Attachment A: PG&E Comments on SED Proposed Revisions to GO 112-E

Proposed Rule Change #	Title	New/Revised Language (Highlighted in [illegible])	Operations Impact/Comments
PRC-3	105 Definitions	Public Attention criterion means any event that escalates to a level that initiates concerns being submitted to a utility from a large number of people. This can include, for example, large scale reports of the smell of gas by customers in the vicinity of an operator's gas facilities. Public Attention criterion does not necessarily include an individual, or a crowd of persons, watching work being performed on company facilities.	Minor to moderate impact to process and procedures. No cost recovery implications. PG&E will need to update its procedure and this will most likely increase the number of reportable incidents due to media presence. PG&E requests a clear definition of what constitutes a "large number of people" to ensure consistent compliance.
PRC-3	105 Definitions	Covered Task means those tasks defined by 49 C.F.R §192.801, but also includes "new construction" in the federal definition of "covered task." Accordingly, the Commission defines a covered task that will be subject to the requirements of 49 CFR §§ 192.803 through 192.809 as an activity, identified by the Operator, that: (a) Is performed on a gas pipeline; (b) Is an operations, maintenance, or new construction task; (c) Is performed as a requirement of 49 CFR, Part 192; and (d) Affects the operation or integrity of the gas pipeline.	PG&E is generally supportive of this change. However, it does represent a significant impact to our Operator Qualification (OQ) program, construction program and the applicant installation process. PG&E has identified 12 new OQ tasks that will need to be proceduralized and communicated to all PG&E field personnel and contractors. PG&E anticipates 3 to 5 years to develop and communicate the new processes, with approximately 3 trainers dedicated to supporting these efforts, at a cost of approximately $1 million. PG&E estimates that the cost for each employee to be fully operator qualified would be approximately $13,000, totalling approximately $3.25 million to implement the program on PG&E facilities. It should be noted that this number is a best-case scenario, and there may be some re-testing or re-training associated, as well. Additionally, the applicant installation advice letter "GENERAL TERMS AND CONDITIONS FOR GAS AND ELECTRIC EXTENSION AND SERVICE CONSTRUCTION BY APPLICANT, Advice 3248-G" will need to be updated and filed with the CPUC. Significant cost recovery impact.

PRC-3	105 Definitions	High Consequence Area (HCA) is defined by 49 C.F.R §192.903, which allows two different methods to be used towards determining locations where HCAs exist. However, in an effort to be more conservative towards ensuring the safety in areas of more densely populated Class 3 and Class 4 locations, the Commission restricts Operators to using Method 1, as defined in 49 C.F.R §192.903, in determining HCAs. Accordingly, the Commission defines a high consequence area as: (a) A Class 3 location under § 192.5; or (b) A Class 4 location under § 192.5; or (c) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or (d) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.	This proposed change would cause a significant impact to PG&E's Transmission Integrity Management Program (TIMP). PG&E currently utilizes Method 2, which is consistent with common industry practices. In 2009, PG&E reported the second highest number of HCA miles for any operator in the United States, representing 9.3 percent of the total number of HCA miles within the nation. A Method 1 HCA calculation based on current transmission mileage would result in an increase of approximately 618 miles to PG&E's TIMP. Method 2 is a technical basis for HCA determination because it considers the actual area where a potential failure of a pipeline could have significant impact on people or property. Method 1 is based upon class location, which is determined with an evaluation of structure counts within 660' of the pipeline regardless of Potential Impact Radius (PIR). Many locations have PIR's that are much smaller than 660' and even though pipe may be designated as class 3 or 4, the pipe will pose no risk to structures or property outside the PIR. An example would be to consider a pipe with a PIR of 200', and where a housing development or a "class 3 structure" is 300' away. This would be class 3 based on buildings within 660', but all of the buildings are located outside the PIR and therefore are not at risk due to their distance from the pipeline. PG&E is committed to expanding integrity management principles outside of HCAs. However, additional requirements for TIMP integrity assessments using Method 1 may shift the prioritization of additional assessments toward lower risk class 3/4 areas where structures may not exist within the PIR, instead of toward higher risk non HCA areas. Significant cost recovery impact.
PRC-3	105 Definitions	Near-miss events mean unplanned events that do not result in injury, illness, damage, release of gas, loss of gas service, or over-pressurization of gas pipeline facilities, or in an otherwise reportable incident, but had the potential to do so. Such events can include, but are not limited to: (a) A subsurface pipeline facility mismarked for excavation purposes; (b) The operation of an incorrect valve or pressure regulator; (c) An incorrectly mapped pipeline facility; (d) Deficiencies identified in an approved standard, procedure or process.	Need to clarify that the events are within the sphere of influence of the operator. Operators have no way of identifying near misses for which they have not been made aware. This will take some time to implement. No signifcant cost recovery impact anticipated.

PRC-4	122 Incident Reports	122.2 (a) New criteria: 2. Incidents which have either attracted public attention or have been given significant news media coverage, that are suspected to involve natural gas and/or propane (LPG) gas, which occur in the vicinity of the operator's facilities; regardless of whether or not the operator's facilities are involved. 3. Incidents where the failure of a pressure relieving and limiting stations, or any other event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable limitations set forth in 49 CFR § 192.201. 4. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other event other than excavation related damage, results in any part of the gas pipeline system losing service or being shut-down.	Minor impact. Already collecting this information, but will need to update reportable incident process to get the information in a timely fashion and report. No significant cost recovery impact anticipated.
PRC-4	122 Incident Reports	122.2 (d) Quarterly Summary Reports. Each operator shall submit to the CPUC quarterly, not later than the end of the month following the quarter, a summary of all CPUC reportable and non□reportable gas leak related incidents which occurred in the preceding quarter as follows: 5. Incidents where the failure of a pressure relieving and limiting stations, or any other event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable limitations set forth in 49 CFR § 192.201. 6. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other event other excavation related damage, result in any part of the gas pipeline system losing service or being shut-down.	Minor impact. Already collecting this information, but will need to update gas quarterly incident process to include the information in the report. No signficant cost recovery impact anticipated.
PRC-5	123 Annual Reports and Mechanical Fitting Reports	123.2 b) For leaks replaced in the calendar year, show time between finding the leak and its repair in intervals of 0-3 months; 6-9 months; 9-12 months; 12-15 months; and greater than 15 months. For the aggregated value of leaks repaired greater than 15 months, segregate the value into leaks that are never regraded; regraded once; regarded twice; regraded three times; and regraded more than three times.	Assume "leaks replaced" should be "leaks repaired". This information can be collected. No signficant cost recovery impact anticipated.
PRC-5	123 Annual Reports and Mechanical Fitting Reports	123.2 c) Response times, segregated in five-minute intervals and by Division, District, and/or Region, to reports of leaks or damages reported to the Operator by its own employees or by the public. The intervals start with 0-5 minutes, all the way to 40-45 minutes, and with all response times greater than 45 minutes. The timing for the response starts when the utility first receives the report and ends when an Operator's qualified representative determines the reported leak is not hazardous or the Operator's representative(s) complete actions to mitigate a hazardous leak and render it non-hazardous. In addition, the Operator must report, using the same intervals, the times for the first company responder to arrive on scene.	PG&E does not currently have the capability to track the response times from when the report is received to the time the reported leak is not hazardous. The response times are tracked from the time the report is received to the time the first responder is on scene. Request a clear definition of what is meant by making a leak non-hazardous. Minor to moderate process impact, no significant cost recovery impact anticipated.
PRC-5	123 Annual Reports and Mechanical Fitting Reports	123.2 h) 3. Number of person-days, along with total costs, devoted to: i) excavation field meetings (per GC4216); and ii) stand-by activities for preventing damage to subsurface facilities during an excavation;	We currently are not able to provide this information, as there is not a mechanism in place to account for time spent on these activities that are performed in the course of a field employee's work day.

PRC-5	123 Annual Reports and Mechanical Fitting Reports	123.2 h) 4. Number of person-days, along with total costs, devoted to: i) mark and locate activities (per GC 4216); and ii) all other subsurface damage prevention activities excluding those from paragraph 3 above.	We currently are not able to provide this information, as there is not a mechanism in place to account for time spent on these activities that are performed in the course of a field employee's work day.
PRC-5	123 Annual Reports and Mechanical Fitting Reports	123.2 i) 1. A listing of the different causes of LAUF Gas that the Operator tracks as part of its operations; and	This information is not currently available. PG&E does not track various LUAF causes. Instead, our LUAF calculation comes from a mass balance of the system: LUAF = Measured inputs – Measured outputs, adjusted for changes in pipeline inventory.
PRC-5	123 Annual Reports and Mechanical Fitting Reports	123.2 i) 2. An accounting of the effects of each of the different causes of LAUF Gas, actual and/or estimated values, which factor into the aggregated LAUF Gas value provided by the Operator on all reports submitted pursuant to subsection 123.1.	This information is not currently available. Information on gas released to atmosphere is available from the Green House Gas reporting provided to the California Air Resources Board.
PRC-9	142 Plastic Pipe	**142.1** Plastic Pipe Storage At the time of installation, plastic pipe to be used for gas transportation, shall not have been subjected to unprotected outdoor exposure longer than the time recommended by the manufacturer, ~~or~~ the time period specified in the operator's operations and maintenance plan, or 2 years, whichever ever is least.	PG&E respectfully disagrees with this proposed change. Current manufacturer recommendations is 3 years which has been validated through testing. PG&E installs PE pipe manufactured in accordance with the latest edition of ASTM D2513, which requires that the pipe be suitable for at least 3 years of outdoor storage. Our approved manufacturers guarantee the pipe they produce can be stored outdoors for 3 years or more and still meet all performance requirements. Performance Pipe has performed and documented testing that demonstrates that 3 years of outdoor storage is acceptable (and is actually a conservative limit).
PRC-10	143 Distribution and Transmission Systems	**143.4 Operator Qualification** - The equipment and facilities used by a gas pipeline company for training and qualification of employees must be similar to the equipment and facilities on which the employee will perform the covered task.	No comment other than to request a definition of "similar". No significant cost recovery impact anticipated.
PRC-12	145 Transmission Lines: Recording	(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. However, repairs, or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.	More clarity on what is meant by "tests" would be helpful. No significant cost recovery impact anticipated.
PRC-12	145 Transmission Lines: Recording	(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.	More clarity on what is meant by "tests" would be helpful. No significant cost recovery impact anticipated.
PRC-14	162 Liquefied Natural Gas Facilities	162.4 All operators must include mobile LNG equipment within the written operations and maintenance plans required by 49 CFR, Part 192, §192.605. Operators must provide written, detailed, procedures for the operation and maintenance of their mobile LNG units. These procedures must include a requirement to perform operational tests of mobile LNG equipment, after any modifications are performed to the equipment (including computer equipment and software) that could affect equipment operation, before using modified equipment for actual field use.	It is PG&E's opinion that 192.605 is not the correct code reference for OM&E procedures for mobile LNG equipment, as Part 192 is written for pipeline facilities. The more appropriate reference would be parts of 49 CFR Part 193 and NFPA 59A. PG&E is currently working with AGA and the NFPA 59A code committee to expand the requirements for mobile LNG facilities to include more sections of the existing 59A code. PG&E has an extensive manual for operations, maintenance and emergency response for its mobile LNG facilities.