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October 18, 2013

Mr. Sumeet Singh
Pacific Gas and Electric Company
6121 Bollinger Canyon Road
San Ramon, CA 94583

Re: Current fitness for service of Line 147

Dear Mr. Singh:

At the request of Pacific Gas & Electric (PG&E), I have reviewed documents and data concerning the design, construction, operation, and maintenance of Line 147 in order to determine whether the hydrostatic pressure test conducted in October 2011 still establishes the pipeline's fitness for service. The objectives of my review were to:

1. Determine whether PG&E has adequate records or data concerning the pipe materials, construction features, and current condition of the line to fully understand and manage the integrity threats that could affect the pipeline;
2. Determine the effectiveness of the October 2011 hydrostatic pressure tests (and for some short segments of Line 147, tests conducted in 1987 or 1990) for establishing the line's fitness for service at the time of the tests;
3. Determine whether the fitness for service of Line 147 has degraded in the 2 years since the most recent tests.

Conclusions

My conclusions are as follows:

1. PG&E has substantial knowledge of the type of pipe, construction features, and appurtenances present in Line 147. Data from metallurgical examination of a leak that occurred in 2012 suggests that the affected pipe was reconditioned first-generation A.O. Smith line pipe. Records indicate that such pipe was shipped to the site in 1957, although it is not listed in the PFL, confirming that the database is not perfect. However, this does not cause a great deal of concern because of Item 2 below.
2. The October 2011 hydrostatic pressure spike test confirmed the fitness for service of the pipeline for its MAOP without doubt. The concept of pressure testing to establish the ability of a pipeline to safely hold pressure at a lower pressure is an accepted practice that is logical and supported by industry experience and research. NTSB and PHMSA have recommended and required, respectively, hydrostatic pressure testing to

revalidate pipeline operating pressures. The test was performed to a sufficient margin to assure the integrity of the pipeline well into the future assuming routine maintenance practices such as cathodic protection monitoring and damage prevention programs continue to be implemented.

3. A review of data concerning specific pipeline integrity threats provides no evidence that the integrity or fitness for service of Line 147 has degraded in the 2 years since the October 2011 hydrostatic tests were conducted.

These conclusions represent my professional opinion based on fact, observation, and interpretation of specific information.[1] The bases for my conclusions are discussed below.

Task 1. Determine whether PG&E has adequate records or data concerning Line 147

For Task 1, I reviewed a large number of records concerning Line 147 including:

- PG&E's Pipe Features List (PFL) database summarizing each unique item installed in the line, with links to supporting documents
- Test records from hydrostatic pressure tests conducted in October 2011, and in conjunction with pipe replacements in 1987 and 1990
- Results from metallurgical examinations and tests of a leak discovered at MP 2.29 in October 2012
- Pipe to soil potential readings from five cathodic protection (CP) test points
- Pipe to soil potential readings from close interval surveys conducted in 2013
- Information from reports of direct examination of the pipeline
- Photographs, pipe alignment survey data, and geotechnical information concerning an exposure of the pipe due to erosion on a slope at MP 1.80
- Photographic records concerning structural encroachments near the right of way
- Data on line locates, dig-ins, and leak rates caused by excavation damage
- Historical operating pressure data and fracture mechanics analyses of the effects of pressure cycles on seam defects
- Structural analyses of exposed pipe spans

The purpose of my review of the records was to determine whether PG&E has sufficient information to:

a. Select an appropriate operating pressure and comply with regulations
b. Possess awareness of threats to the integrity of the pipeline
c. Perform appropriate maintenance and repair activities
d. Execute integrity management activities

The review of the PFL was not intended to be an exercise to check for records errors or omissions. The PFL of Line 147 alone identifies 391 uniquely identified and located elements or features in the line's 4-mile length each having a number of detailed descriptors. It is possible for some errors or omissions to exist that may not be identified by a quick review.

[1] The scope of use of the information presented herein is limited to the facts as presented and examined, as outlined within the body of this document. No additional representations are made as to matters not specifically addressed within this report. Any additional facts or circumstances in existence but not described or considered within this report may change the analysis, outcomes and representations made in this report.

The PFL entries are based on a compilation of as-built drawings, pipe procurement documents, pipeline construction records, pipe replacement project documents, field examinations, and design drawings. The PFL indicates that Line 147 consists of 24-inch and 20-inch diameter line pipe in various combinations of wall thickness, specified strength grade, seam type, and vintage. Other features are present in line such as elbows, reducers, spans, drips, and mitered bends. My review of the PFL found that the description of the majority of individual pipes and other components is based on documentary evidence of some type. In some instances, PG&E relies on an engineering evaluation procedure (referred to as the Process for Resolving Unknown Pipeline Features or PRUPF, which I critically reviewed for PG&E on a prior occasion) to make conservative but realistic assumptions where technical attributes of the pipe are not verified.

PG&E's knowledge about the materials in Line 147 is not perfect. A leak was reported on October 15, 2012 near the intersection of Redacted at MP 2.29. A Plidco cap was installed to contain the leak.[2] Information from independent metallurgical examinations of the pipe that leaked[3,4] leads me to conclude that the leak occurred in pipe that was first-generation A.O. Smith pipe that had been reconditioned. The original source of the pipe is recognizable from the characteristics of the longitudinal seam,[5] while the pipe can be concluded to have been reconditioned for two reasons. First, the type of seam in the specimen predates the construction of Line 147. Second, the leak occurred in a weld deposit characteristic of repairs made during the reconditioning process. That reconditioned pipe may exist in Line 147 is supported by PG&E records indicating such pipe had been shipped to the site in 1957, although the PFL does not indicate the footage or location. The use of reconditioned pipe was not uncommon in the pipeline industry in the 1940s and 1950s due to demand for pipe exceeding supplies. Reconditioning of line pipe typically involved examining the pipe, repairing corrosion pits or other minor damage by welding to restore metal thickness, cutting off damaged sections that are irreparable by weld deposition, recoating the pipe, and pressure testing it. While the practice of installing reconditioned pipe does not generally continue, reconditioned pipe is found in service elsewhere, and industry safety standards have since 1955 specifically provided for the reuse of line pipe subject to verification of its sound condition by examination and hydrostatic testing. The fact that the affected pipe was manufactured by A.O. Smith is of little concern. A.O. Smith was among the highest quality line pipe available during the decades in which it was produced.

The fact that PG&E may not know all facts about every piece of pipe or component in Line 147 does not cause me particular concern considering that the pipeline in its current condition was successfully pressure tested to a level that supports a maximum allowable operating pressure (MAOP) of 400 psig. The hydrostatic test confirmed the ability of the pipeline to safely operate at the MAOP for at least the near-term future. The basis for this opinion is discussed below. I also believe that the information available in the PFL and all other sources is sufficient for PG&E to understand the integrity threats that could affect Line 147. These are discussed subsequent to the pressure testing discussion below.

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[2] PG&E A-Form 58-12-60279-B, 11/13/12.

[3] Anamet, Inc., "Metallurgical Evaluation of a Section from L-147 MP 2.2 Redacted", Report No. 5004.9268 Rev. 2, September 23, 2013.

[4] James, B., "PG&E Line 147 Redacted Metallurgical Analysis", Exponent Draft Report, October 2013.

[5] Rosenfeld, M.J., "Joint Efficiency Factors for A.O. Smith Line Pipe", www.kiefner.com, December 2012.

Task 2. Determine the Effectiveness of the 2011 Hydrostatic Test

Hydrostatic pressure testing involves filling the pipeline with water and pressurizing the water to a high level above the intended operating pressure of the pipeline. Hydrotesting is used to (1) qualify the operating pressure of the pipeline, and (2) assure the integrity of the pipeline for some period of time going forward. The effectiveness of hydrostatic pressure testing is based on the concept that if the pipe can successfully hold pressure at a high level, it is logical that it can safely hold pressure at a lower level. This principle has been demonstrated in hundreds of thousands of miles of pipelines since the 1950s.[6,7] The concept of pressure testing as a proof of the integrity of the pipeline, whether for new construction or integrity management of an existing facility, is embodied in every major pipeline safety standard and regulation in the US and internationally.[8,9,10,11,12] The effectiveness of the test is a function of the ratio of test pressure to operating pressure owing to an inverse relationship between defect size and failure stress. The higher the test pressure, the smaller are any flaws or defects that could have withstood the test. Thus a successful pressure test proves the absence of gross defects of a size that could affect the strength of the pipe at the operating pressure.[13] Larger test ratios translate to longer time to failure or more time to detect a problem in the event that any surviving flaws can enlarge while in service.

Test pressure requirements for natural gas pipelines are 1.25 times the MAOP in Class 1 and 2 areas, and 1.50 times the maximum allowable operating pressure (MAOP) in Class 3 and 4 areas. Line 147 was tested in October, 2011 to a minimum spike test pressure of 669 psig followed by a minimum 8-hour hold pressure of 607 psig.[14] The 8-hour test qualifies Line 147 to operate with an MAOP of 400 psig in accordance with regulations. The October 2011 tests fulfill the requirement of the CPUC that where design information could not be established from documentation, hydrostatic pressure testing be used to validate the MAOP.[15] Note that relatively recent replacement sections had been installed in 1987 and 1990 and had been tested at the time of installation to higher pressure (1,240 psig and 1,050 psig, respectively). Those tests were not performed using the spike test format as that method of testing was not then, nor is it now, commonly used or considered necessary with new pipe.

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[6] Bergman, S.A., "Why Not Higher Operating Pressures for Lines Tested to 90% SMYS?", Pipeline & Gas Journal, Dec., 1974.

[7] Kiefner, J.F., "Role of Hydrostatic Testing in Pipeline Integrity Management", Northeast Pipeline Integrity Workshop, Albany NY, June 12, 2001.

[8] ASME, B31 Code for Pressure Piping, Section 8, "Gas Transmission and Distribution Piping Systems", B31.8-2012.

[9] ASME, B31 Code for Pressure Piping, Supplement to B31.8, "Managing System Integrity of Gas Pipelines", B31.8S-2012.

[10] Code of Federal Regulations, Title 49 – Transportation, Subpart D, Part 192 –Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards", 49 CFR 192, 2012.

[11] Canadian Standards Administration, "Oil and Gas Pipeline Systems", CSA Z662, 2011.

[12] International Standards Organization, "Pipeline Transportation Systems", ISO 13623:2009.

[13] Kiefner, J.F., and Maxey, W.A., "The Benefits and Limitations of Hydrostatic Pressure Testing", API Pipeline Conference, 2000.

[14] Testing was completed in four test sections with slightly differing final record pressures in each section. The test pressures reported herein were the lowest spike or hold pressures reported, each from any one section but not necessarily from the same section.

[15] Memorandum from the Commission's Consumer Protection and Safety Division to Pacific Gas & Electric Company, September 12, 2011.

The pressure test data indicates that no yielding occurred during the tests. This suggests that no pipe with either extremely low-strength material or extremely thin wall was present. The successful completion of the tests without ruptures also verified that no pipe containing seams that are susceptible to failure at high stresses, such as poorly bonded lap-welded pipe, was present.

The Line 147 pressure tests were performed as "spike tests", in accordance with the recommendations of NTSB[16] and the CPUC. A spike test format involves taking the line to a high pressure for a short duration, typically between 10 minutes and 1 hour, then lowering the pressure approximately 10% for a long hold period.[17] The purpose of testing in this manner is to reduce or eliminate the chances of a "pressure reversal" which is a phenomenon where a pipeline fails at a lower pressure than a recent high pressure condition. Reversals occur where an existing flaw very close to the point of failure during the test enlarges but does not fail before the test is concluded. The flaw is incrementally more severe as a result, causing the pipe to fail later at a lower pressure. In addition, damage from compressive yielding at the crack tip upon sudden depressurization during a prior test failure, and the consequent exhaustion of ductility in low-toughness materials, are contributing factors.[18] The problem manifests itself as repeated test failures or as a failure in service soon after a test to a higher pressure, and is observed most often with early vintage ERW pipe having low-toughness seams where pressure tests above prior historical levels are attempted. The best protection against a pressure reversal is (a) using the spike test format which avoids causing further damage to surviving defects during the long hold period, (b) avoiding overly aggressive test levels in certain varieties of pipe (namely lap-welded pipe, and early vintage ERW pipe that has demonstrated prior susceptibility to seam failures), and (c) observing a generous test margin between the spike pressure and the operating pressure. The October 2011 spike tests provided for a test pressure ratio of at least 1.67 which is greater than the magnitude of pressure reversals reported in the literature, essentially assuring that a pressure reversal that consumes the entire test margin is extremely unlikely.

While hydrostatic pressure testing is considered the benchmark for any alternative integrity assessment method, hydrostatic testing does have three important limitations. One is that it may only assure integrity for a finite period of time. If surviving flaws can enlarge in service by some mechanism such as corrosion or fatigue crack growth, then the factor of safety will reduce over time in proportion to the defect growth rate. The assessment may have to be repeated after some number of years. Larger test pressure ratios therefore result in longer reassessment intervals, but the pressure test (or an assessment using an alternative method such as in-line inspection) may still have to be repeated.

A second limitation is that a pressure test is not an effective assessment for the integrity of girth welds, or most other construction-related conditions. The reason for this is that defects fail under a stress that is perpendicular to the defect orientation and the longitudinal stress induced by internal pressure is only about 30% of the circumferential stress. Thus low-strength girth welds could readily survive a pressure test even to a very high level. As will be discussed below under the review of integrity threats, low-strength girth welds are not an integrity

[16] NTSB, Safety Recommendation P-10-004, January 3, 2011.

[17] Rosenfeld, M.J., "Hydrostatic Spike Pressure Testing of Pipelines – Why and When?", Presentation to American Gas Association, Operations Conference, Orlando, May 22, 2013.

[18] Kiefner, J.F., Maxey, W.A., and Eiber, R.J., "A Study of the Causes of Failures of Defects that have Survived a Prior Hydrostatic Test", Pipeline Research Committee, American Gas Association, NG-18 Report No. 111, Nov. 3, 1980.

concern where internal pressure is the primary loading. They usually remain stable unless the pipeline is acted on by large external loadings.[19]

The third limitation is that a hydrostatic pressure test does not provide immunity against the occurrence of leaks. It is not uncommon for operators to discover leaks sometime after conducting a pressure test. In fact just such an event occurred in Line 147. There several reasons for this:

- One is that defects that are very short axially, but deep with respect to the wall thickness, could survive even a very high pressure test, and there is very little difference in size between a short, deep defect that survives a test and a short, deep defect that will leak in service. If the surviving flaw can get deeper for any reason, such as with a small, isolated, but deep corrosion pit, it may not take long after a hydrostatic test for it to become a leak.
- Another reason is that some leaks are too small to detect during the hydrotest. A finite quantity of fluid has to be lost, depending on the pipe diameter and test section length, to be sensed as a 1-psig pressure loss. Very small leaks discovered after a test could have leaked unnoticed during the test, and may have leaked undetected while in service before the test.
- Finally, very small, tight flaws in seam welds or girth welds may be initially blocked by welding slag or high temperature oxide.[20] Such oxides are not inherently strong materials but can often withstand pressure because they occupy small volumetric spaces reinforced by the surrounding metal. The high stress level imposed during the test could potentially open the volumetric spaces enough to cause the adherent oxide layer to crack. Over time, the oxides may then dissolve or erode, allowing a leak path to communicate through the pipe wall. Usually this only occurs in very small flaws that would only cause a small but detectable leak, not a rupture. This circumstance has been observed with certain types of ERW seam flaws, and this appears to have been the case with the repair weld discovered at MP 2.29.

Leaks are more reliably detected and mitigated through a leak-detection program than by hydrostatic pressure testing. The occurrence of a leak during a test or some time afterward does not negate the test's proof of the strength of the pipe and proof of an absence of gross defects that could cause a rupture at the operating pressure.

Task 3. Determine Whether the Integrity of Line 147 has Degraded Since the 2011 Hydrostatic Test

The question of whether the 2011 hydrostatic test is still a valid indicator of the integrity and fitness for service of the pipeline can be understood in terms of two issues: (1) whether there is evidence that integrity threats mitigated by the 2011 test have worsened during the two years subsequently; and (2) whether integrity threats not mitigated by the 2011 test appear to be affecting the pipeline. These issues were addressed by considering each category of pipeline integrity threat identified for integrity management purposes by ASME B31.8S and as supplemented in 49 CFR 192, Subpart O – Gas Transmission Pipeline Integrity Management, Paragraph 192.917. The integrity threats specified by ASME B31.8S are: external corrosion,

[19] Kiefner, J.F., "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines", US Department of Transportation, Office of Pipeline Safety, Contract DTFAAC05P02120, April 26, 2007.

[20] Kiefner, Stability of Manufacturing and Construction Defects.

internal corrosion, stress-corrosion cracking, pipe manufacturing defects, construction/fabrication-related defects,[21] equipment,[22] mechanical damage,[23] incorrect operation, and natural events.[24] Federal regulations supplement the potential threats list by requiring specific procedures to address the following conditions: those that could cause fatigue, pipe manufacturing, construction, or ERW seams that have experienced prior failures or where an increase in operating pressure has occurred, and coating materials and environments where corrosion has previously occurred; however, these remain elaborations of integrity threat categories already defined by B31.8S. Each threat category was examined in light of available information to ascertain whether important, or any, degradation in the integrity of Line 147 has occurred since the 2011 hydrostatic test.

1. External Corrosion

Corrosion is a natural process driven by chemical energy that seeks to reduce the binding energy of metals. At the anode, iron ions become dissociated from the pipe surface, releasing electrons that travel a conductive path to the cathode where they combine with hydrogen ions to preserve overall electrical neutrality, evolving hydrogen gas in the process. External corrosion of steel pipelines in the soil environment is prevented by an external barrier coating. However, all pipeline coatings are potentially susceptible to a number of damage or deterioration mechanisms (e.g., mechanical damage, cracking, disbondment) over time. Corrosion being an electrochemical process involves the flow of electrons. Cathodic protection (CP) controls corrosion by the application of a voltage so as to assure that electrical current flows from the soil environment onto the pipe surface at all points where the pipe surface is exposed. Steel gas pipelines are required by regulations to be cathodically protected. The functioning of the CP system is monitored by periodically checking the pipe-to-soil electrical potential at test leads spaced at long intervals (e.g. every half mile to several miles) along the pipeline. Regulations and industry standards specify that potentials more negative than −850 millivolts (mV) indicates effective cathodic protection (there are other criteria that can be used as well). PG&E has monitored CP levels at five test points along Line 147 periodically every 2 months. Only 2 of 63 pipe to soil readings during the 2 years since the 2011 hydrostatic test fell below the −850 mV criterion. The low readings were only slightly below the −850 mV criterion (−841 mV −797 mV) and persisted for only a single monitoring interval. In addition, close-interval surveys may be used to check pipe-to-soil potentials, voltage gradients, or electrical current flow patterns at closer spacing (e.g. every 3 ft). PG&E had conducted close-interval surveys of 500 ft of Line 147 conducted in 2013 after the leak at MP 2.29 and identified no concerns.

[21] The construction/fabrication-related defects category includes a features associated with older vintage or obsolete methods of constructing pipelines such as couplings, miter bends, and wrinkle bends, as well as defective girth welds or fabrication welds (but not seam welds made during manufacturing of pipe).
[22] The equipment-related integrity threats category includes faulty mechanical equipment or components thereof, and failures of pressure relief and pressure control devices or systems.
[23] The mechanical damage category includes damage caused by contact from any type of equipment that works in the soil (such as construction or agricultural equipment) and operated by any party (the operator, his contractor, or an unaffiliated person), latent damage caused previously, and vandalism.
[24] The natural events category includes flooding, storms, frost heave, earthquake, ground subsidence, and slope instability, among many other phenomena.

The 2011 hydrostatic test verified that no external corrosion existed at that time that could cause a rupture. The CP surveys indicate that the corrosion prevention system has continued to provide effective mitigation of external corrosion.

2. Internal Corrosion

Internal corrosion occurs in natural gas pipelines where either significant quantities of free water accumulate, or where moisture plus gas impurities such as CO_2 are present enabling the formation of acidic fluids. Moisture enters natural gas pipelines from gas production or storage formations. Line 147 is well downstream of gas production or storage wells and transports consumer quality gas that has sufficiently low levels of moisture and impurities that internal corrosion is not an integrity threat.

Two drips are located in Line 147. Drips are installed at low points to collect liquids. Since the gas flowing through Line 147 is very dry, one could speculate that the presence of the drips implies that moisture control may not have been as assured in 1957 as it is today. Nondestructive examination (NDE) by ultrasonic and radiographic testing of the drip at MP 0.52 was completed within the past week. The NDE confirmed that no internal metal loss or accumulation of liquids has occurred in the pipeline adjacent to the drips.

Operating conditions suggest that internal corrosion is not an integrity threat currently affecting Line 147, but the 2011 pressure test was equally effective for proving the integrity of the pipeline with respect to internal corrosion as with external corrosion. Recent inspections indicate that no changes in conditions have occurred, such as an accumulation of liquids.

3. Stress-Corrosion Cracking

Stress-corrosion cracking (SCC) is a form of environmentally induced cracking. SCC requires three factors to be present: a susceptible material (which all commonly used grades of line pipe are), a tensile stress (which is usually present with a pressurized pipe), and a conducive environment. Two forms of SCC are recognized to affect natural gas pipelines, "high-pH" and "near-neutral-pH". Typically only one form of SCC affects a pipeline, and not all pipelines are susceptible to either form of SCC.

High-pH SCC occurs in a narrow range of cathodic potentials, −600 mV to −750 mV and pH above 9 representing an impaired cathodic condition,[25] and elevated pipe operating temperatures (usually in excess of 90 F) associated with operating downstream of compressor stations that do not practice aftercooling. Near-neutral-pH SCC occurs in an absence of cathodic protection and pH between 5.5 and 7.5, normal soil temperatures, and strictly anaerobic conditions. Soil type, hydrology, and coating type affect the potential for the local environment at the pipe surface to support SCC.

Both forms of SCC require the presence of a moderate to high tensile stress, oriented either longitudinally or circumferentially. Stresses below 50% of SMYS are generally considered to indicate a low susceptibility to SCC even if the electrochemical environment that supports SCC is present. At the MAOP of 400 psig, Line 147 would operate at hoop stresses less than 50% of SMYS based on known pipe attributes, including the reconditioned pipe. The calculation of hoop stress as a percentage of SMYS does not account for seam joint efficiency factors that are

[25] National Energy Board, "Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines", Report of the Inquiry, MH-2-95, November 1996.

less than 1.0, which need not be considered in the calculation when reconfirming or revising the MAOP under Paragraph 192.611 based on a pressure test.[26]

Line 147 does not operate downstream of compression or at warm temperatures, and is therefore not considered to be susceptible to high-pH SCC. PG&E reportedly has never identified SCC of either type in its system. It is noted that the conditions that support microbe induced corrosion (MIC) are similar to those that support near-neutral-pH SCC except for the stress threshold. PG&E has not heretofore identified MIC or suspected MIC on Line 147, so the conditions that would support near-neutral-pH SCC appear to be absent.

SCC does not appear to be an integrity threat of concern with Line 147, but the 2011 pressure test was effective to establish the integrity of the pipe with respect to SCC. The CP readings indicate that cathodic protection levels continue to be maintained at levels effective for prevention of SCC.

4. Pipe Manufacturing Defects

Pipe longitudinal seams are potentially susceptible to failure due to enlargement in service due to the effects of operational pressure cycles acting on resident defects. As discussed above, pressure testing of pipe to a high stress level assures that gross defects are not present. The most severe pipe manufacturing defects are eliminated by hydrostatic pressure testing of pipe joints at the pipe mill. API 5L increased mill test pressures to 60% of SMYS in 1942, 85% for all X-grades in 1949, and 90% SMYS for 20-inch OD and larger pipe in 1956. The hydrostatic pressure tests performed in 2011 in a few cases likely exceeded the pipe mill test (specifically, the older varieties of pipe having designated SMYS of 33 ksi, 40 ksi, and 45 ksi).

Natural gas pipelines tested to an adequate margin above the MAOP are not generally susceptible fatigue crack growth (especially relative to liquid transportation pipelines).[27,28] The occurrence of the San Bruno incident demonstrated that absent a pressure test to a sufficient level that eliminates gross defects, pressure cycles in natural gas service can induce fatigue, and is not inconsistent with the findings of referenced studies. A pressure test to 1.25 times the MAOP has been considered adequate to avoid this problem in a highly-stressed pipeline, because the test imposes a very high stress that only small flaws can survive. However, 1.25 times MAOP may not be adequate for a pipeline operating at low to moderate stresses because the stress imposed by the test is low enough to be survived by comparatively large defects. Large defects grow faster by fatigue than small defects. Therefore, it is necessary to increase the test pressure ratio from 1.25 in pipe operating at low to moderate stress levels as Line 147 does.

The 2011 tests were conducted to at least 2 times the 330 psig operating pressure which is generally sufficient to assure that fatigue induced by pressure cycles in natural gas service will not produce a failure in less than a period on the order of 100 years, or longer. This was verified by Kiefner by performing fatigue calculations of the pipe in Line 147 using established

[26] DeLeon, C., Assoc. Dir. for Pipeline Safety Regulation, letter to Dolgoy, D., PHMSA Interpretation PI-79-035, October 12, 1979.

[27] Kiefner, Stability of Manufacturing and Construction Defects.

[28] Kiefner, J.F., and Rosenfeld, M.J., "Effects of Pressure Cycles on Gas Pipelines", Gas Research Institute, GRI-04/178, September 17, 2004.

fracture mechanics principles.[29] In all cases the calculated times to failure were in excess of 500 years (an artificial cap we impose to reduce calculation time).

The pipe installed in 1987 and 1990 were not part of the 2011 tests, but they were tested at the time of construction to very high pressures. Their calculated times to failure were also in excess of 500 years. It is noted that those were new pipe manufactured to modern specifications that include effective NDE and pressure tests at the pipe mill prior to the hydrostatic field tests.

Based on these results and overall considerations for the value of hydrostatic pressure spike testing, Line 147 is not expected to be susceptible to premature failure in pipe seam or pipe body manufacturing defects.

5. Construction/fabrication defects

The principal concern with construction or fabrication-related integrity threats are the installation of components associated with now-obsolete construction methods such as wrinkle bends, miter bends, or couplings (for example), or low-strength or poor quality girth welds. Such components generally do not fail solely due to internal pressure. The explanation for this is that, in a buried pipeline, the longitudinal stress (which is the stress component that would act to separate a girth weld, coupling, bend, or other feature) is only 30% of the hoop stress. So even in a pipeline operating at a very high hoop stress, the stress component induced by pressure acting to separate the pipeline feature is very low. Instead, these types of pipeline features are usually stable unless they become exposed to very high external loadings, typically soil movement associated with natural events. Consequently the 2011 pressure test was not an effective assessment or mitigation for this integrity threat category. Line 147's exposure to threats associated with natural events is discussed later in this report, so this section focuses on whether potentially threatened components exist within Line 147.

A review of the PFL identified no wrinkle bends or couplings present in Line 147. It is certainly possible that many original girth welds were never nondestructively inspected by radiographic testing (RT). RT of girth welds was not widely practiced in pipeline construction until the mid-to-late 1950s. Codes and regulations continue to only require that 10% of girth welds (randomly selected) be inspected in Class 1 areas, 15% in Class 2, and 90% in Class 3 and 4 areas. Records do indicate that the 1987 and 1990 pipe replacements were inspected by RT. No historical girth weld leaks or failures were identified in Line 147.

Line 147 does contain two features that required further consideration: a span across a ditch and a miter bend in a buried section of the pipeline just beyond the span. The span, located at MP 0.52, is 61 ft long. The span was inspected by PG&E and identified to be either SSAW pipe of unspecified origin. The seam had been radiographed and was determined to meet fitness-for-service seam quality criteria.[30] The buried approach to the span runs downhill to a 40-degree mitered bend. Between the bend and the span is a concrete anchor. PG&E had previously had a structural analysis of the bend, anchor and span assembly performed,[31] which

[29] Kiefner, J.F., Kolovich, C.E., Zelenak, P.A., and Wahjudi, T., "Estimating Fatigue life for Pipeline Integrity Management", International Pipeline Conference, IPC04-0167, Calgary, October 4-8, 2004.
[30] PG&E, Applied Technology Services, "Pipe Characterization and Weld Assessment, San Carlos, Line 147, MP 0.52", ATS Report # 413.61-13.28, 01/29/2013.
[31] Hart, J.D., SSD, Inc. letter to GTS, Inc., August 17, 2011.

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determined that the pipeline met applicable allowable stress levels. For conservatism, Kiefner reanalyzed the span considering a pipe specification corresponding to first-generation A.O. Smith line pipe and arrived at the same conclusion. Based on these findings, neither the span nor the miter bend are deemed to pose an integrity threat.

6. Equipment

PG&E reviewed its gas event reporting tool and gas transmission leak reports. No leaks have been identified on Line 147 as a result of equipment failure. Line 147 does not appear to be susceptible to any specific integrity threat associated with equipment failure.

7. Incorrect Operation

The principal incorrect operation conditions that could affect Line 147 are overpressure events. Line 147 may have experienced overpressure events prior to the 2011 hydrostatic pressure test but subsequent to the 1987 and 1990 tests. These were accounted for in the analysis of those replacement sections, but any adverse effect outside of those sections would have been neutralized by the successful 2011 tests. No overpressure occurrences appear to have occurred after the 2011 tests. Assuming PG&E continues to perform its routine maintenance and operations activities in accordance with its procedures, Line 147 does not appear to be susceptible to any specific integrity threat associated with incorrect operation.

8. Mechanical Damage

Mechanical damage refers to damage caused by accidental contact between mechanized equipment and the pipe surface. Examples of equipment that can cause such damage include backhoes, bulldozers, plows, ditchers, and borers, to name a few. Mechanical damage introduces a scrape or gouge, usually in conjunction with an indentation (though the indentation may re-round under internal pressure in the pipe). The resulting damage is highly detrimental to the strength of the pipe due to surface and subsurface metallurgical damage locally to the scrape or gouge. There are no reliable methods for calculating the safe operating pressure of a piece of pipe affected by mechanical damage, although pipe operating at low to moderate stresses can tolerate more severe damage than pipe operating at the highest stresses. In any case, all pipeline standards and regulations require pipeline operators to conduct vigorous damage-prevention programs, respond promptly to requests by excavators to locate buried pipelines, and to promptly repair the pipe where mechanical damage is discovered to have affected the pipe. PG&E actively engages in a variety of damage prevention practices and programs.

Hydrostatic pressure testing is an effective way to assure that gross mechanical damage is not present on a pipeline. However, minor damage could survive a pressure test, while damage could have been incurred after a test. Minor damage that survived the 2011 test would not be considered an immediate threat, while the low operating stress characterizing Line 147 provides some damage tolerance. When PG&E implements either in-line inspection or external corrosion direct assessment method with a future assessment for integrity management, latent damage will likely be detected.

PG&E's line-locate and dig-in data was reviewed in order to gage the potential risk of new mechanical damage affecting Line 147 after the 2011 hydrostatic test. Over the 2-year period from October 2011 to the present, PG&E experienced 4,089 dig-ins (unnotified excavations) for

1,367,356 locate requests, for a dig-in rate of 0.003, or 0.3%. The data encompassed 42,000 miles of distribution piping and 6,700 miles of transmission piping operating at greater than 60 psig. Over the same 2-year period, there were 972 locate requests in the vicinity of Line 147, and 3 dig-ins (within a wide buffer zone around the line but not immediately near the pipeline), or about 0.3%. This shows that Line 147 is typical in terms of susceptibility to dig-ins based on land use and other primarily societal factors, and that there is no reason to expect an unusually high rate of dig-ins to affect Line 147. PG&E has indicated that on average 5 leaks per year due to dig-ins occur in the 6,700 mile gas transmission system. Because Line 147 exhibits an average threat level for dig-ins, the expected rate of occurrence of leaks due to this cause in the 4-mile long Line 147 will be proportionately low (i.e., at a frequency less than once every 300 years). No leaks have occurred due to dig-ins in Line 147 since the 2011 test. The likelihood of Line 147 currently being seriously affected by latent, old damage that survived the 2011 pressure test, or by new damage that occurred after the test, is deemed to be very low.

9. Natural Events

PG&E discussed its knowledge about the geotechnical conditions affecting the area crossed by Line 147. The area is not affected by known seismic faults or liquefaction zones.

The only geotechnical circumstance of interest is that erosion has exposed approximately 100 ft of Line 147 at MP 1.80. A geotechnical specialist recently evaluated the conditions at the site to determine whether the exposure was associated with past or imminent landslide conditions, and whether the site exhibited evidence of recent changes in condition.[32] The geotechnical evaluation considered observable conditions on site, prior geotechnical investigations and available geologic maps, and reported observations of local residents. The evaluation concluded that the pipeline was not constructed across a prior or present active landslide area. The report also concluded that the pipeline had been installed on a bench across the slope and fill placed to match the slope angle. Over time the fill had eroded without being accompanied by movement of the slope, and that the erosion had occurred many years earlier. PG&E conducted a survey of the pipe alignment extending several hundred feet upstream and downstream of the exposure. The alignment appeared to be perfectly straight within the tolerance of the buried line locator), which substantiates the conclusion that no slope movement had taken place. While the pipe exposure is not a desired condition, in this case it does not appear to be causing distress to the pipeline in the form of added stresses or loadings that could act to separate girth welds or other construction features. PG&E plans to implement additional mitigations for the exposed condition of the line.

This completes my evaluation of the status of Line 147. If you have further comments or questions please feel free to contact me.

Sincerely,

Redacted

[32] de La Chappelle, J., and West, D.O., Golder Associates, Inc., letter to Barnes, B., PG&E, October 15, 2013.