State of California
State Energy Resources Conservation and Development Commission

In the Matter of:	)	Docket # 09-AFC-04
	)	Exhibit 408
Oakley Generating Station	)	Pipeline Testimony of
	)	Robert Sarvey
	)	
	)	

Introduction

PG&E's gas system includes about 6,418 miles of transmission pipeline, 50 miles of gas gathering pipeline and more than 42,017 miles of distribution pipeline. The gas transmission facilities are broadly classified as either backbone transmission or local transmission. Line 303 and Line 400 are a part of PG&E's backbone transmission system. PG&E's backbone transmission system consists of the northern facilities (Lines 400, 401 and 2), the southern facilities (Lines 300 and 319), the Bay Area loop (Lines 107, 114, 131 and 303), and eight compressor stations that move gas through PG&E's system.

The center of PG&E's backbone transmission system—the Bay Area loop—connects the Line 400 terminus at the Antioch Terminal to the Line 300 terminus at the Milpitas Terminal. In addition, the Bay Area loop connects the northern and southern backbone systems to pipelines connected to PG&E's underground storage facilities and to PG&E's major local transmission lines in the Bay Area. PG&E's northern backbone system stretches from the California border near Malin, Oregon, south to the Antioch Terminal (Line 400) and to the Panoche Meter Station (Line 401), a distance of approximately 500 miles. Line 2 runs a shorter distance, from the San Francisco Bay Area to the Panoche Meter Station, parallel to Line 401.

PG&E's facilities on the Baja Path (Line 300) are aging. Most of the facilities on Line 300 are over 50 years old, and portions of Line 300 have required repair. PG&E's facilities on the Redwood Path (Lines 400, 401 and 2) also are aging and many of these facilities are almost 40 years old.

There are two requirements for a successful pipeline safety program. The first requirement is that the pipeline operators comply with the federal requirements for pipeline integrity management. There have recently been serious concerns expressed by the CPUC. In its March 17, 2011 "ORDER TO SHOW CAUSE WHY PACIFIC GAS AND ELECTRIC COMPANY SHOULD NOT BE FOUND IN CONTEMPT, AND WHY PENALTIES SHOULD NOT BE IMPOSED, FOR FAILURE TO COMPLY WITH COMMISSION ORDER the Commission states:

"PG&E's Report raises additional questions because PG&E is unable to locate records to support the MAOP it is using for 8% of its pipeline installed prior to July 1, 1970, and even more troublingly for 7% of its pipeline installed after that date. In sum, after a multi-month search effort, PG&E is currently operating 8% of its natural gas transmission system without documents supporting the purported MAOP. Further, undermining confidence in the Strength Test Pressure Reports that it has found, PG&E admits that for 270 miles out of 1,018 miles it claims to have complete pressure test records, the Strength Test Pressure Report footage tested does not correspond to the pipeline High Consequence footage.

Rather than follow the ordered two-step, pipeline-component specific analysis, it appears that PG&E has instead opted to rely on the historical highest operating pressure. PG&E contends that its understanding of the Commission's intent was to provide valid pressure test records or "the determination of MAOP based on the historical high operating pressure." In its Report, PG&E provides no citation in support of its understanding that the Commission authorized the use of historical high operating pressure to validate MAOP, and the plain words of the Commission's order and the NTSB Safety Recommendations appear inconsistent with PG&E's interpretation.

The NTSB, alarmed at the discrepancies in PG&E's as-built drawings, issued urgent Safety Recommendations directed at review of "traceable, verifiable, and complete" as-built drawings and pipeline system components and, based on the reliable pipeline specifications, a determination of the valid MAOP. The Commission then adopted these Safety Recommendations and ordered PG&E to comply.

In light of this history, it appears that PG&E's interpretation is contrary to the NTSB Safety Recommendations and the Commission's order because PG&E relies on historical highest operating pressure as a substitute for actual pipeline component analysis. PG&E has provided no evidence that these historical pressure levels are the functional equivalents of the two-step process recommended by the NTSB. Similarly, PG&E's Report shows no evidence that it conducted an "aggressive and diligent search for as-built drawings" or that it attempted to determine a valid maximum allowable operating pressure based on the weakest component in each pipeline segment.

Many of these same concerns were expressed in the January 1, 2008 audit results released by the Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety on PG&E Integrity Management Program.[1]

The second element of a successful pipeline integrity management program is having enough resources to enforce the program. In 2004, California had just seven inspectors prompting a sternly worded letter from the federal pipeline agency to Public Utilities Commission Chairman Michael Peevey about California's "very programmatic deficiencies." The state's gas safety efforts "continue to be negatively impacted by the low number of on-site audits," Western administrator Chris Hoidal warned in the January 2006 letter. He said the state's deficient inspection regimen "not only reduces public safety, but lowers the amount of federal funds allocated to your pipeline safety program." Carl Weimer, head of a pipeline watchdog group, the Pipeline Safety Trust, agreed that federal officials have not been doing enough to make sure states such as California enforce safety rules. The federal pipeline safety agency "not only needs to make sure the regulators are looking over the industry's shoulder, it needs to look over the other regulators' shoulder to make sure that they are doing their job," Weimer said. "But they just all want to get along."

California's per-mile pipeline safety record in the past decade ranks it just 32nd among the 48 states that do enforcement for the federal government, according to records compiled by the U.S. Pipeline and Hazardous Materials Safety Administration. From 2000 to 2009, California averaged 11 "significant" incidents a year - about 1 per 10,000 miles of pipeline. A significant incident is defined as one involving a death or losses exceeding $50,000. From 1997 to 2006 California had 23 significant incidents for an incident rate of 1.9 in 10,000. The injury rate for the same period was 3.3 in 100,000 and the death rate was 1.6 in 100,000. All of these rates are above the CEQA significance rate that staff normally considerers a significant impact. The current death rate with the San Bruno incident not including any other deaths over a ten year period would be would be 4.8 in 100,000.

Anyone who would state that the current regulatory program in California is adequate has probably not read the paper for several months or followed the current proceedings at

[1] See Potential Issues Summary in Appendix A

the CPUC. California's pipeline safety integrity management program is broken. PG&E does not follow the safety protocols and the CPUC lacks the resources to routinely inspect and enforce the program.

1. What testing has PG&E performed on lines 303 and 400 within the past ten years?

There are several high consequence areas that appear to be under review for line 303 and Line 400 in the Oakley area.[2] The CPUC audit letter of concern for 2008 stated, *"Per the BAP, Line-400 (M.P. 82.33-142.61) was due for an ILI assessment in 2008. It had been selected for ILI due to the line being piggable and it having more HCA pipe than most piggable sections of Line 400. Although this segment had been scheduled for an ILI assessment in 2008, it was not performed in 2008. An exception report dated May 6, 2010 and approved by the Manager of Integrity Management on May 21, 2010, after the scheduled assessment year had been exceeded,* ***moved the assessment to 2010 and converted the assessment method to ECDA.*** *The exception report noted the change to 2010 was made because the segment did not meet all conditions per RMP-06, Section 5.4 (less than 5 miles of HCA, less than 1 mile of tape coating, and it does not have poor pipe condition reports) and "…to better level workload and funding requirements for Integrity Management and allow time for ECDA pre-inspection work to occur*."

PG&E's reports that , *"Line-400 was initially scheduled for In-Line Inspection (ILI) in 2008. However, after re-examination, PG&E determined that this line should be assessed using External Corrosion Direct Assessment (ECDA) in December 2009. Even though an exception report was filled out when the assessment method was changed, per the decision making flow chart in PG&E's Risk Management Procedure RMP-06 "Integrity Management Program" (RMP-06) Section 4.5, an exception report was not required since L-400 did not meet all the criteria for an ILI assessment. Line-400 ECDA was completed in 2010."*[3]

PG&E reported in 2009 that Line 303 was being prepared for a smart pig run in 2008.[4]

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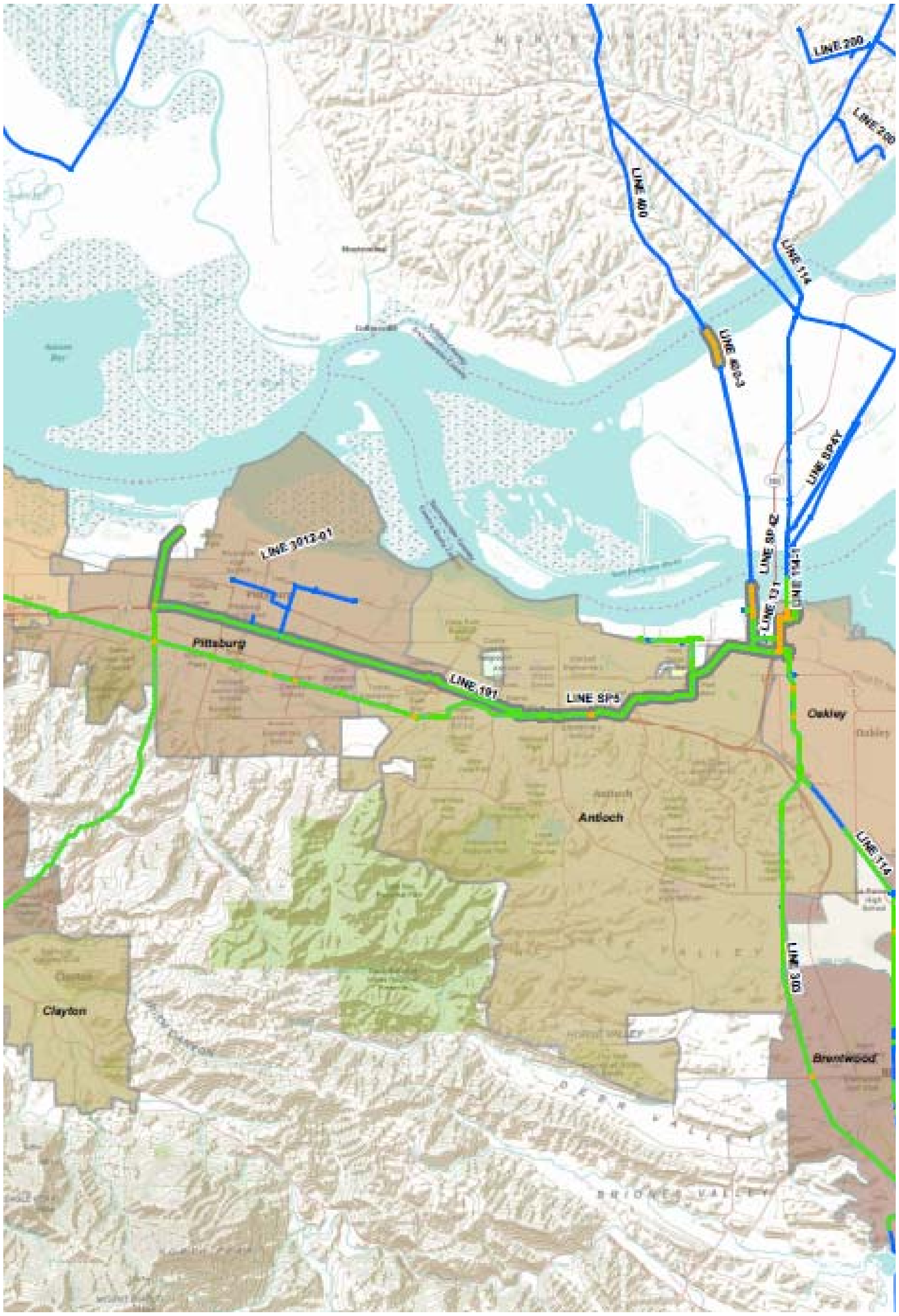
[2] http://www.pge.com/includes/docs/pdfs/myhome/edusafety/systemworks/gas/latestupdates/filingmaps/Map%2023.pdf

[3] http://docs.cpuc.ca.gov/PUBLISHED/Graphics/128919.pdf

[4] http://www.cpuc.ca.gov/NR/rdonlyres/1150A3F6-7CF4-4349-9E2B-A84CB5D21BFF/0/2007PGEGTSRiskManagementAnnualReport.pdf



PG&E Gas Transmission Pipeline

- Natural Gas Transmission Pipelines (Pipelines)
- Pipelines in HCAs with Pressure Test Records and or Section 619(c) Documentation
- Pipeline Segments in High Consequence Areas Under Review
- Reduced Pressure Zones
- 2011 Testing and Replacement Plan

[5]2. If PG&E has not performed hydrostatic testing on line 303 or line 400 are there any known plans for such testing to occur and if so, when will this occur?

PG&E's March 15, 2011 Report to the CPUC indicates that one .87 mile section of Line 400-3 will be hydro tested in 2011. It is not clear from the documents where that section is. Because of the age of Line 400 and Line 303 it is unlikely that they were hydro tested but they may have been. MAOP was probably established by historical operating pressure.

Route No	# of Tests*	Miles Targeted	Pipe Miles to be Tested/ Replaced in 2011	Proposed Action
L-021A	2	0.09	3.55	Hydro test two sections
L-101	4	0.29	0.79	Hydro test four sections
L-105A	2	3.86	5.35	Hydro test two sections
L-105A-1	0	0.004	0.004	Replace one small segment
L-105C	1	1.57	1.76	Hydro test one section
L-105N	4	4.29	14.49	Hydro test four sections
L-107	2	1.86	3.89	Hydro test two sections
L-109	0	1.38	2.00	Replace pipe from 2011 to 2014
L-114	1	0.06	0.06	Replace one small segment
L-131	5	4.53	16.61	Hydro test five sections
L-132	8	30.86	44.34	Hydro test eight sections
L-132A	1	0.81	1.46	Hydro test one section
L-147	1	0.96	3.23	Hydro test one section
L-153	4	19.73	19.73	Hydro test four sections
L-191	2	3.95	7.37	Hydro test two sections Replace one small segment
L-300A	23	38.36	51.63	Hydro test 23 sections
L-300A-1	1	0.61	0.61	Hydro test one section
L-300B	22	33.43	55.97	Hydro test 22 sections
L-301G	1	0.02	0.61	Hydro test one section Replace two small segments
L-400	7	0.74	11.51	Hydro test seven sections
L-400-3	1	0.87	4.01	Hydro test one section
SP - 3	2	0.49	5.75	Hydro test two sections Replace two small segments
SP - 5	1	3.05	3.87	Hydro test one section
0821-01	0	0.002	0.002	Replace one small segment
	95	**151.83**	**258.60**	

3. Are there existing known conditions/flaws/defects regarding lines 303 and 400? If so, identify and describe each such condition/flaw/defect.

[5] http://www.pge.com/includes/docs/pdfs/myhome/edusafety/systemworks/gas/latestupdates/filingmaps/Map%2023.pdf

I was unable to locate any records for any testing at all on these pipelines but I currently have an informal records request with the CPUC and will release that information unless it is confidential.

4. What is the maximum operating pressure on line 303 and on line 400?

Line 303 from the Antioch Terminal to the Brentwood Terminal is a 36 inch natural gas line. Its Maximum allowable Pressure is 720 PSIG and its design pressure is 720 PSIG. PG&E has operated the line up to the maximum operating pressure of 720 PSIG.[6]

Line 400 form Buckeye Creek to the Antioch Terminal is listed as 36 inch in diameter. The pipelines MAOP is 975 PSIG and its design pressure is 975 PSIG. PG&E operates the line at the MAOP of 975PSIG.

There have recently been serious concerns from State regulators about PG&E's justification for the maximum operating pressures currently used for many of its pipelines as mentioned above,

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[6] http://www.cpuc.ca.gov/NR/rdonlyres/98DC029C-6A77-4AB4-9E3B-3721A004F28F/0/01MAOPValidationReport_final_March152011.pdf Appendix A page 15

The NTSB, alarmed at the discrepancies in PG&E's as-built drawings, issued urgent Safety Recommendations directed at review of "traceable, verifiable, and complete" as-built drawings and pipeline system components and, based on the reliable pipeline specifications, a determination of the valid MAOP. The Commission then adopted these Safety Recommendations and ordered PG&E to comply.

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5. To what extent (stated in numbers) would addition of OGS increase the pressure on line 303 and on line 400? Explain whether, and how, these increases are in conformance with applicable laws, ordinances, regulations, and standards.

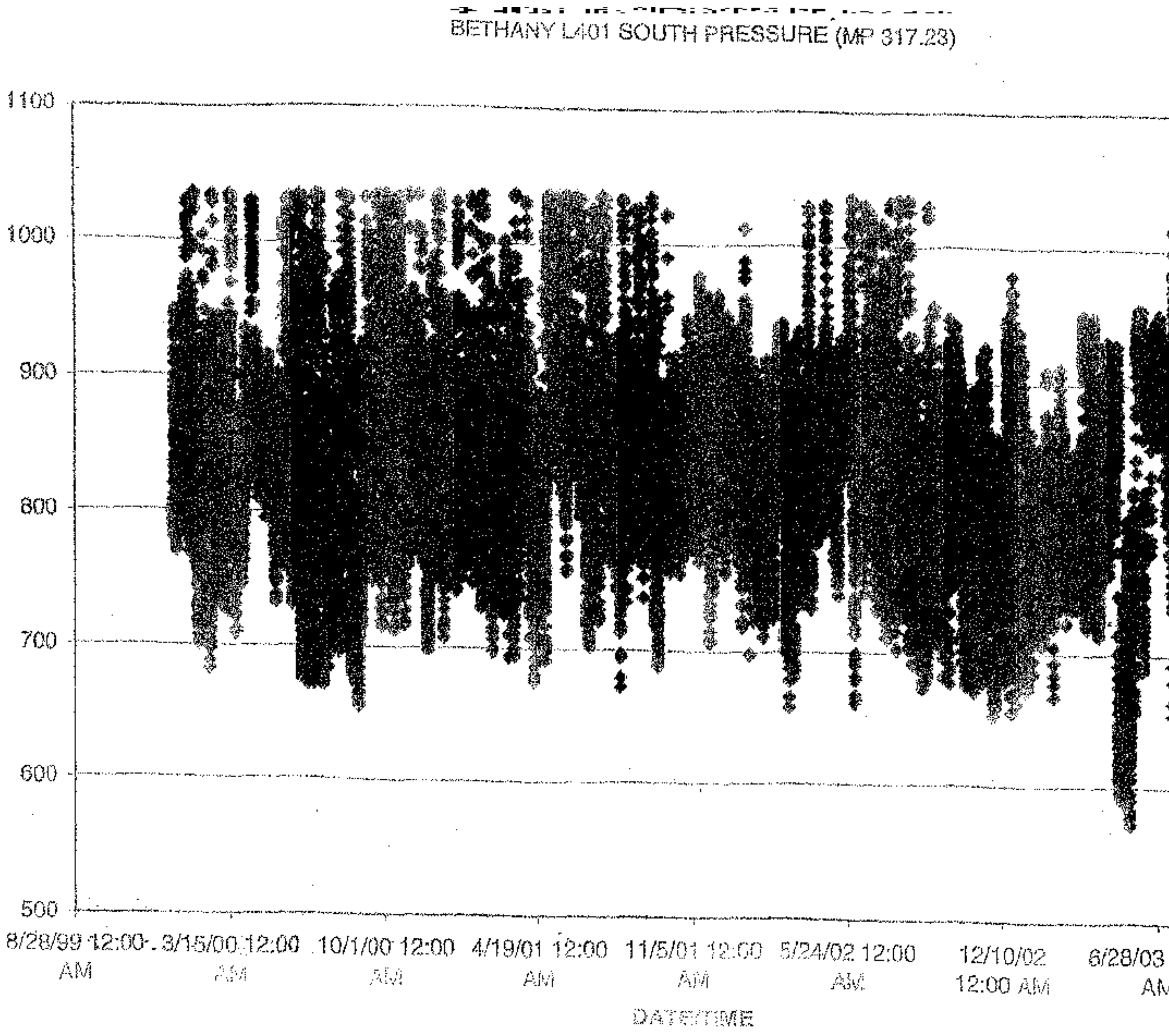
6. Will increased gas pressure affect/exacerbate existing conditions on line 303 or line 400? If so, explain the response.

A properly functioning natural gas pipeline that has been adequately maintained including all of pressure relief valves and other gas line components should be able to function without incident. Without testing, maintenance, pressure fluctuation and gas valve records it is impossible to determine. PG&E's method of establishing MAOP is under question and they have lost numerous records. We would need to see the method used to calculate MAOP and the operating and testing records to determine if the line is safe.

7. Given that OGS might have numerous startups/shutdowns and ramping up and down over the course of any given year in response to various dispatch orders, would line 303 or line 400 be adversely affected by corresponding pressure changes?

Pressures in pipelines are never constant: changes in flow, temperature, the sudden closure of a valve, etc., will cause pressure fluctuations. Pipeline design standards recognize overpressures are inevitable, and they are accommodated in the allowances for 'pressure surges' or 'incidental pressures': most codes allow 10% to 15% overpressures. Without the historical records for these pipelines any conclusion would be speculative.

Below is a record of pressure fluctuations for Line 401 at the Bethany Compressor Station. Line 401 is the companion backbone line to Line 400. As can be seen Line 401 has had extreme pressure fluctuations and has exceeded its MAOP many times. If Line 400 has similar operating characteristics then there could be a problem.



Appendix A

On January 1, 2008 the **Pipeline and Hazardous Materials Safety Administration** issued a Gas Integrity Management inspection of PG&E's protocol for integrity management. Below are some of the potential issues identified by the **Pipeline and Hazardous Materials Safety Administration** on PG&E's integrity management protocols:

A.01 Program Requirements

A.01.d. Review HCA records to verify that the operator completed identification of pipeline segments in high consequence areas by December 17, 2004. [§192.907 and §192.911(a)

ISSUE: We were unable to confirm if all HCA segments existing in 2004 were added to the baseline assessment by December 17, 2004. In addition, we are concerned there may be other MOP segments that are 20% transmission, which may not have been included in the baseline assessment. We requested that PG&E provide information related to a study being performed by the company to confirm this, but PG&E indicated no documentation was available. 49 Code of Federal Regulations (CFR), Part 192,
§192.947(d) requires such documentation to be maintained and available for review during an inspection.[7]

A.02 Potential Impact Radius

For gases other than natural gas, verify that the operator has documented processes for the use of ASME B31.8S-2004, Section 3.2 to calculate the impact radius formula [§192.903 Potential Impact Radius, §192.905(a)]

ISSUE: PG&E has no requirement to use the 0.73 factor for rich natural gas.[8]

Identified sites must include the following: [§192.903 Identified Sites, §192.905(b)]
i. Outside areas or open structures occupied by 20 or more people on at least 50 days in any 12
month period (days need not be consecutive),
ii. Buildings occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month
period (days and weeks need not be consecutive), and

[7] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 5
[8] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 7

iii. Facilities occupied by persons who are confined, have impaired mobility, or would be difficult to
evacuate.

ISSUE: PG&E RMP-06 didn't list the sources for the data selected in identifying the identified
sites.[9]

A.03.b. Identified sites must be identified using the following sources of information: [§192.905(b)]
i. Information from routine operation and maintenance activities and input from public officials with
safety or emergency response or planning responsibilities
ii. In the absence of public official input, the operator must use one of the following in order to
identify an identified site:
1. Visible markings such as signs, or
2. Facility licensing or registration data on file with Federal, State, or local government agencies, or
3. Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public

ISSUE: PG&E has no process for assuring that any HCA information received from sources outside the IM Group is properly and timely tracked, documented, and integrated into the BAP.[10]

5) ***A.05 Identification Using Potential Impact Radius (Method 2)*****A.05.a**
. Verify the integrity management program includes piping locations as high consequence areas if
the area within a potential impact circle contains 20 or more buildings intended for human occupancy:
[§192.903 High Consequence Area (2)(i)]
i. As an option for PIRs greater than 660 feet, the definition of high consequence area may be based
on a prorated building count for buildings intended for human occupancy within a distance of 660
feet (200 meters) from the centerline of the pipeline as calculated using the following formula:
[§192.903 High Consequence Area (4)]
Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]2 or

[9] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 9
[10] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 10

Building Count within 200 meters = 20 x [200 (m) / PIR (m)]2
1. If the option for use of a prorated number of buildings has been used for identification of
high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. [§192.903 High Consequence Area (4)]

ISSUE: PG&E is not using prorating. PG&E is using MOP instead of MAOP to determine where HCA segments exist on its system which is an issue. PG&E is conducting a survey to identify any portions of its pipeline system where MOP and MAOP of line, applied to a given segments characteristics (i.e., pipe wall thickness) would render the segment as being 20% transmission and subject to IM, Subpart O requirements. This may result in additional HCAs being identified. Such an identification should have occurred much earlier in the program. We requested that PG&E provide copies of updates it has received from its vendor (Dan Curtiss – MEARS) related to the survey. However, PG&E refused to provide the updates although the audit team believes they are reviewable documents (CFR §192.947(d)).[11]

A.06 Identification and Evaluation of Newly Identified HCAs, Program Requirements

Review the operator's integrity management program to verify processes are in place for evaluation of new
information that may show that a pipeline segment impacts a high consequence area. [§192.905(c)]

A.06.a. Verify the operator's integrity management program includes documented processes for how new
information that shows a pipeline segment impacts a high consequence area is identified and integrated
with the integrity management program. The program is to identify and analyze changes for impacts on
pipeline segments potentially affecting high consequence areas. Issues the program must consider include
but are not limited to:[§192.905(c)]

i. Changes in pipeline maximum allowable operating pressure (MAOP),
ii. Pipeline modifications affecting piping diameter,
iii. Changes in the commodity transported in the pipeline,
iv. Identification of new construction in the vicinity of the pipeline that results in additional
buildings intended for human occupancy or additional identified sites,
v. Change in the use of existing buildings (e.g., hotel or house converted to nursing home),
vi. Installation of new pipeline,
vii. Change in pipeline class location (e.g., class 2 to 3) or class location boundary,
viii. Pipeline reroutes

[11] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 14

ix. Corrections to erroneous pipeline center line data.

ISSUE: PG&E needs to modify its RMP-06 (Sections 17.2 and 17.3) to add a process to more thoroughly review new HCAs in order to identify any that existed during previous reviews, but were somehow not identified and missed from inclusion into the IMP. Such a review should document the reason(s) for the HCA being added to the IMP as well as a determination of why the HCA may not have been identified during the last review. The review process could help PG&E identify program deficiencies (i.e., errors in pipeline data, buffers applied, etc.) that could be attributing to all HCAs not being identified and included in it IMP.[12]

B.02 Prioritized Schedule

Verify that the BAP contains a schedule for completing the assessment activities for all covered segments;
and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule.
[§192.917(c), §192.919(c) and §192.921]
B.02.a. Verify that the BAP schedule includes all covered segments not already assessed.
[§192.921(a)]

ISSUE: PG&E's GIS has specific dates for reassessments; however, not for assessments. PG&E is not updating its BAP with specific dates and is only documenting the calendar years for reassessments and assessments still to be performed even those that are near term. Pipeline and Hazardous Materials Safety Administration (PHMSA) FAQ-39 suggests specific dates be indicated in BAP updates as assessments come closer in time to being performed.[13]

B.02.c. Verify that covered segments meeting the following conditions are prioritized as high-risk
segments.
i. Segments that contain low frequency resistance welded (ERW) pipe or lap welded pipe that satisfy
the conditions specified in ASME B31.8S-2004, Appendix A4.3 and ASME B31.8S-2004,
Appendix A4.4, and any covered or non-covered segment in the pipeline system with such pipe
has experienced seam failure, or operating pressure on the covered segment has increased over the

[12] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 16
[13] [13] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 22

maximum operating pressure experienced during the preceding five years. [§192.917(e)(4)]
ii. Covered segments that have manufacturing or construction defects (including seam defects) where
any of the following changes occurred in the covered segment: operating pressure increases above
the maximum operating pressure experienced during the preceding five years; MAOP increases; or
the stresses leading to cyclic fatigue increase. [§192.917(e)(3)]

ISSUE: PG&E RMP-06, Section 4.3, does not include the requirement to prioritize LFERW as high risk for any "covered or non-covered segment where in the pipeline system …has experienced seam failure." (i.e., it speaks to covered, but not to non-covered segments.)[14]

B.02.e. Review the operator's implementation progress to date and verify that: [§192.921]
i. Assessments scheduled for completion by the date of the inspection were in fact completed.
ii. Assessment methods used for completed assessments were as described in the plan.
iii. The date assessment field activities were completed is recorded [so the operator understands the
time frame allowable for compliance with the provisions of §192.933].

ISSUE: PG&E needs to have date specific information, in the BAP as assessment dates approach. Also, for DA, PG&E is considering the end of its ECDA Step 3 as being the end of its assessment and counting the mileage as completed for DA. However, per PHMSA FAQ-34, the baseline assessment is not considered complete until "the last direct examination associated with direct assessment is made…" Per NACE RP0502-2002, Figure 7, direct examinations for process validation, performed per NACE RP0502, Section 6.4.2, are the last direct examinations associated with direct assessment. Therefore, it appears that PG&E may be incorrectly counting completed DA mileage within its IMP.[15]

B.03 Use of Prior Assessments

If prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of
§192.921(a) and that remedial actions have been carried out to address conditions listed in §192.933. Prior
assessments are those that were completed prior to December 17, 2002. [§192.921(e)]

[14] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 23
[15] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 24

B.03.a. Verify that threats to these pipeline sections were identified as required under §192.919(a).

B.03.a. Inspection Results *(Type an X in the applicable box below. Select only one.)*

ISSUE: The PG&E LTIMP for Line 300A South identified a Hard Spot threat; however, no assessment has been conducted for this threat. (Line 172 had an identified hard spot failure and an ILI tool capable of hard spot detection was run on that line on 5/24/2005.) A corrosion growth rate of 1 mil/year was used on 300A South (amended report) while 12 mils/year was used on Line 57B because no "detailed CP information" was used by the corrosion engineer. PG&E needs to justify the corrosion growth rates used in determining reassessment intervals. As noted in RMP-09, Section 6.2.2.3, "*Exceptions: ASME B31.8S (2001) page 63, Table B1, shows average corrosion rates related to soil resistivity which are provided in Table 6.2.1. Other corrosion rates that are scientifically supported may also be used. The Manager of CE&DA shall approve using these rates…*" Therefore, please provide the justification for the 1 mil/year corrosion rate identified for Line 300A South and the approval of the manager of CE&DA. The compliance file for Line 57B did not contain documentation of what threats, other than EC, were considered, evaluated and/or assessed on Line 57B.
PG&E did not have LTIMPs for Line 2 and Line 57 because re-assessments were performed in 2008 before the LTIMP could be assembled. PG&E should have had the LTIMPs in place at least by 2007 to identify and address all other threats not assessed by the ILI run.[16]

B.04 New HCAs/Newly Installed Pipe

Verify that the operator updates the baseline assessment plan for new HCAs and newly installed pipe.
[§192.905(c), §192.921(f), §192.921(g)]
B.04.a. If new HCAs have been identified or new pipe has been installed that is covered by this subpart,
verify that applicable segment(s) have been incorporated into the operator's baseline assessment plan
within one year from the date the area or pipe is identified and assessments have been appropriately
scheduled and/or completed. [§192.905(c)]

ISSUE: PG&E has no formal process to track and integrate new HCAs that are not part of the annual review into the BAP. The date that the HCA is discovered should be better recorded in order to confirm compliance. Finally, the USRB team had a concern that PG&E is not performing any investigations to confirm, when an HCA is newly identified, if the HCA is one that existed in 2004 (or when other reviews were performed prior to the date of discovery of the HCA) but was somehow missed. Such an investigation could help PG&E better validate its HCA identification process.[17]

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[16] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 26

C.01 Threat Identification

Verify that the operator identifies and evaluates all potential threats to each covered pipeline segment.
[§192.917(a)]
C.01.a. If the operator is following the prescriptive or performance-related approaches, verify that the
following categories of failure have been considered and evaluated: [§192.917(a) and ASME B31.8S-2004,
Section 2.2]
i. external corrosion,
ii. internal corrosion,
iii. stress corrosion cracking;
iv. manufacturing-related defects, including the use of low frequency electric resistance welded
(ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4) and ASME B31.8S-2004, Appendix A4.3];
v. welding- or fabrication-related defects,
vi. equipment failures;
vii. third party/mechanical damage [§192.917(e)(1)],
viii. incorrect operations (including human error),
ix. weather-related and outside force damage,
x. cyclic fatigue or other loading condition [§192.917(e)(2)],
xi. all other potential threats.

ISSUE: Protocol C.01.a.xi requires "all other potential threats" be identified and evaluated;however, PG&E has not developed a process for evaluating the threat of equipment failure and is not mandating hard spots (RMP-06, Section 3) to be assessed, although they have been identified as a possible threat, before considering assessment or mitigation efforts are completed. 49 CFR §192.917(a) states in part: "An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME…" Per 49 CFR §192.917(c), an operator must conduct a risk assessment that considers the threats and aids in prioritizing the covered segment for the baseline and continual assessments. For equipment threats, ASME B31.8S, Section A6.2 (page 49) specifies minimal data sets to be collected and reviewed before a risk assessment can be conducted. PG&E has not collected this data set, nor attempted to identify particular equipment threats on any given segment.[18]

C.02 Data Gathering and Integration

[17] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 29
[18] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 35

Verify that the operator gathers and integrates existing data and information on the entire pipeline that
could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and
integrated. [§192.917(b)]
C.02.a. Verify that the operator has in place a comprehensive plan for collecting, reviewing, and analyzing
the data. [ASME B31.8S-2004, Section 4.2 and ASME B31.8S-2004, Section 4.4]

ISSUE: PG&E has identified Equipment Failure as a threat, although it's unclear how this threat is assessed and/or if previous equipment related data has been integrated into the BAP. PG&E RMP-06, Section 2.4, mentions a procedure for determining equipment threat; however, the procedure doesn't exist according to PG&E. PG&E did not integrate equipment data in BAPs established in 2004.[19]

C.02.f. Verify that individual data elements are brought together and analyzed in their context such that the
integrated data can provide improved confidence with respect to determining the relevance of specific
threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data
integration includes:
i. A common spatial reference system that allows association of data elements with accurate
locations on the pipeline [ASME B31.8S-2004, Section 4.5];
ii. Integration of ILI or ECDA results with data on encroachments or foreign line crossings in the
same segment to define locations of potential third party damage [§192.917(e)(1)].

ISSUE: PG&E is not currently entering USA information into its GIS, nor is it entering any patrol findings that could impact transmission pipelines. (PHMSA FAQ-81 requires: "Information related to determining the potential for, and preventing damage due to excavation, including damage prevention activities…" be integrated in performing a continual evaluation of pipeline integrity.) PHMSA FAQ-240 (paragraph 4) also speaks to this, as well as ASME B31.8S, Section A7.2 also requires one-call to be integrated.[20]

C.03.e. Verify that adequate time and personnel have been allocated to permit effective completion of the
selected risk assessment approach. [ASME B31.8S-2004, Section 5.7(b)]

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[19] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 38
[20] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 40

ISSUE: Exception report had to be issued due to unavailability of personnel from steering committees to meet due to other (parcel entry) work having to be done at the end of the year.[21]

C.04 Validation of the Risk Assessment

Verify that the integrity management program identifies and documents a process to validate the results of
the risk assessments. [§192.917(c) and ASME B31.8S-2004, Section 5.12]

C.04.a. Verify that the validation process includes a check that the risk results are logical and consistent
with the operator's and other industry experience. [§192.917(c) and ASME B31.8S-2004, Section 5.12]

C.04.a. Inspection Results *(Type an X in the applicable box below. Select only one.)*

No Issues Identified

X Potential Issues Identified *(explain in Statement of Issue)*

Not Applicable *(explain in Statement of Issue)*

C.04.a. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the
Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a
one-to-one correlation between issues and issue categories. No issue should be related to more than one issue
category. No issue category should be related to more than one issue.)*

ISSUE: PG&E IMP Consequence Committee did not meet in 2008 or 2009. PG&E staff indicated that per PG&E RMP-06, Section 18, Exception Process allowed for the annual meeting requirement to be waived. It would appear that an annual meeting is required by code since RISK, of which consequence is one factor, has to be evaluated at least annually. PG&E believes the meetings in 2008 and 2009 were not necessary since consequences, which are driven by PIC calculations, do not significantly change.
In addition, the 2009 minutes from the meeting of the PG&E IMP Ground Movement Committee did not clearly indicate that all items required to be reviewed by PG&E RMP-01, Section 6.2.5 were reviewed (i.e., LOF x COF list was unavailable during the meeting so only the LOF list was reviewed.) FAQ-234 and ASME B31.8S, Section 5.8 require annual review of RISK.
Finally, a PG&E e-mail, detailing meeting minutes from the 2009 meeting of PG&E IMP External Corrosion Committee, lacks any detail or support for the decision making process used to modify PG&E RMP-02.[22]

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[21] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 43

[22] http://www.cpuc.ca.gov/NR/rdonlyres/307D1C31-143F-4B95-B4DB-82379210C7CC/0/2010_Audit_Protocol_for_PGE_Integrity_Management_Program.pdf Page 46

D.02.d. Verify that the operator **identifies ECDA Regions** based on the use of data integration results applied to specified criteria. [NACE RP0502-2002, Section 3.5]

ISSUE: PG&E groups all casings into only 2 regions - Region 3 and Region 8, in which the later region was recently added due to temperature gradient, SCC, and condensate concerns. Casings are aggregated by region and year for all segments (N-Segs) on which assessments are performed in a given year. Casing assessments are performed from an aggregated pool from which digs are then initiated. PG&E's grouping of its casings does not follow the March 1, 2010, PHMSA Guidance, "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs." The guidance developed guidelines for establishing ECDA regions for cased pipe. Six attributes required separate ECDA regions and eleven attributes must be considered when determining ECDA regions, but alone does not always require a separate ECDA region. During an April 2010 workshop, PHMSA provided additional clarification on guidance related to casing assessments and reinforced its expectation for operators to utilize the guidance in completing casings assessments by December 17, 2010. During the audit, PG&E staff stated that PG&E does not plan on utilizing the March 1, 2010, in regionalizing casings per the PHMSA Guidance.
PG&E schedules Regions 1 and 2, along with 5, for excavation as indirect assessments are received, whereas other casing regions are grouped together and dug from a "pool" of potential tool dig sites. This process is not allowed for by 49 CFR §192 or NACE RP0502. (This process fails to consider CP variations and CP historical deficiencies applicable to casings on different segments.)[23]

D.04 ECDA Direct Examination

Verify that the ECDA Direct Examination process complies with ASME B31.8S-2004, Section 6.4 and NACE RP0502-2002, Section 5 to collect data to assess corrosion activity and remediate defects discovered. [NACE RP0502-2002, Section 5.1.1 and §192.925(b)(3)]

D.04.a. Verify that the operator performs excavations and data collection in accordance with NACE RP0502-2002, Section 5.3, NACE RP0502-2002, Section 5.4, NACE RP0502-2002, Section 5.10 and NACE RP0502-2002, Section 6.4.2.

i. Verify that the operator makes excavations based on priority categories described in NACE RP0502-2002, Section 5.2. [NACE RP0502-2002, Section 5.3.1]

ii. Verify that the operator identifies and implements minimum requirements for data collection, measurements, and recordkeeping, to evaluate coating condition and significant corrosion defects

[23] ID at 52

at each excavation location. [NACE RP0502-2002, Section 5.3, NACE RP0502-2002, Section 5.4,
NACE RP0502-2002, Appendix A, NACE RP0502-2002, Appendix B, and NACE RP0502-2002,
Appendix C]
iii. Verify that the number and location of direct examinations complies with NACE RP0502-2002,
Section 5.10 and NACE RP0502-2002, Section 6.4.2

ISSUE: PG&E needs to clarify RMP-09, Section 5.3.1 (page 45 of 204). It discusses a typical length of 12-feet, centered on the indication, for the purpose of exposing approximately 10-feet of pipeline for direct examination. However, it appeared from records review that only 10-foot excavations are being performed.
In PG&E RMP-09, Section 5.6, Table 5.6.4, the Data Elements 1.9 & 1.10 are found in the table as being "Required". However, those Data Elements are not found in the "Direct Examination Data Sheet (Casing Only) Page 1 of 1, Form H.
In PG&E RMP-09, Section 5.3.3.1, Table 5.3.1 states that PG&E is conducting just one addition dig if there was an immediate and schedule found and not the addition two digs for the first time through as required in NACE RP0502, Section 5.10.2.2.2 and PG&E RMP-09, Section 5.3.3.1. Example in PG&E RMP-09 shows how PG&E interprets NACE RP0502, Section 5.10.2.2.2.
In PG&E RMP-09, Section 5.3.2.1, it states in part that PG&E does reprioritize even immediate digs after sampling "some" immediate indications. PG&E is not following NACE RP0502 requirement to dig ALL immediate indications and to not reprioritize indications the first time ECDA is applied to a given segment. PG&E presented a white paper that essentially considers "should" from the NACE RP0502 document as a suggestion and not requirement.[24]

D.04.b. Verify that the operator determines the remaining strength at locations where corrosion defects are
found. Any corrosion defects discovered during direct examinations must be remediated in accordance with
§192.933. [§192.925(b)(3)(ii), §192.933, and NACE RP0502-2002, Section 5.5]

ISSUE: PG&E RMP-09, Section 5.7, and all related forms need to be modified to mandate a10% pressure reduction, as required by PG&E Utility Operation Standards 4134, if mechanical damage is found during the direct examination process.[25]

D.04.f. As appropriate, verify the basis upon which the operator may reclassify and reprioritize indications
in accordance with any of the provisions that are specified in NACE RP0502-2002, Section 5.9.

[24] ID. at 57
[25] ID at 58

[§192.925(b)(3)(iv)]

ISSUE: PG&E presented a "MEMO TO FILE", dated May 20, 2010, in which it allows for reclassification or re-prioritization of indications, regardless if assessment is performed the first time or subsequent assessment. This goes against NACE RP0502 (2002) which discourages such a practice. Also, PG&E's definition of first time application of ECDA is inconsistent with NACE RP0502, Section 5.8.4.2 which discusses "initial ECDA" vs. PG&E's "first time ECDA is used." It should also be noted that the May 20, 2010 memo, which was created during the audit, could not retroactively apply to any reprioritizations performed prior to its creation since justification had not been provided for such reprioritizations.[26]

D.04.g. Verify the operator establishes and implements criteria and internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications. [§192.925(b)(3)(iii), §192.909, and §192.911(k)]

ISSUE: PG&E did not have a written process which clarifies the criteria and internal notification procedures for any changes in the ECDA Plan as required by the protocol.[27]

D.05.c. Verify that performance measures for ECDA effectiveness have been defined and are monitored.
[§192.925, §192.945(b) and NACE RP0502-2002, Section 6]
i. Verify that at least one additional, randomly selected anomaly location has been excavated for process validation. [NACE RP0502-2002, Section 6.4.2]
ii. Verify that additional criteria have been established and monitored to evaluate long-term program effectiveness such as those identified in NACE RP0502-2002, Section 6.4.3. [§192.945(b) and NACE RP0502-2002, Section 6.4.3]

ISSUE: PG&E provided a copy of a "MEMO TO FILE", dated December 23, 2009, in which the company allows the random effectiveness direct examination location to be chosen from established data sets that contain possible third party damage, possible old corrosion, or other indications that will verify the successfulness of the ECDA process. The memo restates the definition of "Random" as contained in PG&E RMP-09 (Rev 7) as being "Statistics relating or belonging to a set in which all members have the same probability of occurrence…" It provides as examples of sets of indications such as

[26] ID at 59
[27] ID at 59

Scheduled, Monitor, etc. However, another definition (per Encarta Dictionary) defines "random" as:
"done, chosen, or occurring without an identifiable pattern, plan, system, or connection." The USRB team believes PG&E's process for selecting a random confirmation dig conflicts with NACE RP0502, Section 6.4.2 which states in part, "At least one additional direct examination at a **randomly** (emphasis added) selected location shall be conducted to provide additional confirmation that the ECDA process has been successful." Since PG&E's selection process, for selecting locations for determining the effectiveness of its DA process, utilizes established data sets of third party damage or old corrosion to guide in the selection locations, the USRB teams believes it constitutes "an identifiable pattern, plan, or system…" which does not provide for a truly random selection process.[28]

<u>If the operator elects to use ICDA, verify that the operator develops and implements an ICDA plan in accordance with §192.927.</u>

<u>**D.06.a.** Verify that the operator developed a documented ICDA plan [§192.927(c)]</u>

ISSUE: During our audit, we were unable to confirm if the Supervising Engineer, the ICDA Project Manager, and the ICDA Project Engineer had received formal training as required by PG&E RMP-10, Sections 2.3.2, 2.3.3, and 2.3.4, respectively.[29]

<u>**D.06.b.** Verify that the operator's plan contains provisions for carrying out ICDA on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments. [§192.927(c)(5)(iii)]</u>

ISSUE: PG&E RMP-10 does not have an explicit requirement that the ICDA be carried out on the entire pipeline in which covered segments are present. (49 CFR §192.927).[30]

D.08 Dry Gas ICDA Direct Examination

<u>**D.08.a.** Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., identifying locations most likely to have internal corrosion, selection of tools) in implementing the direct assessment stage of the ICDA process. [§192.927(c)(5)(i)]</u>

ISSUE: In PG&E RMP-10, Section 6.2.3, "pipeline operator" needs to be made specific to PG&E personnel responsible.
PG&E RMP-10, Section 6.2.3.1: We believe this section is intended to reference 5.5.9

[28] ID at 64
[29] ID at 66
[30] ID at 66

instead of 5.5.10.
PG&E RMP-10, Section 6.2.5 needs to provide more direction as to how many, and at what locations, additional direct examinations could be performed.[31]

D.08.e. Verify that the operator's plan contains provisions for applying more restrictive criteria for the
direct examination when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]

ISSUE: PG&E indicated it is performing GWUT to inspect non-exposed pipe wall during direct examinations; however, in PG&E RMP-10, Section 6.3.7, this GWUT is stated as
something that "may" be done to augment the direct examination process. The "may" needs to be removed from the section and replaced as a requirement.[32]

D.11.a. Verify that the operator has a process to **gather, integrate, and evaluate data** for all covered
segments to identify whether the conditions for SCC are present and to prioritize the covered segments for
assessment. [§192.929(b)(1)]
i. Verify that the operator's process gathers and evaluates data related to SCC at all sites it excavates
during the conduct of its pipeline operations (not just covered segments) where the criteria indicate
the potential for SCC. [§192.929(b)(1) and ASME B31.8S-2004, Appendix A3.3]
ii. Verify that the data includes, as a minimum, the data specified in ASME B31.8S-2004, Appendix
A3.
iii. Verify that the operator addresses missing data by either using conservative assumptions or
assigning a higher priority to the segments affected by the missing data, as required by ASME
B31.8S-2004, Appendix A3.2.

PG&E RMP-13 does not detail the requirement of ASME B31.8S related to missing data; (D.11.a. iii) requires segments to be prioritized higher or conservative assumptions to be used.[33]

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[31] ID at 72
[32] ID at 74
[33] ID at 81

D.12.b. Verify that the operator's plan specifies an acceptable **inspection, examination, and evaluation plan** using either the Bell Hole Examination and Evaluation Method (that complies with all requirements of ASME B31.8S-2004, Appendix A3.4 (a)) or Hydrostatic Testing (that complies with all requirements of ASME B31.8S-2004, Appendix A3.4 (b)).

i. Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with ASME B31.8S-2004, Appendix A3.4 (b)) within 12 months of the failure, using a documented hydrostatic retest program developed specifically for the affected segment(s), as required by ASME B31.8S-2004, Appendix A3.4.

ISSUE: PG&E RMP-13 does not explicitly require the hydrostatic test required by ASME B31.8S, Appendix A3.4.[34]

E.01 Program Requirements for Discovery, Evaluation and Remediation Scheduling

Verify that provisions exist to discover and evaluate all anomalous conditions resulting from integrity assessment and remediate those which could reduce a pipeline's integrity. [§192.933(a)]

E.01.a. Verify a definition of discovery is provided. [§192.933(b)]

ISSUE: PG&E RMP-06, Section 6.4 has to be made PG&E-specific and detail what PG&E defines as its discovery date. Also, PG&E RMP-06 provides no "discovery of condition" definition for ICDA.[35]

E.01.b. Verify a requirement exists to document the actual date of discovery. [§192.933(b)]

E.01.b. Inspection Results *(Type an X in the applicable box below. Select only one.)*

ISSUE: PG&E RMP-11 does not have an explicit requirement to document the date of discovery using whichever form PG&E may dedicate for the documentation. The same concern applies to PG&E RMP-09 which also does not have an explicit requirement.[36]

E.01.d. If the operator desires to deviate from the timelines for remediation as provided in §192.933 by

[34] ID at 83
[35] ID at 85
[36] ID at 85

demonstrating exceptional performance, verify that the requirements of §192.913(b) have been met and the
safety of the covered segment is not jeopardized. [§192.913(c)(2)](See Protocol F.05)

PG&E not using exceptional performance criteria.[37]

E.02 Program Requirements for Identifying Anomalies

Inspect the operator's program to verify that provisions exist for the classification and remediation of
anomalies that meet the criteria for: (1) Immediate repair conditions; (2) One-year conditions; (3)
Monitored conditions; or (4) Other conditions as specified in ASME B31.8S-2004, Section 7 . [§192.933(c)
and §192.933(d)]
E.02.a. Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon
discovery of all immediate repair conditions. [§192.933(d)(1)]

Although PG&E RMP-11, Section 5.3.3 speaks to reducing pressure to address a safety issue on the line due to an immediate condition; however, the option to shut down the line, or under what situations scenarios the line would be shut-down, is not addressed by the RMP.[38]

E.02.c. Verify provisions exist to record and monitor anomalies that are classified as "monitored
conditions" during subsequent risk or integrity assessments for any change in their status that would require
remediation. [§192.933(d)(3)]

ISSUE: PG&E RMP-11, Section 5.5, does not provide for requirements to record and monitor anomalies classified as "monitored conditions" during subsequent risk or integrity assessments for any changes in their status that would require remediation.[39]

E.03 Operator Response when Timelines for Evaluation and Remediation Cannot be Met

Verify that provisions exist to respond appropriately when the operator is unable to meet time limits for
evaluation and remediation. [§192.933(a)].

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[37] ID at 86
[38] ID at 88
[39] ID at 89

E.03.a. Verify a requirement exists to take a temporary operating pressure reduction or other action that
ensures safety of the covered segment in the event the operator is unable to respond within the timeframes
required by §192.933. [§192.933(a)]
i. Verify a requirement exists to determine the appropriate pressure reduction using ASME B31G, or
"RSTRENG", or reduce pressure to a level not exceeding 80% of the level at the time the condition was discovered. [§192.933(a)]
ii. Verify a requirement exists that when a pressure reduction is to exceed 365 days, a documented
technical justification is developed that explains the reason for remediation delay and demonstrates continuation of the reduction will not jeopardize pipeline integrity. [§192.933(a)]

ISSUE: In PG&E RMP-11, Section 5.3.3, PG&E uses the highest operating pressure, occurring anytime between the time period the pig run is made and the time a pressure reduction is determined as the pressure from which a 20% reduction is made. This does not comply with reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. A provision in 49 CFR §192.933 exists to address circumstances under which a 20% reduction cannot be taken. 49 CFR §192.933 states in part: “An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.”[40]

E.04 Record Review for Discovery, Repair and Remediation Activities

Inspect operator repair and remediation records to verify that remediation activities have been conducted in
accordance with program requirements. [§192.933]
E.04.a. Verify a prioritized schedule exists for evaluation and remediation of anomalies identified during
assessment or reassessment activities. The prioritized schedule must document which of the criteria
specified in §192.933(d) and/or ASME B31.8S-2004 were used as the basis for the schedule. [§192.933(c)
and §192.933(d)]

ISSUE: PG&E RMP-09 requires that the first excavation commence within 180 days of the assessment. It is the goal of 49 CFR §192.933(b) to have discovery of all potentially unsafe conditions from the assessment/re-assessment occur within 180 days and not

[40] ID at 91

just the have the first dig take place within 180 days. 49 CFR §192.933 states in part: "…An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination…"[41]

E.04.b. Verify anomaly discovery was documented within 180 days of completion of the assessment or
reassessment, or else that compliance with the 180-day period was impracticable. [§192.933(b)]
E.04.b. Inspection Results *(Type an X in the applicable box below. Select only one.)*

ISSUE: PG&E RMP-09 gives the contractor 90 days to provide PG&E the results of the indirect examination. PG&E performs its analysis of the indications within 1 month after receipt of data. PG&E then has 180 days from the receipt of the indirect inspection report to perform its first excavation. This process sums up to about 270 days from the completion of the indirect inspection. This does not meet 49 CFR § 192.933(b) which requires that, within 180 days after conducting an integrity assessment, the operator makes a determination if a condition presents a potential threat.[42]

E.04.e. Verify immediate repair conditions have been evaluated and remediated on a schedule established in accordance with the provisions of ASME B31.8S-2004, Section 7. [§192.933(d)(1)]

ISSUE: Under exception report of December 11, 2008, generated by PG&E for N-Seg 101-2008 (Sta 117+36), PG&E did not dig all immediate indications from M.P. 42.24 to 44.61, PG&E examined 4 of the 7 immediate excavations specified by the ECDA IIT. PG&E's exception report stated that enough information had been gained from the examination of the 4 indications that the remaining 3 immediate indications did not need to be examined. However, this does not comply with ASME, B31.8S-2004, Section 7, or 49 CFR, §192.933(d)(1). This finding serves as one example where the USRB team found PG&E to be non-compliant with this protocol. However, based on the copy of PG&E's May 20, 2010 memo, *PG&E Justification of Reprioritization for First Time ECDA*, provided to the team during the audit, the team believes there are potentially more instances in which PG&E may not have evaluated or remediated immediate indications in full compliance with ASME, B31.8S-2004, Section 7, or 49 CFR, §192.933(d)(1).[43]

F.01.d. Verify that the operator periodically reviews the evaluation results to determine if the new
information warrants changes to reassessment intervals and/or methods, and makes changes as appropriate.

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[41] ID at 94
[42] ID at 94
[43] ID at 95

[§192.937]

ISSUE: PG&E performs an annual risk review for every segment, covered and non-covered, to reassess risk. Risk not evaluated in 2009 since the committees didn't meet.[44]

Exceptional performance criteria, to calculate assessment intervals, not currently being used by PG&E.[45]

H.07.a. Verify that an adequate risk analysis-based process is used to determine if an automatic shut-off
valve or remote control valve should be added. [§192.935(c)]
i. Verify that, as a minimum, the following factors were considered: [§192.935(c)]
1. swiftness of leak detection and pipe shutdown capabilities
2. the type of gas being transported
3. operating pressure
4. the rate of potential release
5. pipeline profile
6. the potential for ignition
7. location of nearest response personnel

H.07.a. Inspection Results *(Type an X in the applicable box below. Select only one.)*
No Issues Identified
X Potential Issues Identified *(explain in Statement of Issue)*
Not Applicable *(explain in Statement of Issue)*

H.07.a. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the*
Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a
one-to-one correlation between issues and issue categories. No issue should be related to more than one issue
category. No issue category should be related to more than one issue.)
PG&E has not developed specific guidelines (especially none which consider items listed under H.07.a.) for utilizing in-line valves (although PG&E RMP-06 indicated this was to have been done by 12/31/2009) for pipeline integrity management. PG&E staff could provide no response why the guidelines were not completed by that date.[46]

J.01 Records to be Maintained by the Operator

PG&E could not provide records to show that its steering committees are meeting on an annual basis, as required by PG&E RMP-01, Section 6.2 and PG&E RMP-06, Section 3.4. No meeting minutes from 2007 were provided. In addition, PG&E's records process needs to provide more detail/rational supporting decisions made through the meetings and confirmation that the meetings are conducted, and records reviewed per

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[44] ID at 100
[45] ID at 111
[46] ID at 132

PG&E RMP-01. [EC meeting minutes (07/08/2009 e-mail from Kevin Armato) is an example of this.][47]

K.01 Documentation and Notification of Changes to the Integrity Management Program

Verify that changes to the integrity management program have been handled in accordance with §192.909
of the rule.

K.01.a. Verify that the reasons for program changes have been documented prior to implementation of the
change(s). [§192.909(a)]

PG&E ICDA performed in 2005 and 2007 was done under a draft (framework) procedure. The approval of a new procedure didn't occur until late 2009 early 2010.[48]

K.02.c. Verify the following are provided for by the change procedures: [ASME B31.8S-2004, Section
11(a)]

i. Reason for change
ii. Authority for approving changes
iii. Analysis of implications
iv. Acquisition of required work permits
v. Documentation
vi. Communication of the change to affected parties
vii. Time limitations
viii. Qualification of staff

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There is no written process for communicating changes to vendors (i.e., MEARS) and what follow-up is reviewed to confirm that the changes were properly implemented by the vendor. Time limitations need to also be specified to make certain that changes are communicated well in advance of the expected date when changes are to be put into effect.[49]

L.01.b. Verify that reviews of the integrity management program and the quality assurance program have
been specified to be performed on regular intervals, making recommendations for improvement. [ASME
B31.8S-2004, Section 12.2(b)(3)]

L.01.b. Inspection Results *(Type an X in the applicable box below. Select only one.)*

In Year 2007, PG&E had a review performed by P-PIC; however, it appears that PG&E

[47] Id at 141
[48] Id At 143
[49] ID at 145

did not review the report from P-PIC, and formulate a position/response on its findings, until December 2009 (Rev7 to PG&E RMP-09 mentioned on page 10 of PG&E response). In October 2009, PG&E had an external review done of its ILI and DA but as of the time of the PUC Audit, PG&E had not formulated a position/response on that review's findings. PG&E needs to review the recommendations and act on them in a timely manner.[50]

L.01.c. Verify that corrective actions to improve the integrity management program and the quality
assurance process have been documented and are monitored for effectiveness. [ASME B31.8S-2004,
Section 12.2(b)(7)]

There is no formal process created to document and monitor the effectiveness of corrective actions taken to improve the integrity management program. PG&E essentially considers the change form for PG&E RMP-06 as being the documentation for effectiveness; however, there are no other details as to what exactly was looked at during each annual process to review PG&E RMP-06. Also, no timetables are specified for the changes/reviews of the effectiveness.[51]

M.01.b. Verify provisions for operator internal organizational communication exist to establish
understanding of and support for the integrity management program. [ASME B31.8S-2004, Section 10.3]
M.01.b. Inspection Results *(Type an X in the applicable box below. Select only one.)*
No Issues Identified
X Potential Issues Identified *(explain in Statement of Issue)*
Not Applicable *(explain in Statement of Issue)*
M.01.b. Statement of Issue *(Leave blank if no issue is identified. In addition to stating the issue, indicate the
Issue Category and supporting evidence for each issue. Number multiple issues, e.g., 1, 2, 3, etc. There must be a
one-to-one correlation between issues and issue categories. No issue should be related to more than one issue
category. No issue category should be related to more than one issue.)*
PG&E RMP-06 requires company wide e-mails, from VP of Gas Transmission and Distribution, to be distributed informing transmission staff about IM activities; however, in
2008 (PG&E exception report generated) and in 2009 (no PG&E exception report generated) no company wide e-mail was sent to staff. USRB advised that PG&E RMP-06, Section 14.6 be more detailed to add other activities that currently were stated by PG&E staff as being performed, but don't appear to be captured under PG&E RMP-06, Section 14.6 (i.e., program metrics provided to senior management).

[50] ID at 148
[51] ID at 149

DECLARATION OF

Robert Sarvey, MBA, BS

I Robert Sarvey declare as follows

1) I prepared Exhibit 408: Pipeline Testimony of Robert Sarvey.

2) It is my professional opinion that the prepared testimony is valid and accurate with respect to the issues addressed therein.
3) I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.
4) A copy of my professional qualifications is attached.

I declare under penalty of perjury, under the laws of the State of California, that the forgoing is true and correct to the best of my knowledge and belief, and that this declaration was executed on March 18, 2011 in Tracy, California.

Robert Sarvey

Resume of Robert Sarvey

Academic Background

BA Business Administration California State University Hayward 1975

MBA California State University Hayward 1985

Experience

San Joaquin Valley Air Pollution Control District Citizens Advisory Board Industry Representative: Analyzed proposed air quality regulations and made recommendations to the Governing Board for approval.

GWF Peaker Plant 01-AFC-16: Participated as an Intervenor in the project and helped negotiate and implement a 1.3 million dollar community benefits program. Successfully negotiated for the use of local emission reduction credits with GWF to offset local air quality impacts.

East Altamont Energy Center 01-AFC-14: Participated as an Intervenor and helped develop the conditions of certification for hazardous materials transportation, air quality, and worker safety and fire protection. Provided testimony for emergency response and air quality issues.

Tesla Power Project 01- AFC-04: Participated as an Intervenor and provided air quality testimony on local land use and air quality impacts. Participated in the development of the air quality mitigation for the project. Provided testimony and briefing which resulted in denial of the PG&E's construction extension request.

Modesto Irrigation District 03-SPEE-01: Participated as Intervenor and helped negotiate a $300,000 air quality mitigation agreement between MID and the City of Ripon.

Los Esteros: 03-AFC-2 Participated as an Intervenor and also participated in air quality permitting with the BAAQMD. Responsible for lowering the projects permit limit for PM-10 emissions by 20%.

SFERP 4-AFC-01: Participated as an Intervenor and also participated in the FDOC evaluation. My comments to the BAAQM D resulted in the projects PM -10 emission rate to be reduced from 3.0 pounds per hour to 2.5 pounds per hour by the District. Provided testimony on the air quality impacts of the project.

Long Beach Project: Provided the air quality analysis which was the basis for a settlement agreement reducing the projects NOx emissions from 3.5ppm to 2.5ppm.

ATC Explosive Testing at Site 300: Filed challenge to Authority to Construct for a permit to increase explosive testing at Site 300 a DOE facility above Tracy. The permit was to allow the DOE to increase outdoor explosions at the site from 100 pounds per charge to 300 pounds per charge and also grant an increased annual limit on explosions from 1,000 pounds of explosive to 8,000 pounds of explosives per year.   Succeeded in getting the ATC revoked.

CPUC Proceeding C. 07-03-006: Negotiated a settlement with PG&E to voluntarily revoke Resolution SU-58 which was the first pipeline safety waiver of GO 112-E granted in the State of California. Provided risk assessment information that was critical in the adoption of the Settlement Agreement with PG&E which, amongst other issues, resulted in PG&E agreeing to withdraw its waiver application and agreeing to replace the 36-inch pipeline under the sports park parcel after construction.

East shore Energy Center: 06-AFC-06 Intervened and provided air quality testimony and evidence of cancellation of Eastshore's power purchase agreement with PG&E.

Colusa Generating Station: 06-AFC-9 Participated as air quality consultant for Emerald Farms. Filed challenge to the PSD Permit.

CPUC proceeding 08-07-018: Tesla Generating Station CPCN participated in proceeding which was dismissed due to motion by IEP. Reviewed all filings, filed protest, signed confidentiality agreement and reviewed all confidential testimony.

GWF Tracy Combined Cycle 08-AFC-07: Participated in negotiation of the Air Quality Mitigation Agreement with the San Joaquin Valley Air Pollution Control District and GWF.

CPUC Proceeding 09-09-021:   Provided Testimony on behalf of CAlifornians for Renewable Energy. Demonstrated PG&E failed to follow its environmental protocol in the LTPP. Provided testimony and evidence that PG&E's need had fallen since 2007 and that the Commission should limit PG&E's procurement to the 950-1000 MW Range.

CPUC Proceeding A. 09-04-001: Represented CAlifornians for Renewable Energy in the proceeding.

CPUC Proceeding A. 09-10-022: Provided Testimony on behalf of CAlifornians for Renewable Energy. Provided confidential evaluation of PPA value. Provided testimony and evidence that PG&E had violated the Mariposa Settlement. Provided testimony that demonstrated PG&E's demand had fallen sharply since the issuance of D. 07-12-052.