Crack Management

• Cracks are a growing concern for PHMSA and pipeline operators. Managing cracks is high on PHMSA’s list as it considers potential revisions to its regulations.

• As a consequence, pipeline operators can expect new and stronger emphasis on their own crack management plans, which should include steps to determine which lines are crack susceptible as well as to detect and size possible cracks, analyze them, make repair decisions, and so on.

• This talk will cover crack management for seam-weld defects and stress corrosion cracking (SCC).
Outline

- Notices of Proposed Rule Making (NPRMs) for Hazardous Liquid Pipelines (2015) and Gas Pipelines (2016)
- Stress Corrosion Crack Management
- Seam-Weld Crack Management
- Wrap-up

Current Rulemakings in Process

- Hazardous Liquid NPRM
- Gas Transmission NPRM
- Excess Flow Valve NPRM
- Plastic Pipe NPRM
- Operator Qualification and Cost Recovery NPRM
- Rupture Detection and Automatic shutoff Valve NPRM
- Standards Update
- Excavation Damage Final Rule
- Miscellaneous Final Rule

Today’s Regulatory Climate

- OPS is under fire from Congress, the NTSB, the public, and others
  - It is struggling to meet demands placed on it, many of which were the result of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016
- Rulemaking, in general, has become more difficult
  - OPS is being pushed to be more independent of the pipeline industry
  - The influence industry has on regulations has decreased
  - The time required for rule making has increased to the point where it now takes 2 to 6 years, or more, to introduce substantive regulatory changes
- OPS increasingly uses non-regulatory means to establish and enforce safety requirements
  - Advisory Bulletins, FAQs, and other non-regulatory actions
  - The potential exists for introduction of new requirements through the court system
Notices of Proposed Rulemaking

- PHMSA published two important notices of proposed rulemaking in 2015/2016 with implications for hazardous liquid and natural gas pipelines.
- The liquid NPRM introduced several new concepts related to crack management. The gas NPRM greatly expanded the concepts.
- We expect the gas concepts to be eventually incorporated into the liquid rulemaking or advisory bulletins.

NPRM on Safety of Hazardous Liquid Pipelines

- On October 13, 2015, PHMSA issued a NPRM proposing significant changes to 49 CFR 195; related to cracks, PHMSA proposed:
  - New definition of *significant stress corrosion cracking*, which is listed as an immediate repair condition.
  - Similar requirements for *selective seam weld corrosion*.
  - Adoption of NACE standard for SCC Direct Assessment.
New Definition

- In the liquid NPRM, PHMSA proposed to add a new definition of "Significant Stress Corrosion Cracking." The new definition provides criteria for determining when a probable crack defect in a pipeline segment must be excavated and repaired.
  - **Significant stress corrosion cracking** means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.
- This definition has its root in the Canadian Energy Pipeline Association’s Stress Corrosion Cracking Recommended Practices, first edition.

CEPA SCC Recommended Practices

- Problem 1: CEPA rescinded its definition of significant SCC in the second and third editions of its recommended practice because the term was misleading
  - CEPA intended the definition to identify noteworthy cracks, meaning cracks that could become a threat to the pipeline in the future
  - CEPA did not intend the definition to identify cracks that were an immediate concern
- Problem 2: Most, if not all, SCC identified in an in-line inspection will be classified as significant (potential immediate repair conditions)
NPRM for Safety of Gas Transmission and Gathering Pipelines

- March 17, 2016, PHMSA issued a NPRM proposing significant changes to 49 CFR 191 and 192.
  - 549 page document is one of the largest NPRMs ever issued by PHMSA
  - Most extensive changes since the regulations were first issued
  - Strong emphasis on crack management
  - PHMSA estimates the annual compliance cost at roughly $600 million over 15 years (approximately $40 million per year)

Strong Emphasis on Crack Management

- The natural gas NPRM contains the same definition of significant stress corrosion cracking as the proposed liquid rule
  - The gas NPRM also emphasizes seam-weld crack management
  - Liquid the hazardous liquid NPRM, selective seam corrosion is a threat to be managed on early generation pipe

- The gas NPRM provides detailed requirements on analyzing crack severity, including selection of material properties
Gas NPRM: Fracture Mechanics Requirements

- Fracture mechanics modeling for failure stress and crack growth analysis. If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline,
- ...the operator must perform fracture mechanics modeling for failure stress pressure and crack growth analysis to determine the remaining life of the pipeline at the maximum allowable operating pressure based on the applicable test pressures
- ...including the remaining crack flaw size ... any pipe failure or leak mechanisms identified ... pipe characteristics, material toughness, failure mechanism ... (ductile and brittle or both), location and type of defect, operating environment, and operating conditions including pressure cycling.

Steps in a Crack-Management Program

- Identify susceptible segments
- Perform a baseline crack-detection assessment
- Evaluate, repair, and remediate as needed
- Establish reassessment intervals
**Identifying Susceptible Pipelines**

- Identifying which pipelines are susceptible to cracking is the first step.
- Ruling out a cracking threat can be problematic.
  - PHMSA does not accept “we haven’t seen cracking” as a rationale for not conducting an assessment
  - A number of pipeline operators are finding that simple rules of thumb on what is susceptible can be non-conservative
- The following slides cover determining susceptibility to SCC and to seam-weld defects

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**SCC Susceptibility Screening**

- SCC susceptibility ratings are generally based on:
  - Types of external coating on the pipe, girth welds, branches, appurtenances, and repairs
  - Maximum operating stress levels relative to SMYS
  - Pipeline age
  - Maximum operating temperature (high pH SCC only)
  - Distance from upstream station
  - Whether SCC had been previously detected on the segment
ASME B31.8S SCC Criteria

- Possible threat of near-neutral pH SCC if
  - Coating system other than FBE or liquid epoxy
  - Operating stress >60% SMYS
  - Age of pipeline > 10 years

- Possible threat of high pH SCC if
  - Coating system other than FBE or liquid epoxy
  - Operating stress >60% SMYS
  - Age of pipeline > 10 years
  - Operating temperature > 100 deg F
  - Distance from compressor station discharge ≤20 miles

Susceptibility Factors

- External coating type
  - Industry experience shows that a higher number of SCC occurrences have been documented beneath certain coating systems.
  - For high pH SCC, cracking is most common in coal tar coated pipe (70% of the failures).
  - For near neutral pH SCC, cracking is most common under tape coated and asphalt coated lines.
  - There is one documented occurrence of SCC beneath FBE
  - There are no occurrences under extruded polyethylene (EP), such as "Yellow Jacket"
Susceptibility Factors

- Operating Stress
  - There is no recognized threshold stress below which SCC does not occur. However, research to date suggest high pH SCC initiation is much more likely at high stress levels (e.g., above 60% SMYS); near neutral pH SCC occurs near stress risers even when the nominal operating stress is lower
  - Ruptures are more likely at higher stresses
  - Local stress risers, such as dents and bends, are important for near neutral pH SCC
- Age
  - Age plays a factor in allowing time for coatings to degrade and susceptible electrochemical environments to form under damaged coatings. Usually, pipe under 10 years old is considered not susceptible to SCC.

Susceptibility Factors

- Operating Temperature
  - Segments that operate at elevated temperatures have a higher likelihood of coating damage and high pH SCC. Coating damage is required for SCC to occur.
  - Locations of elevated temperature are typically located within close proximity to the discharge side of a station or of refinery outputs. Exceptions exist.
  - There have been limited numbers of cases where high pH SCC did not follow the higher-temperature guidelines
- Distance from Upstream Pump or Compressor Station
  - Most high-pH SCC has been found in the first 20 miles of pipeline downstream of a compressor station.
  - Laboratory data and field experience indicate that near neutral-pH SCC is less temperature dependent and does not appear to follow a similar pattern.
Bottom Line on SCC Susceptibility

- Pipeline coating type is the strongest factor – learn which coating types are most SCC susceptible
- Recognize lines that operate below 60% SMYS can be susceptible to SCC (especially near-neutral pH SCC)
  - Consequences associated with lower stress lines can be less (leak versus rupture), decreasing the overall risk
  - Consider both current and prior operating stresses, as well as local stress risers, such as dents, welds, and bends
- For high pH SCC, consider current and historic operating temperatures
- For now, rules of thumb for age and distance to compressor station (for high pH SCC) appear valid
Seam Weld Crack Susceptibility

- Seam weld susceptibility depends on the pipe vintage, source, seam weld type, and loading (pressure cycling)
- Steps in assessing susceptibility
  - Determine pipe vintage and seam-weld type
  - Review historic data on pipe mill and pipe type
  - Assess susceptibility

Determine Pipe Vintage and Seam-Weld Type

- Any pipe that could be pre-1979 should be considered a candidate for seam-weld management
  - Some pipe made after 1979 has also experienced seam-weld failures
- High- and low-frequency ERW should be considered
- Double submerged arc welded pipe is generally not included (except for transportation fatigue)
What If You Don’t Know The Seam Type?

<table>
<thead>
<tr>
<th>Process</th>
<th>Dates</th>
<th>Common Diameters (inch)</th>
<th>Max Length (feet)</th>
<th>Unique Identifying Characteristic(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Furnace Butt Weld (FBW)</td>
<td>1832-1954</td>
<td>1/8 – 3</td>
<td>20</td>
<td>No visible weld, relatively short joint length</td>
</tr>
<tr>
<td>Continuous Butt Weld (CBW)</td>
<td>1923-Current</td>
<td>1/8 – 1 1/2</td>
<td>40</td>
<td>Uniform wall thickness with no visible weld</td>
</tr>
<tr>
<td>Lap Weld</td>
<td>1887-1962</td>
<td>1 1/4 – 30</td>
<td>22 – 26</td>
<td>Waffle-like pattern over the weld seam</td>
</tr>
<tr>
<td>Hammer Weld</td>
<td>1917-1921</td>
<td>20 – 96</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>Electric Resistance Welded (ERW)</td>
<td>1928-Current</td>
<td>1 1/2 – 24</td>
<td>80</td>
<td>Occasional &quot;burn tool marks&quot; near the weld zone</td>
</tr>
<tr>
<td>Flash weld (EFW)</td>
<td>1930-1972</td>
<td>8 5/8 – 36</td>
<td>40</td>
<td>Square weld bead shape on the ID and OD</td>
</tr>
<tr>
<td>Single Sided Arc Weld</td>
<td>1925-1952</td>
<td>To 96</td>
<td>30</td>
<td>Elliptical weld bead on the inside diameter</td>
</tr>
<tr>
<td>Double Submerged-Arc Weld (DSAW)</td>
<td>1946-Current</td>
<td>16 – 48</td>
<td>40</td>
<td>Elliptical weld bead on the inside and outside diameters</td>
</tr>
<tr>
<td>Seamless</td>
<td>1890-1938</td>
<td>To 6</td>
<td>40</td>
<td>Surface roughness, and helical variation in wall thickness</td>
</tr>
<tr>
<td>Spiral Weld</td>
<td>1948-Current</td>
<td>To 56</td>
<td>40</td>
<td>Helical weld seam</td>
</tr>
</tbody>
</table>

Historical Note

- Historically, seam welds have been made by several forms of butt welding, lap welding, hammer welding, electric resistance welding, flash welding, single-sided submerged arc welding, double submerged arc welding, and others
  - While many pipe manufacturers used (or use) most of the weld processes, "problem pipe" is typically associated with some of these processes and a subset of pipe manufacturers
  - For those manufacturers, not all individual pipe mills produced problem pipe, nor did they produce problem pipe at all time periods
  - If you know who made the pipe and when, you may be able to rule in or out certain problems
Manufacturers with Historic Problems

<table>
<thead>
<tr>
<th>Evaluation Criteria</th>
<th>Years</th>
<th>Most Frequently Reported Manufacturers</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low frequency ERW</td>
<td>Pre 1971</td>
<td>Republic, Youngstown</td>
<td>Acero del Pacifica, Jones &amp; Laughlin, Kaiser, &amp; Lone Star also have higher incident rates than others</td>
</tr>
<tr>
<td>High frequency ERW</td>
<td>Pre 1980</td>
<td>Stupp and U.S. Steel</td>
<td>American Steel Pipe, Kaiser, Jones &amp; Laughlin, Lone Star also have higher incident rates</td>
</tr>
<tr>
<td>Flash weld</td>
<td>All</td>
<td>A.O. Smith</td>
<td>Houston factory may be less prone to problems</td>
</tr>
</tbody>
</table>

The INGAA report 'Integrity Characteristics of Vintage Pipelines" contains additional examples.

Assess Cyclic Loading

- The most common method of cyclic loading for early generation pipe is using the Michael Baker report TT05.
Assess Cyclic Loading

- The process starts by identifying pre 1970 LF and DC ERW pipe or lap welded pipe as potentially susceptible
- Lap welded pipe with an in-service release due to seam weld problems requires a baseline assessment

NPRM Requirements on Pre 1970 Low Frequency & DC ERW Pipe

- Any pipe that has experienced a seam-related that is attributed to fatigue or grooving (preferential) corrosion is considered susceptible
  - Releases due to lack of fusion and without evidence of fatigue do not automatically require a seam assessment
  - If you don’t know whether a release was due to fatigue or grooving corrosion, you don’t have to assume it was!
- Lines that have not been hydrotested to at least 1.25 MAOP/MOP are considered seam susceptible
- Lines that have been hydrotested to at least 1.25 MAOP/MOP are considered susceptible if they experienced a test failure attributed to fatigue or grooving corrosion and they are bare, poorly coated, or poorly protected by cathodic protection
Pre 1970 Low Frequency and DC ERW Pipe

- Pre 1970 ERW generally requires a more detailed assessment if it operates above 30% SMYS
- Pre 1970 ERW that operates below 30% SMYS is considered not susceptible to seam failure

Be aware that some post 1970 pipe has also had seam problems

Bottom Line on Seam Weld Crack Susceptibility

- Pipeline age is a good first discriminator, but recognize some post 1970 pipe (and some high frequency ERW) can also have problems
- When possible, determine the pipe mill
  - Some pipe mills have a history of producing problem pipe
- Evaluate your operating pressure history
  - Aggressive and Very Aggressive pressure loading is problematic
Steps in a Crack-Management Program

- Identify susceptible segments
- Perform a baseline crack-detection assessment
- Evaluate, repair, and remediate as needed
- Establish reassessment intervals

Conducting an Integrity Assessment

- Hydrotesting, in-line inspection, and SCC direct assessment are options
  - Hydrotesting, per the NPRM proposed regulations, requires a spike test:
    - “The pressure test method requires performance of a spike pressure test ... if the pipeline includes legacy pipe or ... legacy construction techniques or if the pipeline has experienced a reportable in-service incident ... due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking.”
    - “the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS”
    - Many early generation seam welds will not withstand a pressure test to 105% SMYS
In-line Inspection – Gas Pipelines

- For gas lines, in-line inspection is generally limited to circumferential MFL or EMATs
  - Circumferential MFL tools should be sensitive to selective seam weld corrosion and open cracks
  - EMATs is a relatively new technology; it is proving useful for SCC, but its success rate with seam-weld flaws is not well documented

In-line Inspection – Liquid Pipelines

- For liquid lines, in-line inspection options include ultrasonic crack detection systems
  - UTCD tools are also relatively new
  - Experience shows these tools are improving with regard to detection of seam defects; sizing and discrimination between, for example, hook cracks and lack of fusion, is still a concern
Gas NPRM Requirements

- "The ... assessments and the reassessments ... must be performed using one or more of the following methods:
  - "Internal inspection tool or tools capable of detecting ... material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks) ..."
  - "At a minimum, the operator must conduct an assessment using ... either an electromagnetic acoustic transducer (EMAT) or ultrasonic testing (UT) tool”
  - "All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated”

Gas NPRM Requirements on In-line Inspection

- "When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment ...

192.493 requires compliance with the requirements and recommendations of
- API Standard 1163, In-line Inspection Systems Qualification Standard
- ASNT IN-LINE INSPECTION-PQ-2005 In-line Inspection Personnel Qualification and Certification
- NACE SP0102-2010 In-line Inspection of Pipelines

- "In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.”
**Significant Seam Cracking**

- The gas NPRM identifies *significant seam cracking*
  - Significant seam cracking means cracks or crack-like flaws in the longitudinal seam or heat affected zone of a seam weld where the deepest crack is greater than or equal to 10% of wall thickness or the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a failure pressure less than or equal to 110% of SMYS, as determined in accordance with fracture mechanics failure pressure evaluation methods (§§192.624(c) and (d)) for the failure mode using conservative Charpy energy values of the crack-related conditions.

- Both the hazardous liquid and gas NPRMs identify any indication of selective seam weld corrosion as an immediate repair condition

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**SCC Direct Assessment**

- “SCCDA is not as effective, and does not provide an equivalent understanding of pipe conditions with respect to SCC defects, as ILI or hydrostatic pressure testing”
  - “PHMSA has concluded the quality and consistency of SCCDA conducted under IM requirements would be improved by requiring the use of NACE SP0204-2008”
  - “PHMSA proposes to revise the requirements ... for direct assessment to allow use of this method only if a line is not capable of inspection by internal inspection tools”
Bottom Line on Integrity Assessments

- Hydrotesting requirements are becoming more stringent and must typically include a spike test to 150% MAOP or 105% SMYS, whichever is less
  - The spike test requirements could be problematic for early generation seam welds
- ILI options may be primarily limited to ultrasonic and EMATs (circumferential MFL?)
- SCCDA may only be allowed when ILI is not feasible

Steps in a Crack-Management Program

- Identify susceptible segments
- Perform a baseline crack-detection assessment
- Evaluate, repair, and remediate as needed
- Establish reassessment intervals
Fracture Mechanics Modelling

- Fracture mechanics modelling is being required for failure stress and crack growth analysis (remaining lives)
  - Pipe susceptible to cracks or crack-like defects
  - Fatigue analysis techniques
  - Analyze microstructure (ductile, brittle, or both), location and type of defect, operating conditions/pressure cycling
  - Reevaluation before 50% of the remaining life has been expended (but within 7 years)

NPRM Requirements on Field Examination of Defects

- “… operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches)”
- “In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards … confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated”
- “The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations”
NPRM Requirements on Engineering Critical Assessments (ECAs)

- "An ECA is an analytical procedure, based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections"
  - “The ECA must assess: threats; loadings and operational circumstances relevant to those threats including along the right-of-way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; initial and final defect size relevance”
  - “The ECA must quantify the coupled effects of any defect in the pipeline”
  - The results of an ECA must be “reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics”

Engineering Critical Assessments (ECAs)

- The ECA method has the potential to evolve into a method that verifies pipeline integrity more cost-effectively than pressure testing, but
  
  The ECA methodology is highly technical, highly complex, requires support from highly qualified SMEs, and has never been deployed as contemplated by the proposed rule
NPRM Requirements on How to Analyze Cracks

- The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each defect.
- The ECA must use the techniques and procedures in Battelle Final Reports ... or other technically proven methods including but not limited to API RP 579-1/Level II or Level III, CorLAS™, or PAFFC.

NPRM Requirements on Defect Sizes and Material Properties

- The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling).
- If actual material toughness is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must determine a Charpy v-notch toughness based upon the material documentation program ... or use conservative values ...
  as follows: body toughness \( \leq 5.0 \text{ ft-lb} \) and seam toughness \( \leq 1 \text{ ft-lb} \).
Bottom Line on Evaluation, Repair, and Remediation

- Engineering critical assessments analyses are being required
  - ECAs are highly technical, highly complex, requires support from highly qualified SMEs, and have never been deployed as contemplated by the proposed rule
- Results must be reviewed and/or approved by a fracture mechanics SME
- Minimum material properties are specified – these tend to be quite conservative

Steps in a Crack-Management Program

- Identify susceptible segments
- Perform a baseline crack-detection assessment
- Evaluate, repair, and remediate as needed
- Establish reassessment intervals
Establish Re-Assessment Intervals

- Fatigue life calculations are being required to calculate the time for an initial flaw to grow to critical at the operating condition and based on rainflow cycle counted pressure data
  - API 579 can be used to determine the appropriate Paris Law coefficient and exponent for the calculations
  - The most difficult part of this type of analysis is determining the initial flaw size for the calculations

- For fatigue, reassessment intervals can be based on the Paris Law approach
  - With Paris Law, a safety factor on total life between 2 and 5 is typically used
  - Other technically appropriate engineering methodology may be used provided they are “validated by a subject matter expert in metallurgy and fracture mechanics to give conservative predictions of flaw growth and remaining life”

What About Remaining Lives for SCC?

- The NPRM says “When assessing other degradation processes, the analysis must be performed using recognized rate equations whose applicability and validity is demonstrated for the case being evaluated”
Requirements on Re-Assessment Intervals Following Hydrotests

- "For ... critical flaw size, conservative remaining life analysis must assess the smallest critical sizes and use a lower-bound toughness. For cases dealing with ... defect sizes that would survive a hydro test pressure, conservative remaining life analysis ... must ... use upper-bound values of material strength and toughness.
  - For hydrotests: “use a ... Charpy upper-shelf energy level of 120 ft-lb and a flow stress equal to the minimum specified ultimate tensile strength of the base pipe material”
  - “For critical flaw sizes: use ... SMYS and SMTS ... and "Charpy toughness valves lower than or equal to: 5.0 ft-lb for body cracks; 1.0 ft-lb for ERW seam bond line defects such as cold weld, lack of fusion, and selective seam weld corrosion defects”
- "The analysis must include a sensitivity analysis to determine conservative estimates of time to failure for cracks”

Requirements on Re-Assessment Intervals Following an ILI

- Initial flaw sizes are to be based on the reported flaw depth and length after accounting for tool error
  - A common approach is to take the upper depth value for depths that are reported in a bin or adding the tolerance given in the Performance Specification for depths reported as an absolute or relative value
Special Considerations for ERW and Early Generation Pipe

- PHMSA has expressed concern about some ERW pipe exhibiting brittle behavior, where fracture occurs at much lower stress intensity factors than seen in "typical" ERW
  - In our experience, this is most likely when
    - The pipe seam weld did not receive proper heat treatment (annealing) during fabrication and the coating on the weld has deteriorated
    - Selective seam corrosion is encountered
- PHMSA says "Appropriate fracture mechanics modeling for failure stress pressures in the brittle failure mode is the Raju/Newman Model"
  - We do not recommend the use of CorLASTM for pipe in these categories!

NPRM Requirements on Remaining Lives

- "If the predicted remaining life ... is 5 years or less, then the operator must perform a pressure test ... or reduce the maximum allowable operating pressure of the pipeline ... within 1-year of analysis
- "The operator must re-evaluate the remaining life ... before 50% of the remaining life ... has expired, but within 15 years.
  - "The operator must determine ... if further pressure tests ... are required at that time.
  - "The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated ... has expired.
- "If the analysis results show that a 50% remaining life reduction does not give a sufficient safety factor ... then a more conservative remaining life safety factor must be used"
Bottom Line on Re-Assessment Intervals

- Remaining life analyses are being required, from which the reassessment interval can be based
- Results must be reviewed and/or approved by SMEs in both metallurgy and fracture mechanics
- Special requirements are proposed when dealing with short predicted remaining lives

Summary and Wrap Up
Steps in a Crack-Management Program

- Identify susceptible segments
- Perform a baseline crack-detection assessment
- Evaluate, repair, and remediate as needed
- Establish reassessment intervals

Recap: Steps in a Crack-Management Program

- Identify susceptible segments
  - For SCC, pipeline coating type is the strongest factor – learn which coating types are most SCC susceptible – and recognize lines that operate below 60% SMYS can be susceptible to SCC (especially near-neutral pH SCC)
  - For seam susceptibility, pipeline age is a good first discriminator, but recognize some post 1970 pipe (and some high frequency ERW) can also have problems
- Perform a baseline crack-detection assessment
  - Hydrotecting requirements are becoming more stringent and must typically include a spike test to 150% MAOP or 105% SMYS, whichever is less
  - ILI options may be primarily limited to ultrasonic and EMATs
  - SCCDA may only be allowed when ILI is not feasible
Recap: Steps in a Crack-Management Program (Continued)

- Evaluate, repair, and remediate as needed
  - Engineering critical assessments analyses are being required
  - Results must be reviewed and/or approved by a fracture mechanics SME
- Establish reassessment intervals
  - Remaining life analyses are being required
  - Results must be reviewed and/or approved by SMEs in metallurgy and fracture mechanics
- Continually reassess

Thank you!

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