Critical crack path assessments in failure investigations

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ABSTRACT. This paper presents a case study in which identification of the controlling crack path was critical to identifying the root cause of the failure. The case involves the rupture of a 30-inch (0.76 m) natural gas pipeline in 2010 that tragically led to the destruction of a number of homes and the loss of life. The segment of the pipeline that ruptured was installed in 1956. The longitudinal seam of the segment that ruptured was supposed to have been fabricated by double submerged arc welding. Unfortunately, portions of the segment only received a single submerged arc weld on the outside, leaving unwelded areas on the inside diameter. Post-failure examination of the segment revealed that the rupture originated at one of these unwelded areas. Examination also revealed three additional crack paths or zones emanating from the unwelded area: a zone of ductile tearing, a zone of fatigue, and a zone of cleavage fracture, in that sequence. Initial investigators ignored the ductile tear, assumed the critical crack path was the fatigue component, and (incorrectly) concluded that the root cause of the incident was the failure of the operator to hydrotest the segment after it was installed in 1956. However, as discussed in this paper, the critical path or mechanism was the ductile tear. Furthermore, it was determined that the ductile tear was created during the hydrotest at installation by a mechanism known as pressure reversal. Thus the correct root cause of the rupture was the hydrotest the operator subjected the segment to at installation, helping to increase the awareness of operators and regulators about the potential problems associated with hydrotesting.

KEYWORDS. Fatigue; Rupture; Ductile Tear; Pressure Reversal; Hydrotest.

INTRODUCTION

The Pacific Gas and Electric Company (PG&E) owns and operates an extensive natural gas pipeline transmission system throughout Northern California. One of those pipelines, known as Line 132, is a 30-inch (0.76 m) nominal pipe that transports natural gas up the San Francisco Peninsula to the City of San Francisco itself. The maximum allowable operating pressure (MAOP), as set in accordance with applicable regulations, is 400 psig (2.76 MPa). It typically operates at less than 375 psig (2.59 MPa). The pipeline was originally installed in circa 1948 at a time when the natural gas distribution system in the United States was being built to accommodate demand and transport gas from sources, such as the Permian Basin in the Southwestern United States, to markets, such as San Francisco. In 1956, a subdivision of the City of San Bruno was to be built over a portion of the right-of-way of Line 132. To accommodate the subdivision, a portion of the line known as Segment 180 was relocated. Part of this relocation involved a portion of piping consisting of six short pieces of pipe, known as pups, each approximately 5 to 6 feet (1.52 to 1.83 m) long, joined together.

On September 9, 2010, Line 132 ruptured in this assembled pup section. The pressure at the point of rupture had reached 383 psig (2.64 MPa) at the time of rupture but was still below the MAOP. Examination showed that the rupture started in Pup 1 and extended some 28 feet (8.54 m). The force of the rupture created a large crater in the ground and ejected a large piece of the pipeline as shown in Fig. 1. The released cloud of natural gas ignited, causing considerable loss of life and property damage in the surrounding subdivision.

The National Transportation Safety Board (NTSB), the part of the US Department of Transportation charged with investigating accidents such as this, investigated the incident and prepared a report [1]. Other organizations conducted investigations as well. Some investigations reached the conclusion that the root cause of the incident was the failure of PG&E to hydrotest Segment 180, including the pup section, as required by applicable industry standards when Line 132 was relocated in 1956. However, this root cause conclusion is not correct, because these investigators did not identify the critical crack path that ultimately led to the failure. As discussed in this paper, identifying the correct critical path required careful review of available historical and current documents and reports, detailed microscopic examination of the fracture surfaces, and burst pressure calculations performed in accordance with methods consistent with industry codes and standards.

Figure 1: Photograph taken the day after the incident showing the ruptured segment of Line 132 that was ejected from the ground by the force of the rupture. Source: www.dailyrepublic.com.

PIPE MANUFACTURING PRACTICES

Segment 180 of Line 132 consists of pipe that is nominally 30 inches (0.76 m) in diameter and 3/8-inch (0.009 m) thick. Fabrication of such pipe starts with a flat steel plate, called a skelp, which is then rolled into a cylindrical shape in a pipe rolling machine and welded longitudinally to join the mating edges. The longitudinal seam weld can be made using one of several welding processes. One such process, and the one used to fabricate Segment 180 pipe circa 1948, is called double submerged arc welding (DSAW), which involves welding the seam from both the inside and outside of the pipe, with each weld penetrating more than half way through the thickness of the seam. A metallographic cross section of a proper DSAW seam is shown in Fig. 2.

Given the 30-inch (0.76 m) diameter of the pipe in Segment 180, the steel plate used to manufacture the pipe would have been over seven feet (2.13 m) wide. Rolling 3/8-inch (0.009 m) thick steel plate into a pipe requires large machinery that exerts tremendous force. Based on experience reviewing both pipe manufacturing and gas transmission pipeline operations, as well as reviewing records reflecting historic purchase orders and purchasing practices of PG&E and other gas pipeline operators, gas transmission pipeline operators (including PG&E) do not manufacture such pipe; rather, they purchase such pipe from pipe mills. Following receipt of pipe from a mill, a pipeline owner/operator (or contractor hired by them) lays the pipe segments in the ground and welds them together with circumferential welds (which are also referred to as "girth welds").

DSAW pipe is considered by metallurgists in the gas transmission pipeline field today to be one of the highest quality welded pipe. The same was true in 1956 when Segment 180 was constructed and installed. At the time, given the pipe manufacturing techniques available for 30-inch (0.76 m) diameter pipe, DSAW pipe was the highest quality pipe of that size that PG&E could have used for Segment 180. There is no stronger practical way to join together the two edges of a large piece of metal rolled into gas transmission pipe.

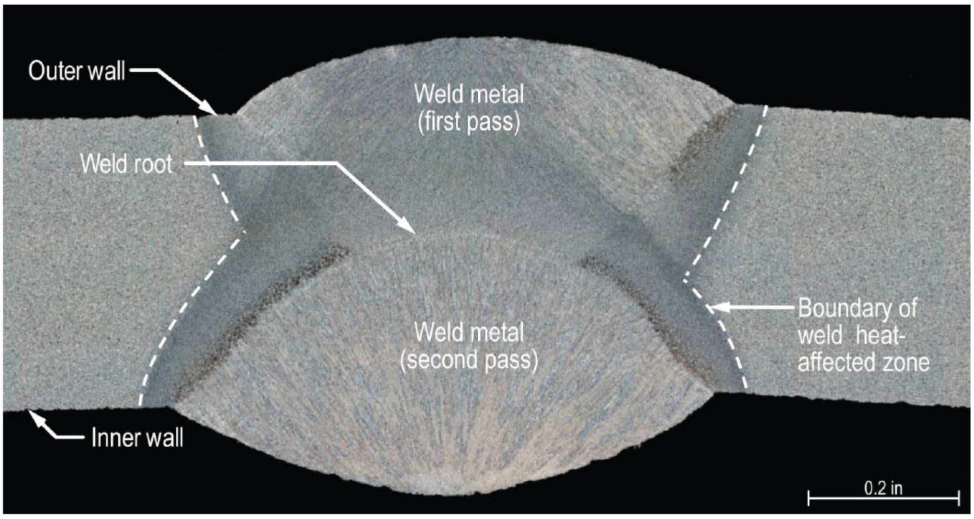


Figure 2: Metallographic cross section of a proper DSAW weld from NTSB Final Report, Fig. 19b.

Absent any corrosion damage, well-manufactured DSAW pipe from the late 1940s or early 1950s would not have needed replacement merely due to its age in 2010 under any industry practice or standard. Between installation of Segment 180 in 1956 and the September 2010 accident, there would be no reason to believe that any soundly manufactured piece of DSAW pipe would be at risk of rupturing. Certainly, the increase in pressure experienced by Segment 180 on September 9, 2010, would not have caused properly made DSAW pipe to fail.

As noted earlier, Segment 180 was constructed with 30-inch (0.76 m) diameter, 0.375-inch (0.009 m) wall thickness DSAW pipe. However, an approximately 23-foot (7.01 m) long portion of Segment 180 – the section of pipe that ruptured – contained several short pieces of pipe commonly referred to as "pups." Specifically, the approximately 23-foot (7.01 m) section of pipe was made up of six pups, from south to north. Those pups are referred to as Pup 1 through Pup 6. These pups ranged in length from 3.5 to 4.7 feet (1.07 to 1.43 m) in length. The use of pups was a common industry practice for pipelines constructed in the late 1940s and early 1950s.

ROOT CAUSE ANALYSIS: SEGMENT 180 RUPTURE

Based upon visual and metallurgical analysis of the subject pipe, it is clear that portions of Segment 180 – namely pups 1, 2, and 3 – were missing the interior seam weld found in properly fabricated DSAW pipe as shown with respect to Pup 1 in Fig. 3. Tensile testing conducted by the NTSB indicated that the base metal in Pup 1 through Pup 6 did not meet the 52,000 psig (358 MPa) strength requirement specified by PG&E in purchases of 30-inch (0.76 m) pipe in the late 1940s and 1950s. Further, the directionality of manganese-sulfide stringers determined during metallographic examination indicated the rolling direction of Pup 1 through Pup 3 was in the circumferential direction rather than the longitudinal direction associated with full lengths of pipe manufactured at a mill. This indicates the pups were not cut from longer pipe sections but were individually fabricated from smaller pieces of plate oriented 90 degrees from full length pipe rolling operations. Given that the rupture initiated through weld metal in Pup 1, the lower-than-specified base metal strengths exhibited in Pup 1 through Pup 6 and transverse rolling direction orientation in pups 1, 2, and 3 did not contribute to the rupture. The length of the pups (less than 5 feet (1.52 m)) also had no relationship to the root cause of the accident.

The failure of Segment 180 was in part due to the missing interior seam weld in Pup 1. However, the missing weld in and of itself was not sufficient to cause the rupture in Pup 1 on September 9, 2010. Two additional factors were also necessary to cause the pipeline failure in San Bruno: (1) ductile tearing at the root of the exterior longitudinal seam weld on Pup 1; and (2) fatigue cracking that initiated and grew from the ductile tear slowly over time by the action of normal operational pressure fluctuations in the pipeline. This fatigue cracking grew to a point that the relatively small increase in pressure on September 9, 2010, caused the Pup 1 longitudinal seam to rupture. Thus, the root cause of the failure was the unique combination of three factors; the elimination of any one of which, and the rupture would not have occurred.

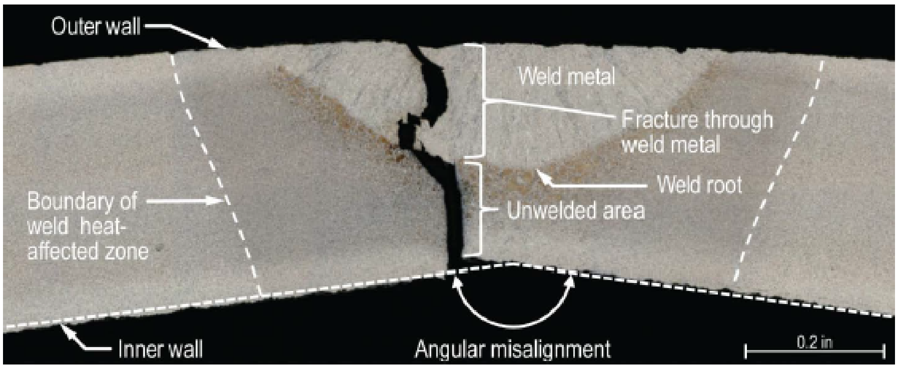


Figure 3: Metallographic image from NTSB Final Report (Fig. 19a) that shows the single-side weld in Pup 1.

Fractographic analysis of the Pup 1 fracture surface provides clear evidence of the ductile tear and the fatigue crack growth zone. A ductile tear is characterized by appreciable plastic deformation and energy dissipation, and is created by a single loading event. A schematic from the NTSB Final Report that highlights the regions of ductile tearing and fatigue cracking is shown in Fig. 4. Ductile fracture morphology, characterized by microvoid coalescence, was observed within the ductile tear region in a scanning electron microscope (SEM), as shown in Fig. 5, and is indicative of ductile tearing. As indicated in the NTSB schematic reproduced in Fig. 4, fatigue crack growth morphology was observed between the ductile tear and the final brittle cleavage fracture zone. Cleavage fracture morphology is characteristic of fast, unstable fracture in steel. Cleavage fracture morphology within the final rupture zone in Pup 1 is shown in Fig. 6.

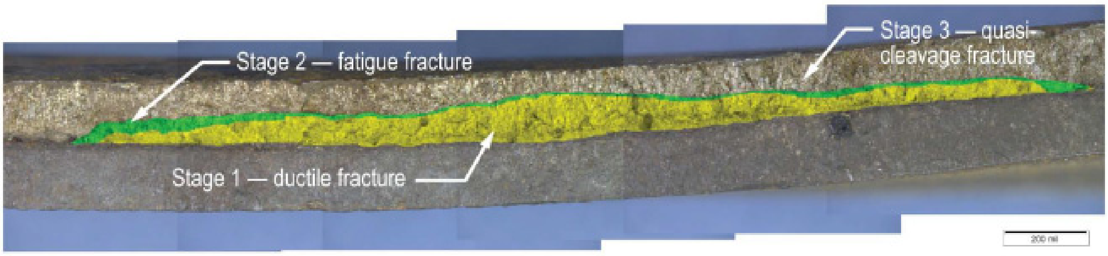


Figure 4: Montage from NTSB Final Report (Fig. 21) that highlights approximate ductile tear (yellow) and fatigue crack growth (green).

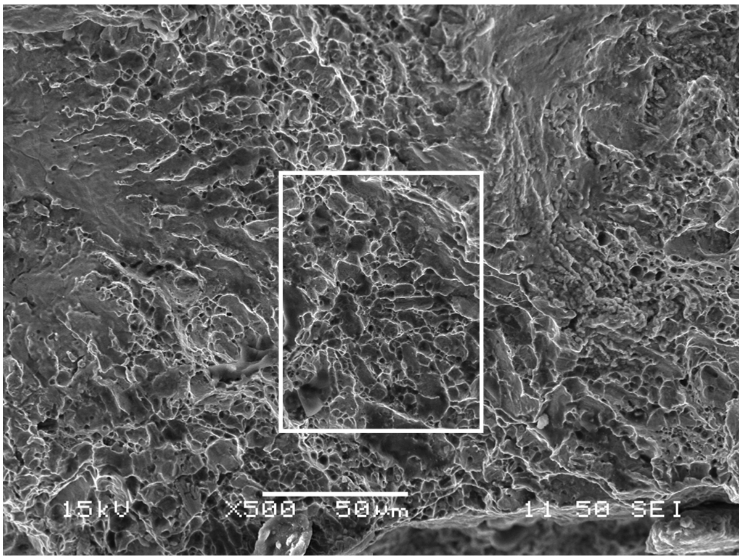


Figure 5: Exponent SEM image that shows microvoid coalescence fracture morphology within the ductile tear (the yellow area in Fig. 3). Representative microvoid coalescence morphology is indicated within the white box.

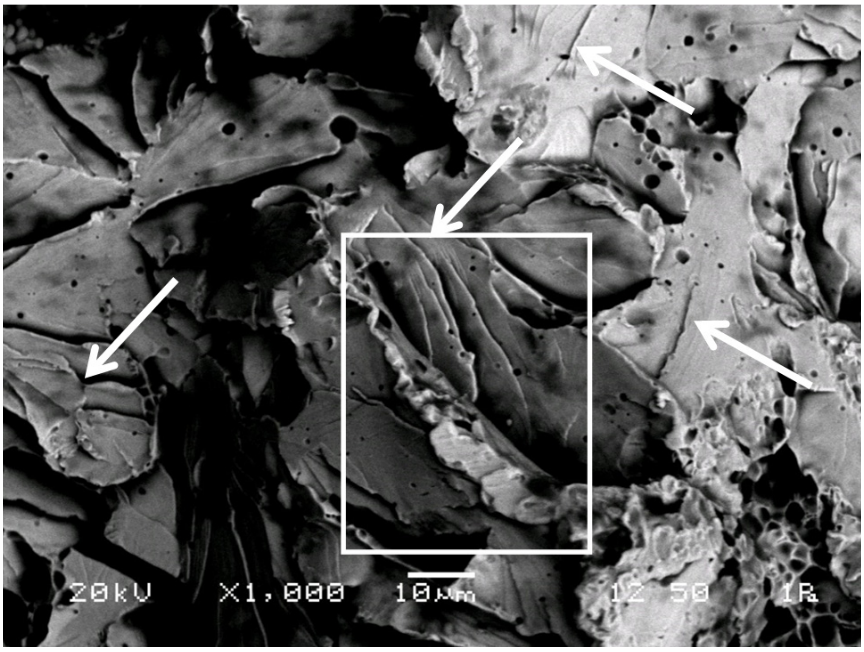
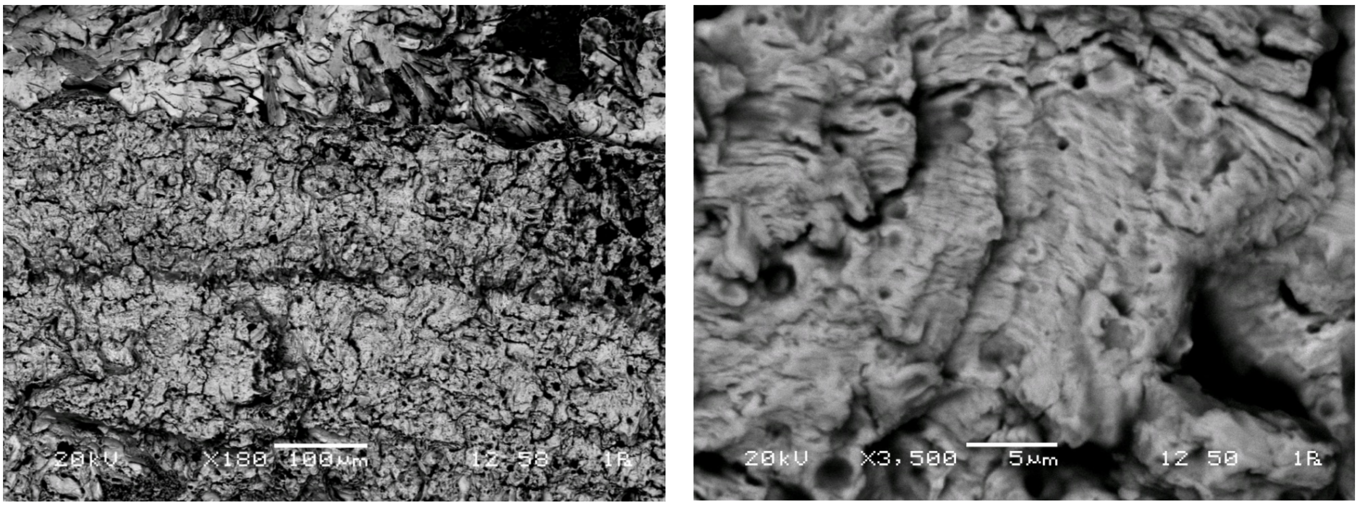


Figure 6: Exponent SEM image of brittle cleavage fracture morphology in Pup 1 final rupture zone. Representative river patterns associated with cleavage fracture are indicated by arrows.

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 crack growth under operational pressure fluctuations, were present at greater depths than the ductile tear as shown in Fig. 7. This indicates that the creation of the ductile tear had to have preceded the initiation and growth of the fatigue cracking. Further, this indicates that the magnitude of the single loading event that caused the ductile tear was greater than the operational pressure fluctuations that later caused the fatigue crack growth.



(a) (b)

Figure 7: Exponent SEM images: (a) Fatigue striations were observed within Regions A & B, between the ductile tear (Region D) and the final brittle fracture (Region C); (b) Close-up of Region B in image (a), showing representative fatigue striations (within the box).

BURST PRESSURE ANALYSIS

The 1955 American Standards Association (ASA) B31.1.8 Code [2] recommended post-installation hydrostatic testing [3] in the field for all gas transmission pipelines expected to be operating above 30% Specified Minimum Yield Strength (SMYS). The 1955 ASA B31.1.8 code provision regarding hydrostatic testing was not mandatory; rather it provided industry guidance. The 1955 ASA B31.1.8 hydrostatic testing recommendation was the first time any voluntary industry guidelines had recommended hydrostatic testing. The preceding 1952 ASA code gave hydrostatic testing little mention, noting that pipeline operators "may" use hydrostatic testing. In a series of 1954 articles, the Chairman of the ASA Committee charged with drafting the 1955 B31.1.8 provisions noted that "it was quite general practice in the gas industry" not to hydrostatically test pipelines. By 1956, when Segment 180 was being installed, the situation had changed little, as the gas pipeline industry had yet to widely adopt hydrostatic testing. Regulations requiring hydrostatic testing of new pipelines did not go into effect in California until 1961 and under federal law until the 1970s.

The ductile tear evident in the weld seam at the Pup 1 rupture origin occurred by two distinctly different fracture mechanisms: tearing and fatigue crack growth. Tearing occurs by a ductile fracture mechanism characterized by relatively wide-scale plastic deformation that typically produces a blunt tip along the leading edge of the tear. (Conversely, the final rupture of the Pup 1 weld occurred by a brittle cleavage fracture mechanism, which is characterized by relatively small scale plastic deformation, a sharp crack tip, and rapid, unstable propagation.) The leading edge of the ductile tear in Pup 1 had been transformed from a blunt tear tip to a sharp crack tip by fatigue crack initiation and growth, which occurred over a relatively long period of time due to normal operational pressure fluctuations in the pipeline. Fatigue crack initiation and growth is a fracture mechanism that occurs under cyclic application of loads typically well below those needed to cause fracture instability or rupture. It is worth noting here that fatigue crack initiation and growth is typically not a concern for gas transmission pipelines because such pipelines generally operate with fewer and smaller pressure fluctuations compared to liquid transmission pipelines. This is because liquids are virtually incompressible, whereas gas is highly compressible. Available data from PG&E pressure records for Line 132 are consistent with this general observation of relatively small pressure fluctuations.

Burst pressure is the internal pressure at which pipe rupture occurs. It is possible to generally reproduce the burst pressures calculated by the NTSB for pups 1, 2, and 3 using the pertinent, accepted ASME Standard, B31G. ASME B31G is used to calculate the failure pressure of pipes with metal loss, which was the situation present in pups 1, 2, and 3 due to the missing internal weld.

Burst pressure calculations per B31G were performed using the Level-2 evaluation technique (RSTRENG method), also called the Effective Area Method. This method allows for a longitudinal metal loss profile that varies in depth along the flaw. Two flaw depth profiles were analyzed: (1) a depth profile that only included the incomplete weld (not including the ductile tear), as conducted by the NTSB; and (2) a depth profile that included both the incomplete weld and the 2.4-inch (0.06 m) blunt tipped ductile tear. Average wall thickness values were taken from NTSB Report 11-056 [4]. The yield stresses used in the B31G calculations were taken from NTSB hardness-based estimates for each pup presented in NTSB Report 11-057 [5]. The results of the ASME B31G analyses depend on a material property known as the flow stress, which is defined as the stress required to cause large-scale plastic deformation in a metal. The B31G Standard presents three different methods for estimating the flow stress σ_{flow}:

$$\sigma_{flow} = 1.1 \times \sigma_y \tag{1}$$

$$\sigma_{flow} = \sigma_y + 10ksi\left(68.9MPa\right) \tag{2}$$

$$\sigma_{flow} = \left(\sigma_y + UTS\right)/2 \tag{3}$$

In these formulas, σ_{flow} is the flow stress, σ_y is the yield stress, and UTS is the ultimate tensile strength. Assuming weld yield stresses from the NTSB and a weld tensile stress of 82 ksi (565 MPa) (based on NTSB-reported weld hardness values for Pup 1), ASME B31G analyses were carried out for pups 1, 2, and 3. Two analyses were done for Pup 1, one analysis for the single-sided weld only and a second analysis for the weld plus the blunt tipped ductile tear. The results of these analyses are tabulated below. The tabulated burst pressures are in psig. Methods 1 through 3 correspond to the three methods of calculating the flow stress shown above. Method 1 was used by the NTSB. As the results in Tab. 1

demonstrate, pups 1, 2, and 3 would be expected to survive a 500 psig (3.45 MPa) hydrotest, even with the presence of a ductile tear in Pup 1.

	Method 1		Method 2		Method 3	
	psig	MPa	psig	MPa	psig	MPa
Pup 1, no tear	525	3.62	594	4.10	718	4.95
Pup 1, with tear	518	3.57	586	4.04	708	4.88
Pup 2	590	4.07	668	4.61	811	5.59
Pup 3	487	3.36	555	3.83	682	4.70

Table 1: Calculated burst pressures for pups 1, 2, and 3.

DUCTILE TEAR ANALYSIS

The stress concentration created by the incomplete seam weld in Pup 1 helped create the ductile tear. Kiefner [6] indicates that ductile tearing can begin at pressures as low as 91% of a pipe's burst pressure. A lower-bound estimate of the pressure required to create a ductile tear can be obtained by taking 91% of the burst pressure estimates for Pup 1 found in Tab. 1. This gives an estimated range of 478 psig to 653 psig (3.30 to 4.50 MPa) for the pressure to cause a ductile tear in Pup 1. Ductile tearing can occur in a stable manner under a single load application, meaning that even though tearing occurs and results in a larger flaw, the pipe can remain intact and capable of retaining pressure without rupture. Thus, a 500 psig (3.45 MPa) hydrotest could have caused the ductile tear in Pup 1 without causing rupture during the test.

A hydrostatic pressure test (hydrotest), in accordance with the 1955 ASA B31.1.8 Standard, would have been performed on Segment 180 to a pressure of 500 psig (3.45 MPa) (1.25 x MAOP). This pressure likely would have been sufficient to create a ductile tear in the one-sided weld of Pup 1 but, as demonstrated in Tab. 1, not burst Segment 180. It is also important to note that no other plausible cause of the ductile tear has been identified. Specifically, PG&E has no record of pressures in Segment 180 ever approaching 500 psig (3.45 MPa) during normal pipeline operation. The NTSB also has ruled out post-installation potential causes such as corrosion, seismic activity, and the 2008 sewer repair [7]. Cold expansion in a pipe mill or a pipe mill hydrotest could not have been the cause of the ductile tear since these activities would have produced stresses far higher than those required to burst the pup. Thus, based on the available information, the ductile tear in Pup 1 was most likely created during a post-installation hydrotest conducted on Segment 180 in 1956.

It is important to note that the hydrotest protocol PG&E is currently following would have revealed the missing interior weld in Pup 1. PG&E is generally hydrotesting pipelines like Line 132 at a pressure 1.7 times MAOP, with a spike test to 10% above this test pressure. In the case of Segment 180, PG&E's current test protocol would subject the pipe to a spike test at 748 psig (5.16 MPa) and a test pressure of 680 psig (4.69 MPa). As indicated by Tab. 1, under this protocol, Pup 1 – or Pup 2 or Pup 3 – would have burst and been replaced.

FATIGUE CRACKING ASSESSMENT

Fractographic examination of the Pup 1 rupture surface clearly indicated that fatigue cracking extended the length and depth of the ductile tear as shown in Fig. 7. The initiation of fatigue cracking from the "blunted" tip of the ductile tear likely took longer than the time it took to grow the initiated fatigue cracking. This is because of the rounded shape of the tip of a ductile tear, as opposed to the sharper tip of a growing fatigue crack.

As the initiated fatigue cracking grew, the strength of the Pup 1 weld gradually decreased. Due to the small size of the pressure fluctuations and the resulting relatively slow growth rates [8], the fatigue cracking would likely have taken decades to reach the size necessary to rupture in September 2010. PG&E's planned pressure increases on December 11, 2003, and December 9, 2008, were only two among many thousands of pressure cycles contributing to fatigue crack initiation and growth, and were not significantly different from any of the other cycles.

Segment 180 operated safely between 1956 and 2010 because the missing interior seam weld and ductile tear were insufficient by themselves to cause the pipe to fail at the relatively low Line 132 operating pressures. The pipe rupture at 386 psig on September 9, 2010, occurred because of initiation and growth of fatigue cracking over a long period of time.

Conclusions

Based on the visual, metallurgical, and fractographic analyses of Pup 1 samples prepared by the NTSB, as well as calculations using established ASME methodologies, it is clear that the September 9, 2010 rupture of PG&E Line 132, Segment 180 in San Bruno, California, was caused by the combination of a missing interior weld, a ductile tear, and fatigue cracking, all of which were present in the Pup 1 longitudinal seam. All three of these factors were necessary for the rupture to have occurred.

Metallurgical analysis indicated that short "pups" at the rupture site were not cut from longer line pipe sections. Based on historical record review and the specialized equipment that would have been required to bend the 3/8-inch (0.009 m) plate into a cylinder, PG&E would not have been able to fabricate these pups. The manufacturer of these pups with the missing DSAW remains unknown.

Calculations and review of available documents indicate that the ductile tear in Pup 1 was most likely created during a post-installation hydrotest conducted on Segment 180 in 1956. PG&E has no record of such a hydrotest, but a former PG&E employee has testified that he remembers a hydrotest in the vicinity of the later pipe rupture. It is important to note that, but for the missing interior weld, this post-installation hydrotest would not have created the ductile tear. A pressure of approximately 500 psig (3.45 MPa) was required to create the ductile tear, which is well above the 400 psig (2.76 MPa) MAOP for Line 132, Segment 180.

The stress concentration created by the missing interior weld and the presence of the ductile tear, combined with normal operating pressure cycles over a long period of time, resulted in the initiation and growth of fatigue cracking. The Segment 180 rupture occurred on September 9, 2010, because the Pup 1 seam weld had been sufficiently weakened by fatigue crack growth to allow rupture at 383 psig (2.64 MPa). Fatigue cracking in Pup 1 developed at a very slow rate, likely requiring the entire 54-year life of the pipe to sharpen the tip of the ductile tear and then propagate to the depth observed at the time of the rupture. The facts and analysis with respect to the fatigue crack growth rate support the conclusion that the ductile tear in Pup 1 was initiated during a 1956 post-installation hydrotest, and that the fatigue cracking developed over time through normal operations until it was large enough to rupture the pipe on September 9, 2010.

References

[1] National Transportation Safety Board (NTSB) 2011, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, Pipeline Accident Report NTSB/PAR-11/01, Washington, DC, (2011).

[2] The American Standards Association – known today as the American National Standards Institute – is an organization that promulgates consensus standards in the pipeline industry, among others.

[3] Hydrostatic testing involves the pressurization of water injected into the subject pipeline to establish integrity.

[4] National Transportation Safety Board (NTSB) Report 11-056, Materials Laboratory Factual Report, Table A-1.

[5] National Transportation Safety Board (NTSB) Report 11-057, Materials Laboratory Study Report, table on Page 2.

[6] Kiefner, J. F., Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, US DOT, Office of Pipeline Safety, Final Report No. 05-12R, (2007).

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