PG&E's standard A-34 states, "For fabricated units or short sections that will have an MAOP at or above 30% SMYS, the pre-installation test shall be a minimum of 4 hours." PG&E should consider updating its procedure with a prescribed length defining "short sections" of pipe to ensure consistency throughout its system.	PG&E agrees with this concern and will update the definition of short sections of pipe in the next revision to Gas Standard A-34.	None	31-Dec-15
AOC-14.0	14. PG&E's informational job aids TD-4151M-JA33 and JA46 detail the inspection and leak testing process of drilling machines used for tapping transmission pipelines. This testing is accomplished by using compressed air to pressurize the tapping machine body to ensure the integrity of the drilling machine which might hold transmission line pressures during hot tapping. PG&E should consider updating its procedures to establish a recommended interval for the inspection and leak testing process of drilling machines.	In the equipment operation procedures for these tools, they presently instruct the equipment operator to perform equipment maintenance and inspection before use and in the course of that inspection, if the equipment's operability or condition is doubted, a pressure test shall be completed. So PG&E operators of this equipment are preforming these steps before every use, thereby superseding the need to write in a recommended interval.	None	Not Applicable
AOC-15.0	15. Title 49 CFR §192.735(a) states: "Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building." PG&E procedure TD-4430P-02, p.5 states: "Store supplies of flammable or combustible materials not required for everyday use or other than those normally used in compressor buildings a safe distance from compressor buildings." To ensure consistency throughout its system, PG&E should consider updating its procedure to specify a length of separation to define "safe distance".	PG&E agrees with the concern to provide clarity when describing a safe distance to store flammable or combustible materials from a compressor building, although rather than specifying an absolute distance, PG&E will revise its procedure to include a description of safely storing such materials and potential separation by non-flammable barriers.	None	31-Dec-15

AOC-16.0	16. PG&E standard A-38, section (1)(c) refers to "Section 192.727 of General Order 112". General Order 112 does not contain a Section 192.727. PG&E may be referring to Title 49 CFR Part 192, and should edit standard A-38 accordingly.	PG&E agrees with this concern. PG&E's Gas Standard A-38, *Procedures for Purging Gas Facilities"* will be revised to correct this reference.	None	31-Jul-15
AOC-17.0	17. SED would like to know if PG&E allows for the installation of aluminum pipe as per §192.455(e). If so, please provide a reference to the procedure.	Aluminum pipe is not approved for installation at PG&E and, therefore, there are no procedures addressing it. PG&E will consider including such a statement in the next version of Ga Standard A-36, "Design and Construction Requirements Gas Lines and Related Facilities".	None	Not Applicable
AOC-18.0	18. SED would like to know if PG&E has exemptions under §192.479(c) from protecting aboveground pipe from atmospheric corrosion. If so, please provide a reference to the procedure that describes how PG&E determines if the exemption applies. In addition, to ensure consistency throughout its system, PG&E should consider updating its procedures to include how to address unpainted pipe upon discovery in the field.	PG&E agrees wit this concern. PG&E does not have an exemption from protecting aboveground pipe from atmospheric corrosion. The updated procedures for atmospheric corrosion will provide additional guidance on how to address atmospheric corrosion on exposed pipe.	None	31-Dec-15
AOC-19.0	19. PG&E's procedure TD-4430P-02, p.15 states: "A main gas relief is considered to be operating properly when the following conditions exist: ... • The relief shuts off completely at the prescribed "reseat" pressure." SED would like to know how PG&E verifies reseat or reseal at the prescribed pressure settings, and where the results are documented.	PG&E agrees with this concern. Utility Procedure TD-4430P-02 is being superseded by various asset or process guidance documents. The maintenance of relief valves will follow the guidance in Utility Procedure TD-4540P-01, Maintenance of Regulator Stations. The new guidance documents are expected to be rolled out in 2015.	None	31-Dec-15
AOC-20.0	20. TD-4430P-02 p.7, 4.1.2 states: "2) Pneumatic Piston Actuators: "Stroke the valve and check for smooth operation annually. Record the open-to-closed and closed-to-open travel time." The inspection form for this activity (TD-4430P-02-F03) does not have a space/field to record either the acceptable or actual travel times. PG&E should consider specifying the acceptable travel time for the actuator type listed.	PG&E agrees with this concern. Utility Procedure TD-4430P-02 is being superseded by various asset or process guidance documents. The maintenance of actuators will follow the guidance in the new Utility Procedure TD-4540P-10, Maintenance of Power Actuators, and will address acceptable travel times. The new guidance documents are expected to be rolled out in 2015.	None	31-Dec-15
AOC-21.0	SED would like to know if PG&E has exceptions to odorizing gas as per §192.625(b). If so, please provide a reference to the procedure that describes how PG&E determines if the exemptions apply.	PG&E does not have exceptions to odorizing gas per 192.625(b)	None	Not Applicable
AOC-22.0	22. Title 49 CFR §192.739 states: "(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is— ... (3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a);" PG&E's bulletin, TD-4430B-002 (page 1) states: "Alternate Monitor Testing (MUST USE THIS METHOD) Lower the monitor set point until the monitor takes over control and observe the monitor controllability. After satisfactorily controlling pressure through the monitor valve, return the monitor set point to the original setting. Then check the monitor set point by simulating a pneumatic signal to the controller sensing line. Ensure that the appropriate set points are reestablished." PG&E bulletin TD-4430B-002 requires testing the monitor's functionality at a setting below its normal operating set point. SED would like further explanation on how PG&E can conclude that this test meets the requirements of §192.739(a)(3).	PG&E's practice is in compliance with 192.739, which states (a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is— (1) In good mechanical condition; (2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed; (3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a) PG&E's procedure includes lowering the set point of the monitor and allowing it to control pipeline pressure at that lower set point. Observing the performance of the monitor while controlling pressure allows the technician to evaluate the condition of the device and satisfies 192.739(a)(1) and (2). In order to reestablish the correct set point, a pressure signal is applied to the pilot or controller using an external pressure source. The monitor will begin to react (i.e. the valve will begin to close) when this applied pressure reaches the set point. The set point is adjusted until the desired value is achieved. Although the source of the pressure signal is an external source, it is reasonable to expect that the monitor would respond similarly if the source of the pressure were the pipeline itself. After set point adjustments are complete, the monitor is confirmed to control at its set point by applying the external pressure to the monitor's pilot or controller sensing line. This satisfies 192.739(a)(3) without requiring the pressure within the pipeline itself to be elevated above the MAOP.	None	Not Applicable

AOC-23.0	23. PG&E procedure TD-4125S, p. 4 states: "For distribution systems operating at MAOP of 60 psig or less, if there is no pressure record available to document the operating pressure of a system during the 5 years prior to July 1, 1970, establish the MAOP alternatively by the documented pressure of the system during the most recent leak survey made in the period between July 1, 1970 and March 1, 1979. The leak survey must demonstrate the system to be safe while operating at the documented pressure (meaning the documented pressure at time of survey or before and after survey). If a leak survey was made but there is no record of the pressure at the time of survey (or before and after the survey), establish the MAOP as the pressure of record, if knowledgeable personnel can certify that the pressure at the time of the survey was the same as the pressure of record. The next leak survey must verify MAOPs established in this manner." Please provide information on PG&E's basis for establishing MAOP using documented operating pressure of the system during the most recent leak survey conducted between July 1, 1970 and March 1, 1979. In addition, please provide the number of miles of distribution pipeline in which PG&E has established its MAOP in accordance with the aforementioned section of PG&E procedure TD-4125S.	PG&E has used this basis for establishing distribution systems' MAOP since the late 1970's. During that period, PG&E realized that pressure records during the 5 years prior to July 1, 1970 for some distribution systems could not be found. PG&E's standard practice provided an option to require a pressure record after July 1, 1970 with a subsequent leak survey in order to demonstrate safe operation and establishment of a system's MAOP. PHMSA's instructions on the determination of MAOP in natural gas pipelines (attached and currently available on PHMSA's website: http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/maop_determination.pdf), dated April 22, 1998, describes considerations of missing records in Section C. It is not known whether PG&E consulted the CPUC in the late 1970's in specifying this option to establish distribution MAOPs. PG&E has reviewed distribution system MAOP records and determined that of the 1376 hydraulically independent systems, approximately 240 systems have had their MAOP established using this basis.	PHMSA Instructions on the Determination of MAOP in Natural Gas Pipelines (*PHMSA maop_determination.pdf*)	Not Applicable