Cyclic Fatigue Analysis of Crack-Like Anomalies Using Hydrostatic and ILI Data

Tristan MacLeod
Kiefner and Associates, Inc.

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Abstract

Cyclic fatigue, particularly of crack-like anomalies, poses a significant risk to the integrity of pipelines. Manufacturing defects, notably in longitudinal seams of pipes produced before 1980, along with stress corrosion cracks (SCC) in the pipe body, are prone to expansion and potential failure during service due to pressure-cycle-induced fatigue. Under current U.S. pipeline integrity management regulations, natural gas pipelines in high-consequence areas (HCAs) and sections vulnerable to cyclic fatigue must undergo thorough assessments for crack growth and remaining service life.

Pipeline operators are advised to implement integrity assessments through hydrostatic testing or in-line inspection (ILI) with dependable crack detection tools to mitigate the risk of failure due to pressure-cycle-induced fatigue. The frequency of reassessment should be determined based on the size and growth rates of any potential defects that might persist following an initial hydrostatic test or ILI. Pressure cycles imposed on the pipeline could lead to the growth of barely surviving defects at a rate determined by the material's characteristics and environmental conditions. Using well-established principles, operators can predict the remaining lifespan of the pipeline. These methods enable operators to schedule reassessments proactively, thereby preventing potential failures.

This paper outlines a method for determining reassessment intervals, an approach refined over more than 30 years. Through meticulous analysis of existing data, it is possible to sidestep common errors and inaccuracies in predicting remaining pipeline life. We present five case studies highlighting the successes and difficulties in analyzing cyclic fatigue. This paper aims to demonstrate that, although the fundamental principles are well-established and broadly recognized, applying these principles to pipeline integrity management demands a comprehensive understanding of the specific pipeline under assessment.

Introduction

Fatigue cracking is a known threat to pipeline integrity. Failures due in whole or part to fatigue cracking have been observed in both liquid [1] and gas [2] pipelines. Most fatigue failures have occurred in liquid pipelines due to the difference in compressibility between liquid petroleum products and natural gas. Still, the natural gas pipeline failure in San Bruno in 2010 showed evidence of cyclic fatigue and, therefore, the possibility of fatigue growth on gas pipelines. Changes to 49 CFR 192 in 2020 [3] now require natural gas pipeline operators to perform pressure-cycle-fatigue analysis (PCFA) on natural gas pipelines susceptible to cyclic fatigue.

Background

Liquid petroleum and natural gas transmission pipeline operators pressurize their pipelines at various pressures, often between 400 and 1,800 psi. Pipeline pressures are initially determined by the maximum stress a pipe can withstand without yielding using Barlow's formula. This is then reduced by a safety margin (design factor) depending on the pipeline's proximity to populated and environmentally sensitive locations. [4]

Pipeline pressure fluctuates depending on several factors: demand, storage, compressor and pump constraints, safety requirements, network complexity, and maintenance activities. Furthermore, these

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pressure variations are much higher in liquid than in gas pipelines, mainly due to the incompressibility of liquid. Figure 1 features the operating pressure spectrum of a liquid product pipeline and a natural gas pipeline during the same period. The liquid pipeline experiences more severe pressure changes than the gas line, which is typical. This figure does not represent the pressure spectra of all gas and liquid pipelines. It merely demonstrates the distinct difference in magnitudes of pressure change between them over time, known as cycling. Thus, we can see why cyclic fatigue of cracks has historically caused more failures in liquid than gas lines.

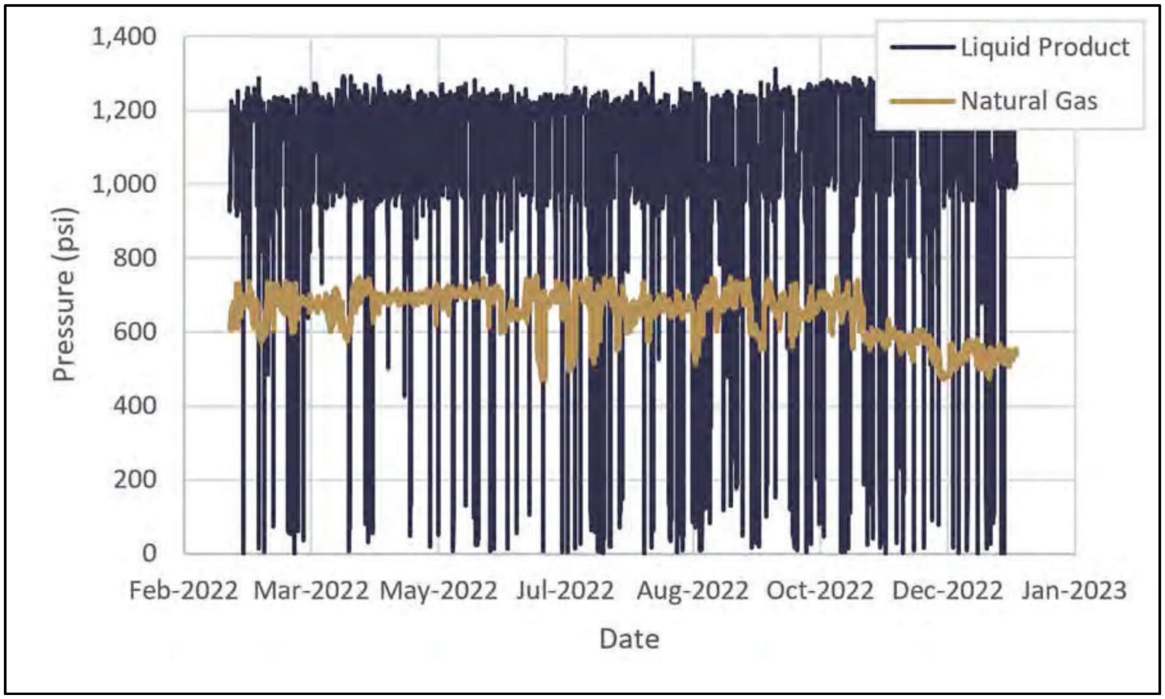

Figure 1. One Example of Liquid vs. Gas Pipeline Pressure Spectra

Pressure cycling is one of the two main ingredients for cyclic fatigue of crack-like defects. The other is the existence of the cracks themselves. These cracks often originate in axially oriented manufacturing or installation defects. Historically, these failures have often involved defects in or around the pipe's longitudinal seam (long seam) due to its orientation along the axis of the pipe. Pipes manufactured before 1980 may contain many more flaws due to less advanced steelmaking and joining methods and less advanced inspection methods at the pipe mill. Low-frequency electric-resistance-welded (ERW) and electric-flash-welded (EFW), as well as double-submerged-arc-welded (DSAW) pipe manufactured before 1980, may be much more susceptible to the existence of axially oriented defects compounded by the problem of lower material toughness. Modern pipelines without significant defects can survive hundreds of thousands of pressure cycles.[5] However, many flaws have been found in modern, post-1980 pipes, just not nearly as many as in pre-1980.

Operators may use either historical hydrostatic testing (hydrotest) data or in-line inspection (ILI) data to postulate a set of cracks that may be affected by fatigue growth. Using the hydrotest date and maximum held pressure, operators can calculate a collection of the worst possible cracks in the pipeline. However, a more precise approach is to use a validated and reliable ILI crack detection tool to obtain actual crack dimensions and the maximum crack size that may have evaded detection. By applying the cyclic stresses experienced by the pipeline to the worst cracks, operators can simulate fatigue crack growth and estimate the remaining fatigue life (time to failure).

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Pressure Data

Operators obtain the pressure of their pipelines using pressure sensors, often part of their supervisory control and data acquisition (SCADA) systems. The pressure data has two features: a timestamp and a pressure reading, in pounds per square inch (psi) in the USA or kilopascals (kPa) in Canada. To perform cyclic fatigue analysis, operators should use the most granular pressure data available, ideally measured every minute for the past year, to capture any seasonal changes. For liquid pipelines, using minute-by-minute data is critical for precisely analyzing their rapid pressure cycles. For gas pipelines, hourly data should suffice, but minute-by-minute is preferable, especially to rule out any possible erroneous sensor readings.

Operators should use rainflow-counting or similar techniques to classify the susceptibility of a line segment to cyclic fatigue.[6] Classification is not required for PCFA but is helpful to determine the aggressiveness of the pressure-cycling on a line segment. Operators must perform at least one type of cycle counting to generate a history of pressure changes to estimate crack growth. Cycles under 25 psi may be discarded since, in practice, they produce no change in stress intensity and, therefore, no crack growth. After rainflow-counting, operators may bin the pressure cycles based on their magnitude to classify the cycling aggressiveness. Research [7] has produced an annualized table of binned, rainflow-counted pressure cycles to quickly determine the aggressiveness of pressure cycling, shown in Table 1.

Table 1. Classifying Aggressiveness Based on Annual Pressure Cycles Binned in % SMYS

Range, % SMYS	Very Aggressive	Aggressive	Moderate	Light
65 to 72	20	10	2	0
55 to 65	40	20	4	0
45 to 55	100	50	10	0
35 to 45	500	250	50	50
25 to 35	1,000	500	100	100
20 to 25	2,000	1,000	200	200

Initial Crack Sizes – Historical Hydrostatic Testing Data

Ideally, the operator should use reliable ILI crack tool data to obtain the dimensions of axially oriented cracks in the pipeline. However, operators may use historical hydrostatic testing data to estimate the most significant cracks in the pipeline if such data is unavailable. First, the operator selects a range of crack depths that may exist, typically every 10% step from 10 to 90% of the wall thickness (WT), to create a set of nine cracks. For the pipeline strength and toughness properties, upper-bound values should be used to be conservative. A stronger and tougher pipe will allow more significant potential defects to survive the hydrotest. When toughness is unknown, 49 CFR 192.712 requires an upper-shelf Charpy V-notch (CVN) toughness of 120 ft-lbs for a PCFA based on hydrotest data. Using a suitable crack failure pressure calculation (Modified Ln-Sec, API 579 Level 2 Crack Assessment, etc.),[8] the operator determines the maximum length of each crack using the hydrotest pressure as the failure pressure. These cracks represent the most significant cracks that may have survived the hydrotest. This methodology is very conservative, as we assume that 70 to 90% deep

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cracks exist. This assumption will likely require reassessment every five years for aggressively cycled liquid lines. However, for pipes manufactured after 1980, operators may consider limiting the crack depth to 10 to 50% based on improved manufacturing and inspection standards at the pipe mill, allowing for longer reassessment intervals. Finally, operators should realize that ILI crack tool data may be needed to successfully perform PCFA on the most high-risk line segments.

Initial Crack Sizes – ILI Data

When an operator has reliable and validated ILI crack tool data for their pipeline, they may use it to establish the initial crack sizes for PCFA. Operators should obtain crack dimensions from the ILI pipe tally and then add the ILI tool manufacturer's specified tool tolerance to the anomalies' length and depth to be conservative. The manufacturer's threshold length and depth for detecting anomalies should also be modeled as a crack anomaly. Operators should use actual strength and toughness values for the pipeline properties wherever possible. SMYS or 5th percentile yield strength should be used when the precise strength has not been tested. 49 CFR 192.712 now requires the usage of very conservative toughness values for crack assessments of the long seam, with toughness values of 4 ft-lbs for lines with no history of reportable incidents due to cracking or 1 ft-lb for line segments with a history of reportable incidents due to cracking. Operators should use crack assessment methods capable of estimating failure pressure at low toughness values (such as API 579 Level 2) during PCFA when necessary.

Scaling Pressure Cycles Based on Location

API RP 1176 (2016) states:

> The segmentation of hydrostatic testing or anomalies identified through ILI can drive a need to determine the pressure spectra for points on a pipeline between pressure locations. (The following equation) can be used to determine the pressures at the location, provided the time stamps do match. Gathering pressure data based on pressure change can result in the upstream and downstream pressures having different time stamps. An algorithm should be used to interpolate between data points to facilitate the use of the equation when intermediate pressure data need to be calculated. Calculating location-specific pressure data is not necessary for gas pipelines due to the lack of appreciable change of a hydraulic gradient.

The equation below may be used to interpolate the discharge and suction pressure spectra. The interpolated spectra may then be rainflow-counted to calculate pressure cycles with a magnitude scaled based on location, elevation, specific gravity of the product, and the pipe diameter:

$$P_x = (P_1 + K \cdot h_1 - P_2 - R \cdot h_2)\left(\frac{1}{\frac{(L_x - L_1)\cdot D_2^5}{(L_2 - L_x)\cdot D_1^5} + 1}\right) - K(h_x - h_2) + P_2$$

Where,

P_x Intermediate pressure point between pressure sources

P_1	Upstream discharge pressure
P_2	Downstream suction pressure
R	SG·(0.433psi/ft) where SG = Specific Gravity of Product
L_1	Location of the upstream discharge station
L_2	Location of the downstream suction station
Lx	Location of point of analysis
h_1	Elevation of the upstream discharge station
h_2	Elevation of the downstream suction station
h_x	Elevation of point of analysis
D_1	Pipe diameter of the segment between L_1 and Lx
D_2	Pipe diameter of the segment between Lx and L_2

Crack Growth Equations

Fatigue crack growth may be modeled using Paris' law, shown below: [9]

$$\frac{da}{dN} = C(\Delta K)^n$$

Where,

$\frac{da}{dN}$	Crack depth (a) growth per loading cycle (N).
C	Crack growth constant dependent on material and environment.
n	Crack growth constant dependent on material and environment.
ΔK	Change in stress intensity.

C and n depend on the pipeline material and service environment. For conservative estimates in typical transmission pipeline environments, 8.61E-19 psi√in and 3.0 may be used, respectively.[10] Operators may use less conservative material constants if they have data to show that smaller constants are more representative of their service environment. The Newman-Raju [11] equation provides a method for calculating the change in stress intensity factor, K:

$$\Delta K = \Delta P \frac{D}{2t}\sqrt{\pi \frac{a}{Q}}F$$

Where,

$$Q = 1 + 1.464\left(\frac{a}{c}\right)^{1.65}$$

$$F = \left[M_1 + M_2\left(\frac{a}{t}\right)^2 + M_3\left(\frac{a}{t}\right)^4\right] f_\varphi G$$

$$M_1 = 1.13 - 0.09\left(\frac{a}{c}\right)$$

$$M_2 = -0.54 + \frac{0.89}{0.2 + \frac{a}{c}}$$

$$M_3 = 0.5 - \frac{1}{0.65 + \frac{a}{c}} + 14\left(1 - \frac{a}{c}\right)^{24}$$

$$G = 1 + \left[0.1 + 0.35\left(\frac{a}{t}\right)^2\right](1 - \sin\varphi)^2$$

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$$f_\varphi = \left[\left(\frac{a}{c}\right)^2 \cos\varphi^2 + \sin\varphi^2\right]^{\frac{1}{4}}$$

And,

ΔP	Change in pressure
D	Outside diameter
t	Wall thickness
a	Crack depth
$2c$	Crack length
φ	Surface angle (0° for length growth and 90° for depth growth)

Additional terms may be added to model bending stress, or a more simplified version of Newman-Raju may be used.[12] A threshold stress intensity factor should be implemented, ΔK_{th}, below which $\frac{da}{dN} = 0$. To apply this threshold, discard pressure changes less than or equal to 25 psi. Ideally, numerical methods should be used to solve Paris' law iteratively for each historical pressure cycle in the pressure history and then repeated until the crack grows to a failure state. Once this is complete, the remaining life is estimated based on the pressure cycles required for failure.

Remaining Life

PCFA includes calculating the crack's failure pressure after each iteration of cyclic growth to estimate the time to failure. Once the fatigue crack's failure pressure reaches a threshold, such as the pipeline's MAOP, the crack has reached the failure state, and the simulation is halted. The next step is to count the pressure cycles required to grow the crack from its initial to final critical condition, where the failure pressure has met MAOP. This is calculated by summing the time increment for each pressure cycle during the analysis. Limiting the calculations to a maximum remaining life, such as 100 years, will be helpful to avoid excessive computation time. Finally, a safety factor of two is applied to the remaining life to determine a reasonable reassessment interval. Alternatively, a safety factor may be applied to the failure pressure threshold where appropriate.

Case Studies

The author has performed numerous PCFAs for gas and liquid pipeline operators and presents five case studies. These case studies represent typical PCFA scenarios and results, including successes, challenges, and solutions.

Case Study 1

Operator A has an extensive natural gas transmission pipeline network in the USA. PCFA was performed on over 50 different line segments in the network. The most recent year of pressure data (discharge and suction) was used. Historical hydrostatic test dates and pressures were used to establish the most significant cracks that may have plausibly existed. The results of the PCFA were that 100% of the line segments had an estimated remaining fatigue life of over 100 years due to their low pressure cycling and relatively low MAOP. This is a common, but not guaranteed, result for many gas pipelines. These results show that operators can often use hydrotest data to quickly and efficiently perform PCFA on pipelines with low cycling aggressiveness.

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Case Study 2

Similarly, Operator B has an extensive natural gas pipeline network in the USA. PCFA was performed on their entire network of pipeline segments. Their data contained over 60,000 pipeline segments, with properties such as name, chainage, long seam type, installation date, hydrotest date and pressure, strength, etc. High-risk line segments (in HCAs and areas covered by 49 CFR 192.710) were separated from lower-risk segments to form two separate reports. Excel macros were used to quickly process and separate the data by HCA, long seam type, manufacturing date, yield strength, etc. Using another Excel workbook, the most aggressive pressure data was used to perform PCFA on many line segments simultaneously. About 30 line segments had a short estimated remaining life when using the most aggressive pressure data. For these line segments, PCFA was performed using the actual pressure as a more fine-tuned analysis method. These lines all had an estimated remaining fatigue life of just over ten years. This is a good result for the operator, but they may need to run ILI crack tools in the near future to support future PCFAs.

Case Study 3

Operator C has an extensive liquid petroleum network in the USA. PCFA was performed on six of their line segments using ILI crack tool data. PCFA using historical hydrotest data was not feasible for this operator due to the aggressive cycling of their liquid lines. The PCFA simulated fatigue growth of the crack-like ILI defects using the most recent 12 months of pressure data. For 95% of the crack-like defects, the PCFA resulted in an estimated remaining fatigue life of over ten years (reassessment interval of over five years). However, for the remaining 5%, the estimated remaining fatigue life was less than ten years, and the operator may need to investigate and remediate these defects. This was overall a very positive result for the operator and shows how ILI crack tools are often crucial for liquid operators to support PCFA.

Case Study 4

Operator D has an extensive network of storage and transmission natural gas pipelines in the USA. PCFA was performed on all their lines in HCAs using the most recent 12 months of pressure data. The most recent hydrotest date and pressure were used to estimate the most significant cracks possible in the long seam. The result: 97% of the operator's natural gas lines had reassessment intervals of over five years. However, the remaining 3% (two line segments) had an estimated remaining fatigue life of 0 years, caused by one primary factor: no known hydrotest records for those lines. With no records, conservative assumptions were made about the commissioning hydrotest pressure (lower being a more conservative guess). When the hydrotest pressure is not sufficiently higher than the MAOP, the simulated cracks will more quickly reach the failure state. Overall, this project was very successful for the operator despite two lines that lacked hydrotest records. The operator may remediate this situation by locating the documents, or they may need to perform a hydrotest or ILI. This highlights the importance of operators keeping complete records for the life of the pipeline.

Case Study 5

Operator E owns a liquid petroleum pipeline manufactured in the 1940s with a low-frequency (LF) ERW long seam, which has a relatively high risk for crack-like defects compared to modern pipe. The

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operator has successfully managed the risk of this pipeline by running ultrasonic ILI crack tools for the entire pipeline length within the past five years. They have also completed a dig program based on the data from the ILI tool and remediated numerous crack-like anomalies. PCFA was performed on the remaining crack-like ILI defects with an estimated remaining fatigue life of over 20 years. This successful result is mainly due to the operator's proactive integrity program of running ILI crack tools and then validating and remediating high-risk suspected defects. Without this program, it's unlikely that the PCFA could've estimated an adequate remaining fatigue life of this pipeline.

Recommendations and Considerations

Based on these case studies and others, some recommendations and considerations can be made to operators regarding performing PCFAs:

1. Assume that every line segment may require PCFA until proven otherwise.
2. Record and store easily accessible pressure data (at least the past year) for all line segments recorded at both the discharge and suction, preferably recorded every minute (every hour is adequate for gas lines).
3. Classify the pressure cycling aggressiveness of all line segments using rainflow-counting, benchmark cycle analysis, and other similar techniques.
4. Pre-1980 pipe with unknown, ERW, EFW, or DSAW pipe has the highest risk of cyclic fatigue failure—but modern pipe can fail too!
5. Historical hydrotest data may often be used to perform very efficient PCFAs on low-risk and modern pipelines.
6. Postulated defects should be modeled considering the manufacturing and inspection standards for the pipe's construction era.
7. Understand that ILI crack tool data (or a recent hydrotest) may be required to perform a suitable PCFA on high-risk line segments.
8. Successfully running an ILI crack tool on natural gas pipelines remains a potential roadblock to performing successful PCFAs on these lines, especially those with aggressive cycling.
9. Pipelines that lack traceable, verifiable, and complete (TVC) records may carry the most significant risk.

Conclusion

Pipeline operators should perform PCFA on lines susceptible to cyclic fatigue to ensure integrity and regulatory compliance. To prepare for an internal or 3rd party PCFA, record and store pressure data collected from the discharge and suction of the pipeline. The PCFA process itself starts with processing the pressure data using rainflow-counting. Then, determine the most significant possible cracks in the pipeline. Use reliable, validated ILI crack tool data to determine the most plausible crack dimensions. Without ILI crack data, historical hydrostatic test data may be used to choose the most significant cracks. Operators using hydrotest data must remember that aggressively operated pipelines, predominantly liquid lines, will likely require recent hydrostatic tests to obtain reassessment intervals longer than five years. This is due to the very conservative nature of PCFA using hydrotest data. Lastly, operators should continue seeking the most reliable crack detection technologies to perform the most realistic PCFA of their pipelines.

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