Docket:	:	R.11-02-019
Exhibit Number	:	__________
Commissioner	:	M Florio
Admin. Law Judge	:	MBushey
SED Project Mgr.	:	Darryl Gruen
	:	

SAFETY & ENFOREMENT DIVISION CALIFORNIA PUBLIC UTILITIES COMMISSION

REPORT AND TESTIMONY OF MARGARET FELTS

R.11-02-019

San Francisco, California
November 18, 2013

I. Introduction

My name is Margaret C. Felts. My Company name is M.C. Felts Company and my business address is 8822 Shiner Ct., Elk Grove, CA 95624. I am a technical consultant specializing in energy and environmental issues.

I have been the lead technical consultant on cases involving pipeline integrity and facility management records and processes, including the PG&E San Bruno pipeline explosion investigation, the Pacific Offshore Pipeline Company gas plant startup failure involving a high pressure release of gas containing toxic levels of hydrogen sulfide, and the Mohave coal slurry plant failure and explosion of a high pressure steam pipe.

At various stages during my career, I have been responsible for engineering and management of gas, oil, water supply, and waste water pipelines. Projects range from engineering design to leak detection, in line inspections, and pipeline removals.

A copy of my Curriculum Vitae is attached hereto.

I am sponsoring this testimony on behalf of the Safety and Enforcement Division of the California Public Utilities Commission. In accordance with the ALJ's ruling at the October 21, 2013 prehearing conference, this testimony focuses on evidence and circumstances related to PG&E's Line 147. (Prehearing Conference Transcript, p.78, l. 1-13 and p. 85, l.17-20) As noted below in the discussion of individual Line 147 safety concerns, these issues also can and should be applied to PG&E's broader gas transmission system. SED will submit additional testimony analyzing the broader OSC issues in those subsequent proceedings.

II. The Maximum Allowable Operating Pressure For Line 147

The Report of Sunil Shori contains the recommendation of the Safety and Enforcement Division regarding the permissible Maximum Allowable Operating Pressure for Line 147.

III. PG&E did not find the actual leak and, therefore, cannot identify its Root Cause, leaving open the question of the integrity of remaining A.O. Smith pipe in Line 147.

In October 2012, PG&E field workers detected a gas leak on Line 147. PG&E welded a 6 inch diameter cap over the area believed to be the site of the leak and later removed a 9 ft piece of pipe that included the 6”cap for laboratory testing. In spite of examination by two contract labs, and PG&E’s own ATS lab, PG&E could not locate the site of the leak, and still cannot today. As a result of the leak investigation, however, it was discovered that the pipe was 1929 A.O. Smith pipe, which had been installed at the site in 1947, after previous use in another location. In fact, A.O. Smith pipe runs for ¼ mile (1,395 ft.) in Line 147.

PG&E has not clearly acknowledged that the exact site of the leak remains undetected. PG&E continues to suggest, by referring to laboratory results, that there is a valid root cause analysis. In fact, the laboratory reports do not identify the site of a leak and thus, by definition, their reports cannot identify a root cause of that leak. PG&E attempts to focus attention on the unanswerable question of what caused the leak, while failing to openly acknowledge that the leak was never located. Thus, PG&E invites debate on a question that cannot have a meaningful answer.

Because PG&E was not able to locate or, therefore, to analyze the site of the October 2012 leak, that incident cannot provide specific useful guidance about vulnerabilities that may exist on these 1,395 ft. of A.O. Smith pipe in Line 147. Equally important, that incident and the subsequent failed efforts to analyze it cannot provide any reassurance about the integrity of the remaining A.O. Smith pipe installed elsewhere in the system.

Evidence related to these issues is addressed below.

On October 13, 2012, a leak was discovered on Line 147.

> "On the same day, a leak surveyor investigated the potential leak, but was unable to obtain a useable reading with his gas detection device due to the accumulation of water and mud from the nearby water main break. The leak surveyor returned to the site on the morning of October 15, 2012, and was able to confirm the leak."[1]

The leak surveyor then remained on site until arrival of the construction crew, as discussed in paragraph 26 of PG&E's Verified Statement.[2] PG&E's construction crew drilled holes, measured the gas concentrations and changed the leak from a grade 1 (immediate response) to grade 2+ (respond within 90 days).[3]

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[1] Verified Statement of Pacific Gas and Electric Company's Vice President of Gas Transmission Maintenance and Construction in Response to Ruling of Assigned Commissioner and Assigned Administrative Law Judge, August 30, 2013, para. 25

[2] Ibid, para. 26

[3] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch538 (A-Form)

On October 18, 2012, a PG&E crew exposed the Line 147 pipe in the area of the leak. In his Verified Statement, PG&E's Vice President, Kirk Johnson, states that the pipeline engineer on site visually investigated and realized the long seam weld of the exposed section of pipe appeared to be A.O. Smith variety.[4] Mr. Johnson does not say when, how or by whom the location of the leak was determined.[5]

On November 13, 2012, PG&E repaired what it thought was the source of the leak by welding a 6" cap over the assumed site, then covered the pipe without doing the x-rays and other analytical inspections that PG&E engineers had requested.[6]

Nine months later, on August 9, 2013, PG&E excavated the leak site and removed a portion of the line where the cap was welded to the pipe and sent the piece of pipe to the Anamet, Inc. laboratory for a Root Cause analysis.[7] Anamet, Inc. could not find the leak and, in a report to PG&E, stated:

> "Please take a look at the attached photos. After cleaning, I put developer on the inside of the section and penetrant on the outside within the sectioned PLiDCO cap. No leak path was detected. There is a crack like feature on the inside surface. Do you want me to roll the dice and do some sectioning, or would you like to have your guys do RT[8] first?"[9]

The Anamet, Inc. Report findings include:

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[4] Verified Statement of Pacific Gas and Electric Company's Vice President of Gas Transmission Maintenance and Construction in Response to Ruling of Assigned Commissioner and Assigned Administrative Law Judge, August 30, 2013

[5] GasPipelineSafetyOIR_DR_SED_007-Q08: In response to the question, how did PG&E identify the location of the leak, PG&E responds "PG&E field personnel detected the leak location using a leak survey tool called a Combustible Gas Indicator."

[6] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch467, and GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch489

[7] A root cause analysis is an investigation where the cause of or reason for a particular anomaly or condition is determined. In this context, the root cause analysis would determine as precisely as possible the metallurgical conditions present that created the identified leak. -- Declaration of Sumeet Singh, September 13, 2013, para. 4, Supporting the Verified Statement of PG&E V.P. of Gas Transmission Maintenance and Construction in Response to Ruling of Assigned Commissioner and Assigned Administrative law Judge, August 30, 2013, para. 51; also GasPipelineSafetyOIR_DR_DRA_086-Q02Atch01

[8] RT means Radiographic Testing

[9] _GasPipelineSafetyOIR_DR_DRA_086-Q22Atch068 (email from Assoc. Director of Laboratories to PG&E Engineer (GT&D); GasPipelineSafetyOIR_DR_DRA_086-Q22Atch157 (23 Sept – 2nd version; <u>note:</u> 1st version was provided as 1 to the Verified Statement, September 6, 2013)

> "As shown in Figure 10 through Figure 20, a weld crater crack extended from the outside surface into the weld heat affected zone in section 1a, but did not penetrate through-wall at this location."[10]

> "In section 1b, shown in Figure 13 through Figure 15, cracks were present from the outside surface to the inside surface. Only a few ligaments prevented the demonstration of a through-wall leak path."[11]

> "In section 1c, shown in Figure 16 through Figure 18, one small ligament at the outside surface prevented demonstration of a through-wall leak path."[12]

In its apparent frustration at not being able to find the leak, PG&E devised a pressure test, which was performed on the sample pipe by Anamet, Inc. in the laboratory.[13]

> "A pressure test was performed by clamping a plate over the sectioned cap, sealed with a silicone gasket, and introducing 40-psig of compressed air. Snoop® liquid leak detector was applied to the inside surface. No leaks were detected. The compressed air was valved-off, and no pressure drop from 40 psig was detected after 45 minutes.[14]

Because it could not find the leak, Anamet, Inc did not perform a Root Cause Analysis. Instead, Anamet provided a qualified conclusion:

> "Metallography revealed a leak path was <u>likely</u> present under the PLIDCO cap between an external weld crater crack and liquation cracks in the underlying weld heat affected base metal."[15] (Underline added)

PG&E sent the pipe to its own lab, ATS for further analysis. PG&E's Principal Corrosion Engineer wrote:

> "Pls arrange for someone to shoot this part to locate the leak. You can do at Anamet or bring back to ATS and do it? Then run it back to Anamet. Which would you prefer? As usual we need it quickly. <u>Work at Anamet stops until we locate the leak</u>."[16] (Underline added.)

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[10] GasPipelineSafety OIR_DR_SED_005-08Atch02, Anamet, inc. Report No. 5004.9268, Sec. 2.2 Metallography, p. 3 (includes high resolution color photos)
[11] Ibid.
[12] Ibid.
[13] GasPipelineSafetyOIR_DR_DRA_086-Q22Atch078
[14] GasPipelineSafety OIR_DR_SED_005-08Atch02, Anamet, inc. Report No. 5004.9268, Sec. 2.1 Visual Examination, p. 2
[15] Ibid, Sec. 3.0 Conclusions, p.4
[16] GasPipelineSafetyOIR_DR_DRA_086-Q22Atch078, p. 2. *Note:* "Shoot" is reference to some unspecified inspection technique, such as x-ray.

In late September 2013, PG&E sent the same pipe section to Exponent, Inc. to conduct an independent review of the Anamet report and to perform additional analysis.[17] Exponent confirmed the Anamet analysis,[18] and was also unable to find the leak. The Exponent, Inc. report includes the following:[19]

> "As shown in Figure 5, the pre-existing crack in Sample A-1-1-8 only extended from the OD approximately halfway through the pipe wall. The pre-existing crack A-1-1-7 extended from the ID nearly to the OD surface. <u>While neither of these two samples display a clear ID-to-OD leak path</u>, the pre-existing crack in Sample A-1-1-7 extends nearly through the pipe wall thickness."[20] (Underline added.)

The above finding is inconsistent with the conclusions listed at the end of the Exponent Report, which state that there was a leak.[21]

Thus, after what appears to have been a thorough examination of a 6 inch diameter circular area on the Line 147 pipe body, PG&E has not been able to prove that this piece of pipe was in fact the source of the leak that was detected in October 2012. Nevertheless, when asked about the root cause of the leak, PG&E said:

> "The original root cause of the leak was identified under difficult field conditions as external corrosion - this is what was on the A-form. It was not the result of a laboratory examination or a test. After cut out and lab analysis the cause was determined to be "Material Failure" due to the weld metal cracking in the base metal."[22]

When PG&E was asked what evidence it can point to in the Anamet Report that confirms the leak detected was in fact in the area beneath the PLIDCO cap had been welded to the pipe, PG&E responded:

> "The entire report speaks to that issue. Specifically figures 16, 17, and Appendix A, identify <u>nearly</u> 100% through wall cracking." (Underlining added.)

[17] GasPipelineSafetyOIR_DR_DRA_086-Q22Atch149
[18] GasPipelineSafetyOIR_DR_DRA_087_Q48; GasPipelineSafetyOIR_DR_DRA_086-Q22Atch189; GasPipelineSafetyOIR_DR_DRA_086-Q22Atch145
[19] GasPipelineSafetyOIR_DR_DRA_086-Q22Atch070, GasPipelineSafetyOIR_DR_DRA_086-Q22Atch191
[20] GasPipelineSafetyOIR_DR_DRA_086-Q22Atch191, p. 7
[21] GasPipelineSafetyOIR_DR_DRA_086-Q22Atch191, p. 22
[22] GasPipelineSafetyOIR_DR_DRA_086-Q39 e.

Of course, any crack that did not go 100% through the pipe wall could not have been the site of the leak.

PG&E also searched its records to find evidence of a prior leak that had been repaired at the location it thought to be the source of the leak, which would explain the purpose of the weld material found on the 1929 pipe. No such records were found.[23]

Recently, DRA asked PG&E: what was the most probable cause of the leak according to PG&E engineers reviewing this leak and the Anamet report? PG&E responded:

> "PG&E concurs with the probable cause conclusion in the Kiefner & Associates "Current fitness for service of Line 147" letter, provided as Appendix G to the October 18, 2013 Statement of Sumeet Singh (R.11-02-019)."[24]

However, a word search of the Keifner letter quoted above, written by Mr. Rosenfeld, reveals no occurrences of the phrase "probable cause."[25] The word "cause," appears, but in a context completely unrelated to PG&E's response. In fact, none of Mr. Rosenfeld's conclusions discuss the cause of the leak.[26]

Finally, PG&E had an opportunity, when the Line 147 pipe trench was open in October and November of 2012, to investigate the condition of the longitudinal and circumferential welds in the area where the leak had been detected. But, despite the Consulting Engineer's requests to inspect the welds, PG&E buried the line without performing the requested radiographs.[27]

To determine the root cause of a leak, PG&E must first identify the location and type of leak. A leak is a through-wall crack or hole in the pipe. The importance of identifying the exact source of the leak in the pipe or pipe weld and then performing a root cause analysis of that leak is to determine if similar pipe, subjected to the same operating conditions, also could contain unstable cracks that might present a safety risk. Based on the data provided by PG&E, including the test reports by Anamet and Exponent, PG&E never found the exact location of the Line 147 leak that field personnel detected using gas detection equipment in October 2012. Therefore,

[23] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch528

[24] GasPipelineSafetyOIR_DR_DRA_087-Q46

[25] At some point in discovery, the phrase "probable cause" appears to have replaced "root cause." A word search of the Keifner Letter for "root cause" also returned no occurrences of the phrase.

[26] Kiefner & Associates "Current fitness for service of Line 147" letter, provided as Appendix G to the October 18, 2013 Statement of Sumeet Singh (R.11-02-019), p. 1

[27] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch467

PG&E was unable to perform a Root Cause Analysis and does not know if there are unstable cracks in other parts of Line 147 that could fail under stress.[28]

Recommendation: PG&E should replace the AO Smith and SSAW pipe identified in Line 147.

IV. L-147 MAOP calculations must take into account risks posed by the system-wide disarray of PG&E's pipeline records.

In D. 11-06-017 (p. 8), the Commission quoted a PG&E Vice President who stated that, prior to doing a hydrostatic test, it is important to know the components of the pipeline to be tested:

> "What you want to know is everything that's in the ground before you start conducting that test so that you don't put yourself in a situation where you've led to unintended consequences by pressuring that pipe up."

The Vice President went on to explain that, with regard to seamed pipeline, where adequate records are not available regarding the strength of the longitudinal weld, PG&E would dig up the pipe and verify the condition of the weld. PG&E offered its validation for Line 101 as an example of how it intended to approach issues of missing records. [29] [30] Had PG&E pursued this strategy, it would have found the A.O. Smith pipe in Line 147 prior to hydrotesting the line in 2011 and would have run the hydrotest to a safer, lower peak pressure. Accurate records are needed to calculate MAOP and also to safely conduct pressure tests, as PG&E's vice-president testified.[31] In the absence of these records, truly conservative assumptions must be made.

The surprise discovery of reused pipe in Line 147 during a leak investigation highlights the continued safety risks to PG&E's employees and the public posed by the continuing disarray in PG&E's pipeline records. Three of the highest priorities are discussed below.

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[28] Applies generally to other 1929 A.O. Smith pipe in the transmission system (247 miles, see Section IV.A below).

[29] D.11-06-017 at 8 – 9, Response to DRA DR 86 Q 32

[30] D.11-06-017, p. 94-95

[31] D.11-06-017, p. 95

SB_GT&S_0294495

A. Risk 1 – PG&E's failure to apply appropriate conservative assumptions for all "unknown" features poses a serious risk.

In PG&E's Pipeline Features List (PFL) "Build" database the word "unknown" is pervasive in entries relating to vintage pipe installed before 1970.[32] The inability to identify the type of pipe in the ground seems to be the most critical problem for PG&E. Each pipe with "unknown" characteristics (features) represents a potential site for PG&E to discover inferior pipe, like the one recently found on Line 147. This lack of information prevents PG&E from accurately determining pipeline MAOPs that are safe and that will support the service level necessary for PG&E to provide service to its customers. Maximum hydrotest pressures are selected based on the design MAOP, which is calculated using pipe characteristics (data). Thus, it is important to deal with the problem of "unknown" data as soon as possible.

In this proceeding, PG&E produced a contract showing that it had purchased A.O. Smith pipe in 1929,[33] and seems to represent this contract as the source of the pipe found in Line 147. The contract shows PG&E received 247 miles of pipe. Most of that pipe is probably still in the PG&E transmission system somewhere. In addition to this A.O. Smith pipe, there are hundreds of miles of other vintage pipe in PG&E's transmission system, some of which has been moved from one location to another.

PG&E purports to recognize the significance and importance of using the most conservative assumptions when actual data is unknown and is accumulating records of reused pipe in a database that has grown to almost 300 rows of data. [34]

> "PG&E does not in all instances know where reconditioned pipe has been placed in its transmission system. In the building of its Pipeline Features List (PFL), PG&E has been gathering this information where it is available."[35][1]

[32] PG&E's Supporting Information for Safety Certification of Lines 147 Pursuant to Ruling of Assigned Commissioner and Assigned Administrative Law Judge, Exhibit B, October 16, 2013

[33] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch408

[34] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475, p. 4-5

[35] I.11-02-016, Pacific gas and Electric Company's Response to the Consumer Protection and Safety Division's Reports: Records Management Within the Gas transmission Division of PG&E Prior to the Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010 and Report and Testimony of Margaret Felts Testimony of Witnesses, p. 3-32.

However, there is no assurance that errors like the one that occurred on Line 147 have not occurred throughout PG&E's PFL process, especially for High Consequence Area (HCA) lines, which were the first lines to be documented using the early PFL procedures. It is important that PG&E correct the errors. However, the Commission may want to prioritize certain projects based on experience with Lines 132 and 147.

To identify the highest priority for action, consider the similarities between the San Bruno Line 132, Segment 180 project and the San Carlos Line 147, Segment 109 project. Both projects were in-house construction (not installed by a contractor), built in the 1956-1957 period and were constructed of salvaged materials of unknown origin and operational history. The pipe was characterized as seamless in the GIS and IM databases.[36] PG&E cannot find the original project file for either of these installation projects.[37] Any pipelines sharing all or some of these characteristics should be given special consideration.

B. Risk 2 – PG&E's data errors result in incorrect MAOP calculations for Line 147.

The NTSB noted the importance of records for calculating MAOP in its instructions to PG&E:

> " . . . It is possible that there are other discrepancies between installed pipe and as-built drawings in PG&E's gas transmission system. It is critical to know all the characteristics of a pipeline in order to establish a valid MAOP below which the pipeline can be safely operated. The NTSB is concerned that these inaccurate records may lead to incorrect MAOPs."[38]

Accurate data or the most conservative assumptions are required to calculate a valid MAOP.[39] However, in cases where pipeline data was unknown, PG&E's PFL system may not have produced the most conservative assumptions.[40]

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[36] P3-20060 from PG&E rolling production

[37] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475

[38] NTSB Safety Recommendation P-10—2, -3 (Urgent) and P-10-4, January 3, 2011, at 2

[39] 49 CFR 192.505

[40] This section focuses on PG&E's PFL system. A broader concern is that PG&E is using multiple databases that should contain the same set of data for its pipelines. Instead, it appears that the multiple databases contain different data (and assumptions) for similar pieces of pipe. Some of the data bases PG&E refers to are: PFL, GIS 2.0, GIS 3.0, Intrepid, Integrity Management and eGIS. Further, it appears that the corrections to GIS 2.0 that originated from field personnel and engineers (as reflected in the Change Log that PG&E provided in the Recordkeeping OII) may not be migrated to other data bases.

PG&E created a procedure to help engineers fill in assumptions for pipe with unknown PFL data. The procedure, as produced by PG&E is in draft form, although the process of filling in features list assumptions for HCA pipe was concluded at the end of 2011. The draft, dated October 9, 2013, is titled "Procedure for the Resolution of Unknown Pipeline Features" (PRUPF).[41] PG&E states that it uses Gas Standard and Specification A-11 (SP A-11) to assign joint efficiency factors for various pipeline seam types, including single submerged arc welded pipe.[42] SP A-11 is titled "Identification of Steel Pipe" and provides information about features of different types and vintages of pipe. It is incorporated into the PRUPF.[43]

In some instances, a flaw in PG&E's PRUPF prevents PG&E from accurately assigning assumptions to unknown pipe when the pipe is reused. The PRUPF process of assigning assumptions is based on knowing, or accurately estimating, the purchase date of the pipe. The "look-up" tables provided in PG&E's PRUPF procedure provide values to assign as assumptions in the Pipeline Features List in place of data that is unknown. The flaw occurs because these tables are keyed to the purchase date of the pipe. PG&E reasoned that no pipe would have been kept in storage yards for more than 10 years. Therefore, the most conservative assumed purchase date would be 10 years earlier than the "install date."[44] Thus, for a pipe installed in 1957, the assumed purchase date would be 1947.[45]

The problem created by the 10-year storage assumption, when the unknown pipe happens to be reused pipe, is illustrated by the case of Line 147, segment 109, which was installed in 1957. Based on the 10–year-storage assumption, PG&E engineers assumed the pipe had been purchased in 1947, when in fact it had been purchased in 1929. Because PG&E did not purchase A.O. Smith pipe in the late 1940s, PG&E'S 10-year-storage assumption excluded the possibility that the unknown pipe installed in 1957 could be 1929 A.O. Smith pipe.[46]

In the case of Line-147, the 10-year-storage assumption suggested the pipe would have been purchased in 1947, thus it might have been SSAW pipe. PG&E has explained that SSAW

[41] GasPipelineSafetyOIR_DR_SED_002-001 Atch 02. The copy provided to SED is not dated and is Version 0. The same document, also Version 0, dated October 9, 2013, was submitted to the Commission on October 29,2013 within the document titled "PG&E Pipeline Safety Enhancement Plan (PSEP) Update Prepared Testimony," Application 13-10(U 39 G), filename: PSEP_Update_Test_PGE_20131029_289314 (from PG&E web site)

[42] GasPipelineSafetyOIR_DR_SED_002-001 and pelineSafetyOIR_DR_SED_002-001 atch 01

[43] GasPipelineSafetyOIR_DR_SED_002-001

[44] GasPipelineSafetyOIR_DR_SED_002-001Atch02, p. 9, Section 3.3

[45] Ibid, p. 18, Table 2, where determination of unknown long seam type is based on purchase date,

[46] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch466

pipe has the same joint efficiency (.8) as A.O. Smith pipe. Thus, the incorrect assumption of a 1947 purchase date would nevertheless result in the correct joint efficiency number in this instance.[47] PG&E attributes the erroneous assumption of DSAW and a resulting Joint efficiency of 1.0 to an incorrect decision made by a PG&E engineer.[48] So, it happens that in this instance, if the PG&E instruction had been followed, the pipe type would have been misidentified, but the critical data, i.e. the joint efficiency factor, would have been correct.

While PG&E represents that it is fixing this problem in the PRUPF process by automating it, it cannot deny that the entire PFL database was populated with assumptions prior to discovering this problem.[49]

Recommendation: For Line 147, PG&E must revisit each assumption made before it discovered the PRUPF problem, in order to determine if it should be modified to a more conservative value. The same task lies ahead for PG&E on the broader scale for all pipelines in high consequence areas.

C. Risk 3 – A pressure test alone is not an adequate basis for an MAOP.

PG&E argues that even though the data for Line 147 does not support the MAOP of 365 psig, which is the MAOP the Commission restored the line to in 2011, operation of the pipe to that pressure was safe because the pipe had withstood a pressure test that supports an MAOP of 365 psig.[50] However, it is more likely that PG&E was simply lucky that the pipe did not fail before the weakest links of A.O. Smith and SSAW pipe were discovered and the MAOP was reduced to 330 psig. As it turned out, by running a pressure test before it knew of the A.O. Smith pipe, PG&E exceeded the SMYS of the pipe, potentially damaging the pipe and activating previously stable cracks, creating an ongoing safety risk.

According to PG&E, in November 2012, just after the leak on Line 147 was discovered, "[t]he PSEP team was asked to re-evaluate this line using their logic tree to see if this pipe would be replaced or prioritized differently." Specifically, in emails between PG&E managers,

> ". . . this segment would not need to be replaced in phase 1, work to be done by 2014. According to the PSEP Decision Tree, this segment would

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[47] ibid

[48] Verified Statement of Kirk Johnson, August 30, 2013, para.35

[49] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475

[50] Verified Statement of Kirk Johnson, August 30, 2013 para 5, para 22, and Verified Statement of Sumeet Singh, Oct 18, 2013, para 12.2, quoting Keifner & Associates

> have an action of "Retrofit and conduct an ILI at next re-assessment" (C7). This is because the pipe already has a valid strength test record, is HCA and is operating over 30% of SMYS. Unless adjacent segments need to be replaced or tested, then this segment would not be addressed as part of PSEP."[51]

Despite the implied suggestion in PG&E's statement that any pressure test can be used to support a desired MAOP, such a position is contrary to PG&E's own standards and explanations of the risks of over pressuring a line.

PG&E's standard for piping design and test requirements is A-34. The most recent version of A-34 is Revision 4, dated March 29, 2013.[52] The instructions for performing a pressure test for MAOP include the following statements:

> "(3) **Maximum Test Pressure at Minimum Elevation**
> Determine this value by referring to the **Maximum Test Pressure** row of Table A-1 in Numbered Document A-34, Attachment A, "Test Requirements." Read all associated notes and, if necessary, adjust to create a practical test range. Ensure that the pressure range is sufficient to permit variations in the test pressure due to elevation, temperature changes during the test, or equipment problems/limitations.
>
> "Where an elevation difference exists, the maximum test pressure occurs at the lowest elevation point in the test section. The **control point** is most often at the minimum elevation. If there are sections of pipe with different specifications or strengths or other limiting components, then the control point might be at a higher elevation. Explain this exception in the **Components limiting test pressure/Control Point exceptions** field in Part 1 of the STPR.
>
> "<u>CAUTION: The test pressure for any pipeline must not be greater than the pressure which produces a hoop stress of 100% of SMYS of the pipe, regardless of the strength of the valves, regulators, and similar equipment.</u> If the MAOP of the pipeline cannot be established without exceeding the rated pressure of the equipment, consult Pipeline Engineering."[53] (Underline added.)

[51] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475_CONF, Sec. 3.0. *Note*: ILI means In Line Inspection.
[52] GasPipelineSafetyOIR_DR_DRA_087-Q02Atch01, Note: It does not appear that the sections quoted were changed in any significant ways from the previous versions of A-34.
[53] Ibid, P. 34

In a data response, PG&E elaborated on the risks of exceeding the SMYS of a pipe during a pressure test:

> a. If the test pressure causes the hoop stress on the pipe to exceed 100% of the specified minimum yield strength (SMYS) of the steel, then the steel can weaken and experience structural damage. If the test pressure exceeds the mill test pressure, small, otherwise stable manufacturing defects in the pipe could cause the pipe to fail. . .
>
> b. It is preferable to have accurate records whenever possible. However, industry experience demonstrates that operators will sometimes lack complete historical records for older pipe. In such instances, as the Commission has recognized, it is appropriate to use engineering-based conservative assumptions for pipeline components where complete records are not available.
>
> c. Hydrotesting a line without accurately calculating hoop stress could pose a safety risk if the pipe were to significantly yield during the test but not rupture, leaving a potential weak point in the pipe. PG&E's testing procedures have safeguards that minimize the safety risk in this situation. First, we make significant efforts to understand the pipe characteristics prior to testing. This includes conducting physical inspections of the pipe with unknown characteristics before testing if possible. Where there are still unknown characteristics, PG&E's test procedure for in-situ pipe monitors for pipe yielding by maintaining a Pressure versus Volume plot of each test. Pipe yielding would be the indication that the pipe was different than expected and the test pressure was too high for that segment of pipe (as explained in the response to part (a)). Pipe yielding is monitored by recording the pressure increase versus the pump strokes and corresponding volume of water added to the test section to produce the pressure during the pressure test. The theoretical slope within the elastic range for the pipeline is produced and the actual pressure and volume are plotted throughout the pressurization of the segment. If the pressure vs volume plot begins to deviate from the elastic slope, it is an indication that there is excessive air trapped within the test section being compressed, the elastic limit of some pipe within the section has been reached, or a leak has occurred.[54]

The relevant concern for Line 147 is that because PG&E was not aware of the older, reused pipe in the line, it tested the pipe to a pressure level that "probably" exceeded 100 % of

[54] GasPipelineSafetyOIR_DR_DRA_086-Q22

the pipe's SMYS. This was an unsafe pressure level based on PG&E's own guidance. [55] PG&E has stated:

> "Given the 0.8 joint efficiency of the AO Smith pipe and the hydro test pressure. The hydrostatic test probably <u>took the line 0 - 10 psi over the 100% SMYS level</u>." (Underline added)[56]

In fact, the 2011 pressure test (also referenced in Part II above) indicates pipe yielding in the Pressure v. Volume plot for the test T-43B (Mile Point 1.95 to3.40).[57] PG&E's certifying engineer, who does not appear to have been on site during the pressure test, discounted the test results by noting that excess air was introduced into the pipeline.[58] However, there is no real evidence other than the note on the certification statement that air was introduced into the pipeline.

PG&E clearly understands that a hydrotest at too high a pressure can cause a pipe to fail. PG&E's expert metallurgist, Robert Caligiuri, testified in the San Bruno case I.12-01-007 regarding the failure of L-132, that the root cause of the failure was a hydrotest performed when the pipe was installed and that, over time, a pre-existing defect that survived the pressure test ultimately failed catastrophically.[59] As PG&E stated in that proceeding:

> "Dr. Caligiuri also analyzed the possible source of the ductile tear, without which fatigue crack growth to rupture would not have been possible. Based on burst pressure and metallurgical stress analyses, as well as the absence of any other plausible cause, Dr. Caligiuri concluded the ductile tear in the longitudinal seam on pup 1 was likely caused by a post-installation pressure test.[60] Dr. Caligiuri's metallurgical examination revealed that the initiation of the ductile tear preceded the fatigue crack growth. Dr. Caligiuri further determined that the magnitude of the single loading event required to cause the ductile tear was greater than the operational pressure fluctuations Segment 180 likely experienced over its

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[55] See above, and GasPipelineSafetyOIR_DR_DRA_086-Q22Atch078
[56] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch499
[57] GasPipelineSafetyOIR_DR_DRA_086-Q02Atch04_CONF, p. 25-26
[58] GasPipelineSafetyOIR_DR_DRA_086-Q02Atch04_CONF, Note under "Remarks" on page 18 (Note, too, that the remarks also include a statement that the water truck ran out of water during the spike pressure test. Given that the engineers should accurately calculate how much water is required for a hydrotest, and given that loss of water is often associated with leakage, this finding suggests a test that might not have been well managed or overseen, calling the results into question.)
[59] I.12-01-007 PG&E Opening Brief, March 11, 2013, p. 14
[60] Ex. PG&E-1 at 3-5 to 3-17 (PG&E/Caligiuri)

> lifetime.[61] Using mathematical models to calculate the pipe's burst pressure, Dr. Caligiuri concluded that a post-installation hydro test was the likely cause of the ductile tear in pup 1."[62] [63]

PG&E's Consulting Engineer was obviously concerned that the 2011 hydrotest might have caused the leak in Line 147 when he wrote in an email:

> "[c]ould the recent hydro test [have] contributed to additional cracking in this pipe and essentially activated a threat? Are we sitting on a San Bruno situation? With fatigue crack growth over many years? Is the pipe cracked and near failure? I don't want to panic people but seems like we should consider this and probably move this pipe up the PSEP priority for replacement."[64]

In an internal report, the Consulting Engineer also stated:

> "[T]he appearance of a leak a year after this pipe was hydro tested, with external corrosion that was previously repaired, and knowledge that the pipe was originally manufactured in 1929 all indicate that we could have more extensive problems on this section of pipe. There is potential that the hydro test has "activated" cracks within a potentially weakened and older pipe."[65]

And,

> "[t]he change in pipe specifications requires a re-evaluation of the 2011 hydro test to determine if the pipe was over-stressed by the hydro test. The difference in elevation from the lowest elevation to the location of the AO Smith pipe is approximately 104 ft or approximate 45 psi. The maximum test pressure at the minimum elevation was 748 psi. The AO Smith pipe would have been subjected to a test pressure of 703 psi. Using what we currently believe to be the correct pipe properties 100% SMYS occurs at 700 psi."[66]

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[61] Ex. PG&E-1 at 3-9 (PG&E/Caligiuri). As Dr. Caligiuri further explained: "Fatigue cracking is characterized by stable crack growth that occurs incrementally over time in response to cyclic loading. Characteristic features called fatigue striations, indicative of fatigue growth under operational pressure fluctuations, were present at greater depths than the ductile tear." *Id*

[62] Ex. PG&E-1 at 3-11 to 3-12 (PG&E/Caligiuri).

[63] I.12-01-007 PG&E Opening Brief, March 11, 2013, p. 15

[64] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch443

[65] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475

[66] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475, Sec 3.3.7

Further, PG&E's experts, Keifner & Associates, advise the industry that defects surviving pressure tests may ultimately result in pipeline failure from fatigue, stating

> "If a pipeline is hydrostatically tested to a given pressure, defects of a certain size that are present at the time of the test will fail. Smaller defects would be expected to survive the test but would not be expected to grow further at a static pressure level much below the test pressure level. However, if a defect as large as size 'a' remains after a hydrostatic test and if the pipeline is subjected to sufficient pressure fluctuations, the defect will fail after time 't.'"[67]

Keifner goes on to explain how the data from a test scenario was used to calculate 'time to failure' based on the number and frequency of pressure fluctuations.[68] The risk with Line147 is not associated only with current operations. It is also necessary to consider the past, largely unknown operating history of some of the older, vintage pipe in the pipeline, and also the possibility that PG&E might alter operations on this line in the future (increasing pressure and cyclic pressure frequency) long after this proceeding has concluded. Safe operation of Line 147, in its current configuration, requires operating the line at a low and relatively constant pressure.[69]

Recommendation: Accurate data or the most conservative assumptions must be applied in order to conduct hydrotesting safely. It is recommended that PG&E follow its own internal procedures and guidance on pressure testing, as shown in this section.

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[67] "When does a pipeline need revalidation? The influence of defect growth rates and inspection criteria on an operator's maintenance program," Keifner, John F., and Vieth, Patrick H., Keifner and Associates, Inc., published in Pipeline Rules of Thumb Handbook, E.W. McAllister, Editor, p. 690, 2009

[68] Ibid, p. 691-692

[69] GasPipelineSafetyOIR_DR_DRA_086-Q13aAtch475, Sections 1.2 , 2.2, 3.2

ATTACHMENT

Margaret Felts

Serves as the lead technical consultant to law firms, regulatory agencies and private entities on environmental, energy and corporate fraud cases, concentrating her practice on behind-the-scene discovery, research and strategy development. She also serves as Expert Witness.

Positions external to consulting include serving as Deputy Director of the California Department of Toxic Substances Control (DTSC), where she managed the State's Superfund program, including the base closure program for the oversight of toxic cleanup of military bases closed by the federal government. Prior to working for the state, Felts served as Division Chief of Environmental Engineering at for the Department of Defense at McClellan AFB. In this position she was responsible for developing a program to bring the base into compliance with Federal, State and local environmental regulations. Felts came to California from Texas when she was recruited by the California Energy Commission to fill a lead technical position in the Fuels Office.

SPECIALTIES

Discovery and technical strategies for complex cases Involving:

- Pipeline Integrity Management records and processes
- Gas and Electric Utilities regulatory cases
- Oil & Gas industry cases
- Groundwater contamination
- Hazardous waste disposal and site cleanup
- Historical records research

EMPLOYMENT HISTORY

LITIGATION CONSULTANT 1983 - PRESENT
M.C. Felts Co. (see attached page)

PRESIDENT / CFO 2002 - 2010
California Communications Association

SENIOR CONSULTANT 1995-1997
Dames & Moore

DEPUTY DIRECTOR 1993-1995
California Department of Toxic Substances Control

DIVISION CHIEF OF ENGINEERING 1985-1990
Department of Defense, McClellan Air Force Base

ENVIORNMENTAL CONTRACTOR
INVICTUS CORP

ENERGY SPECIALIST
CALIFORNIA ENERGY COMMISSION

PROCESS ENGINEER
CELANESE PLASTICS AND SPECIALTIES

PROCESS ENGINEER
AMOCO OIL COMPANY, Yorktown Refinery

EDUCATION

J.D. PACIFIC MCGEORGE SCHOOL OF LAW
M.S. ENERGY/ENVIRONMENTAL ENGINEERING, LASALLE UNIV.
B.S. PETROLEUM ENGINEERING, LOUISIANA TECH UNIV.
B.A. COMMUNICATIONS, ECKERD COLLEGE

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Margaret Felts

LITIGATION EXPERIENCE AS LEAD TECHNICAL CONSULTANT AND EXPERT

2013-Present
APPLICATION NO. 1608617, PROCEEDING ID NO. 1995 ATCO PIPELINES – URBAN PIPELINE REPLACEMENT PROJECT
2011-Present
ORDER INSTITUTING INVESTIGATION (OII) ON THE COMMISSION'S OWN MOTION INTO THE OPERATIONS AND PRACTICES OF PACIFIC GAS AND ELECTRIC COMPANY WITH RESPECT TO FACILITIES RECORDS FOR ITS NATURAL GAS TRANSMISSIONSYSTEM PIPELINES. CONSUMER PROTECTION & SAFETY DIVISION
2005-2007
LODI GROUND WATER CONTAMINATION CLIENT: LAW FIRMS REPRESENTING LLOYDS OF LONDON INSURANCE COMPANIES INSURANCE DEFENSE
2000-2002
CALIFORNIA ENERGY CRISES ENRON INVESTIGATION PG&E BANKRUPTCY CLIENT: CA PUBLIC UTILITIES COMMISSION ENERGY, PLAINTIFF
PLAYA DEL REY GAS STORAGE INTEGRITY, SOCALEDISON CLIENT: CA PUBLIC UTILITIES COMMISSION, DIVISION OF RATE PAYER ADVOCATES ENERGY, PLAINTIFF
2001-2002
BELMONT PROPERTIES CLIENT: ROPERS ENVIRONMENTAL, DEFENSE
THREE SISTERS RANCH CLIENTS: DUANE MORIS & TED HANIG LAW FIRMS ENVIRONMENTAL, DEFENSE
AEROJET & LOCKHEED CASES CLIENTS: MORRIS POLICH & PURLLY, BERKES, CRANE, ROBINSON & SEAL LLP INSURANCE DEFENSE
PG&E POWER OUTAGE, SAN FRANCISCO DIVISION OF RATE PAYER ADVOCATES ENERGY, PLAINTIFF
1998-2000
RAYTHEON GROUND WATER CONTAMINATION LAW FIRMS REPRESENTING LLOYDS OF LONDON INSURANCE COMPANIES INSURANCE DEFENSE
1998-1999
PG&E TREE TRIMMING CASE
MONTEBELLO GAS STORAGE (SOCALGAS) CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES ENERGY, PLAINTIFF
1997 -2002
SKINNER V. ARCO CLIENTS: TERRY LUMSDEN LAW FIRM KELLER ROHRBACK L.L.P., ENERGY/ENVIRONMENTAL, PLAINTIFF
1996-1997
SOCALGAS V. ASSOCIATED ELECTRIC GAS INSURANCE COS. CLIENT: HANCOCK, ROTHERT & BUNSHOFT, LA INSURANCE DEFENSE
1997 -1998
EXXON V. INA, SUPERFUND CLEANUP CLAIMS CLIENT: HANCOCK, ROTHERT & BUNSHOFT, SF INSURANCE DEFENSE
1996-2000
PROCTOR V. LOCKHEED SOIL AND GROUNDWATER CONTAMINATION CLIENTS: LAW FIRMS REPRESENTING LLOYDS OF LONDON INSURANCE COMPANIES, PLAINTIFF
1993
TOOLEY OIL V. SNIDER CLIENT: NAGLEY & MEREDITH, INC. ENVIRONMENTAL, PLAINTIFF
CLAYTON RD. ASSO INC. V. TEXACO REFINING & MARKETING INC. CLIENT: NED ROBINSON ENVIRONMENTAL, PLAINTIFF
WALSH V. DIABLO MARINE CLIENT: TURNER, HUGUET, BRANS & ADAMS ENVIRONMENTAL, PLAINTIFF
TASSAJARA NURSERY V. INSURANCE CO. CLIENT: NELSON, WARNLOF & VENCILL INSURANCE, DEFENSE
1992
WISE/WILLIAMS V. BECHTEL CLIENT: POTTER LAW OFFICES TORT CASE FOR INJURIES RESULTING FROM MOHAVE POWER PLANT INCIDENT ENERGY, PLAINTIFF
PACHECO PROPERTIES V. CHEVRON PIPELINE CLIENT: TURNER, HUGUET, BRANS & ADAMS ENVIRONMENTAL, PLAINTIFF
NEVADA POWER V. STATE OF NEVADA CLIENT: STATE OF NV ATTORNEY GENERAL OFFICE OF ADVOCATE CUSTOMERS OF THE PUBLIC UTILITIES COMMISSION ENERGY, PLAINTIFF
1991-1993
PG&E APPLICATION RE HELMS PUMPED STORAGE CLAIM CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES ENERGY, PLAINTIFF
1991
SALLE V. RUDD, ET AL CLIENT: KLAUSCHIE & SHANNON, INSURANCE DEFENSE
1990
AEROJET GENERAL CORP, ET AL V. ARGONAUT INSURANCE CO., ET AL CLIENT: HANCOCK, ROTHERT & BUNSHOFT, INSURANCE DEFENSE
1988 -1992
SCE APPLICATION RE MOHAVE COAL FIRED PLANT STEAM PIPE FAILURE CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES, ENERGY, PLAINTIFF
1987-1988
SOCALGAS APPLICATION -CONTRACT BUYOUT RE MONTEREY LAND PARK LANDFILL GAS (OPERATING INDUSTRIES) CLIENT: CA PUBLIC UTILITIES COMMISSION, DIV. OF RATEPAYER ADVOCATES, ENERGY / ENVIRONMENTAL, PLAINTIFF
1986
SOCALGAS V. FORD, BACON & DAVIS CLIENT: LAW FIRM REPRESENTING FORD, BACON & DAVIS, ENERGY, PLAINTIFF
1985
US OF A BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION RE PACIFIC OFFSHORE PIPELINE COMPANY, DOCKET NO. RP85-34-000 CLIENT: CA PUBLIC UTILITIES COMMISSION, ENERGY, PLAINTIFF
1983 -1985
SOCALGAS, APP NO. 84-09-022 RE PACIFIC OFFSHORE PIPELINE COMPANY (POPCO) GAS TREATMENT PLANT CLIENT: CPUC, DIV. OF RATEPAYER ADVOCATES, ENERGY, PLAINTIFF