

Transmission Integrity Management Programs (TIMP)



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TIMP Intrastate Cycle

- Comprehensive every 4 years (plan & records)
 - 2014-2015
 - ~ 2018-2019
 - ~ Will eventually become risk based frequency
- Field inspections annually (based on activity)



TIMP Observations

- TIMP programs have matured into full-fledged programs.
- Operators transitioning towards in-line inspections when possible.
- Reassessments producing better data than initial assessments.
- Understanding of pipeline's "health" increasing.



SCC Assessment

- *§192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?...*
 - (b)(2) Assessment method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.*
- Long story short... refer to ASME B31.8S–2004...



SCC Assessment

...But ASME B31.8S-2004 is obsolete!

- *ASME B31.8S-2004: 6.2.2 Crack Detection Tools for the Stress Corrosion Cracking Threat.*

For this threat, the following tools can be used. Their effectiveness is limited by the technology the tool employs.

(a) Ultrasonic Shear Wave Tool.

*(b) Transverse Flux Tool. **

- What about EMAT tools?



SCC Assessment

- *ASME B31.8S-2004: 6.3.1 Time-Dependent Threats. Pressure testing is appropriate for use when addressing time-dependent threats. Time-dependent threats are external corrosion, internal corrosion, stress corrosion cracking, and other environmentally assisted corrosion mechanisms.*
- Very few natural gas operators are utilizing pressure tests as a form of assessment due to the inherent problems associated with taking a line out of service.



SCC Assessment

- *ASME B31.8S-2004: A3.1 Scope: Paragraph A3 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for high pH type stress corrosion cracking (SCC) of gas line pipe (see Fig. A3). Near neutral type SCC similarly would require an inspection and alternative mitigation plan.*
- This is the only mention of near-neutral SCC in ASME B31.8S-2004.



SCC Assessment

- *ASME B31.8S-2004: A3.3 Criteria and Risk Assessment: Each segment should be assessed for risk for the possible threat of SCC if all of the following criteria are present:*
 - (a) *operating stress > 60% SMYS*
 - (b) *operating temperature > 100°F*
 - (c) *distance from compressor station ≤ 20 miles*
 - (d) *age ≥ 10 years*
 - (e) *all corrosion coating systems other than fusion-bonded epoxy (FBE)*
- **What about near-neutral SCC? Eliminate b and c.**



SCC Assessment

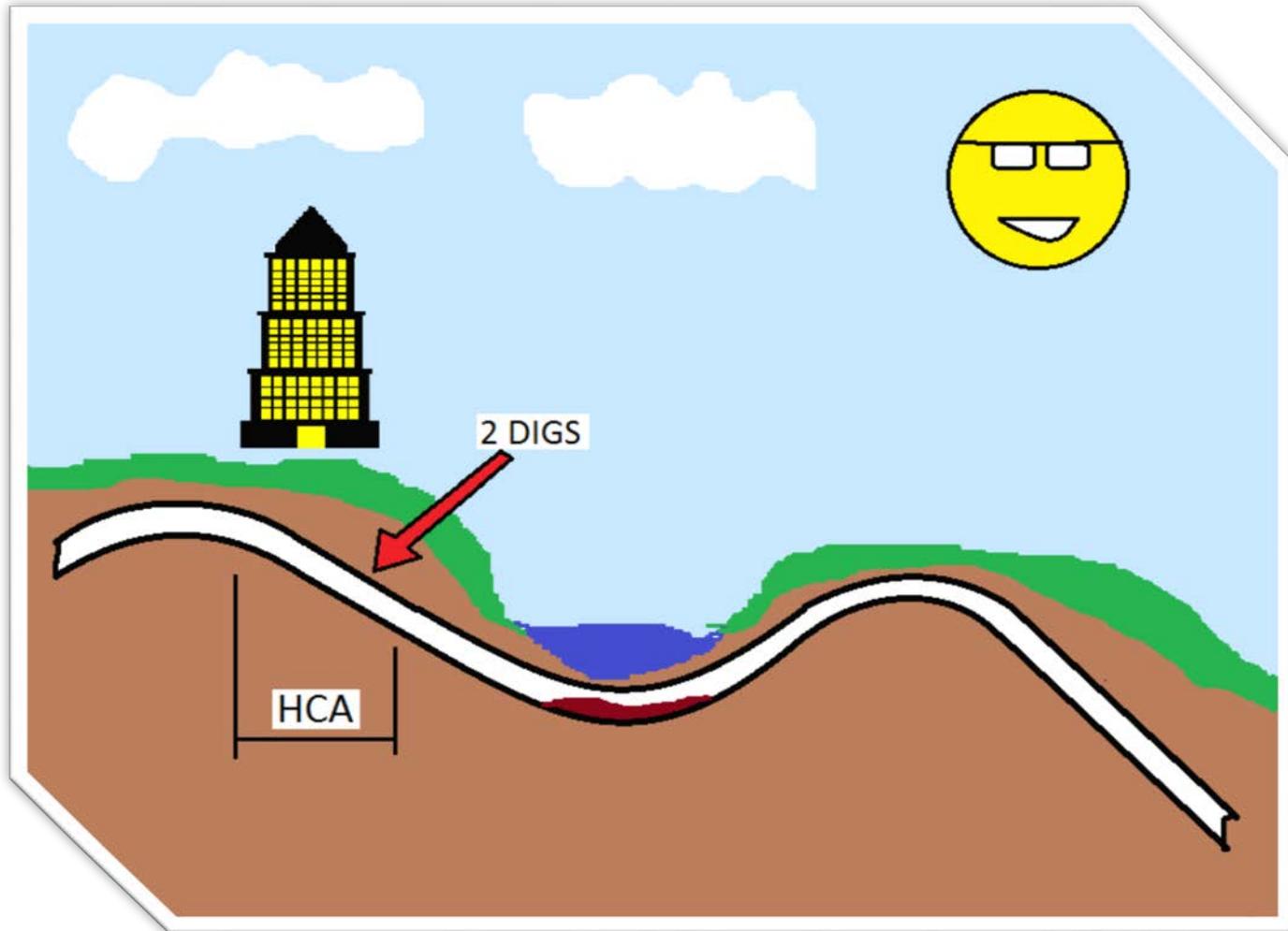
- Encouraging operators to use many of the newer standards, papers, and research to address SCC.
- Such resources include:
 - ASME B31.8S – 2010/2012/2014
 - NACE SP0204-2008
 - Numerous Industry White Papers
- But none of these are incorporated into 49 CFR Part 192!



Internal Corrosion Direct Assessment

- 49 CFR 192.927 provides the requirements that natural gas operators must adhere to regarding ICDA if using direct assessment technologies on their pipelines as their means of assessment.
- One of the requirements is that each operator excavate at least two locations in an ICDA region; one of the locations must be the low point near the beginning of the region and another further downstream near the end of the region.
- However, there are certain issues associated with the practicality of these excavations, particularly if there is not a low point within a covered segment.

Internal Corrosion Direct Assessment





Internal Corrosion Direct Assessment

- Many operators using NACE SP0206 to comply with the requirements in 49 CFR 192.927. However, this is not without its complications (but better guidance than the code!)
- *4.2.2.1 For the DG-ICDA flow calculations, the operator shall use the highest critical inclination angle resulting from the combination of process parameters (i.e., pressure, temperature, and superficial gas velocity) to which the pipeline has been exposed over its operational history.*
- Not only is much of this information unknown for older systems, but is the highest critical inclination angle the best one to dig, considering all of the varying flow variables?
- More reliable for transmission systems than distribution.



Internal Corrosion Direct Assessment

- Some models are unable to account for all of the intricacies in regions.
- There are few regions that have controlled environments; based on seasonal use, on-demand customers, the addition or subtraction of laterals, etc., it is difficult to model systems based on the known parameters.
- Rules permit the use of ICDA, but by no means is it perfect!
- Prudent operators would perform additional digs where science indicates liquids may collect, even if outside of the required regions.



External Corrosion Direct Assessment

- Many operators not correctly identifying regions for ECDA.
- *NACE SP0502-2008: 3.5.1.1 The pipeline operator should define criteria for identifying ECDA regions.*
- *3.5.1.1.1 An ECDA region is a portion of a pipeline segment that has similar physical characteristics, corrosion histories, expected future corrosion conditions, and that uses the same indirect inspection tools.*
- The current language present in this standard is ambiguous and lends itself to different interpretations.



External Corrosion Direct Assessment

- What is defined as “similar physical characteristics?”
- Diameter?
- Wall Thickness?
- Grade of Steel?
- Types of Coating?
- Age of Pipe?



External Corrosion Direct Assessment

- What would be similar pipeline coatings that could be grouped together in regions?
- Can coal tar enamel and asphalt be grouped?
- What about FBE and Yellow Jacket?
- Could FBE and coal tar enamel be grouped into a region?
 - Probably be a stretch to call these similar coatings.



External Corrosion Direct Assessment

- What is defined as “similar corrosion history?”
- Many operators can not demonstrate that pipe has always been cathodically protected.
- Does 1940s coated steel pipe that has always been cathodically protected share a similar corrosion history with 2000s coated steel pipe that has always been protected?
 - How would this be proven?



External Corrosion Direct Assessment

- What is defined as “similar expected future corrosion conditions?”
- Could be defined as similar soil characteristics or areas notoriously difficult to cathodically protect.
 - But all pipelines can be protected; just depends on the level of determination!



External Corrosion Direct Assessment

- Other common errors:
 - Data gathered from direct assessments is not entered into the pre-assessment step for the next reassessment.
 - Monitored indications are not being evaluated in future assessments to determine corrosion growth.
 - Remaining strength calculations not conducted.



ILI Assessment

- By far the most prevalent means of assessing high consequence areas.
- Based on inspections, appears to be less prone to error than direct assessment methodology.
- When conducted properly, provides quantitative data on the health of the pipeline as opposed to the qualitative data from the direct assessment method.



ILI Assessment

- Common errors:
 - Exceeded pig specifications for pressure, run-speed, etc.
 - Not including the tool tolerances when sizing anomalies.
 - Not checking/verifying the data provided from the vendors.
 - Pig and dig mentality.



TIMP Findings

- 192.905(a): Miscalculating PIR / HCA boundaries.
- 192.905(b)(1): Failure to contact public officials to obtain data for identified site identification.
- 192.905(c): Failure to perform PIR / HCA periodic review for transmission pipeline within distribution systems.



TIMP Findings

- 192.907(a): Not following TIMP manual:
 - Not prioritizing assessments based on risk (ASME B31.8S, Section 5.3).
 - Not requiring more restrictive criteria for ECDA and ICDA for first assessment.
 - Not performing review of RCV study.
 - Not updating TIMP manual within required timeframe after annual review.



TIMP Findings

- 192.907(b): TIMP manual deficiencies:
 - Lacking detail for how and when to update risk analysis.
 - Does not include requirements of ASME B31.8S, A3.4.2 (c) and (d) (after SCC spike test: FI leak survey, reassessment evaluation, Engineering Critical Assessment).
 - Not requiring metal loss indications >20% in a long seam of ERW or EFW to be an immediate repair condition (ASME B.31.8S, section 7.2.1).



TIMP Findings

- 192.911(k): Not keeping baseline assessment / reassessment plan or risk analysis up to date when additional data is obtained (i.e. after assessments, incidents, operational changes, etc.).
 - Changes in assessment method
 - Revised assessment / reassessment dates
 - New data for replaced segments
 - Revised risk rank / score
 - HCA boundaries
 - Revised prioritization



TIMP Findings

- 192.915(b): Knowledge and Training;
 - Not including qualification criteria for persons reviewing and analyzing ILI data.



TIMP Findings

- 192.917(a): Threat Identification;
 - Not taking into consideration the interacting nature of applicable threats in the risk analysis.
 - Not considering the threat of SCC when the conditions are present, particularly near-neutral SCC.
 - Not considering the threat of LF-ERW/EFW seam threat.
 - Not considering the threat of internal corrosion when conditions are present.



TIMP Findings

- 192.917(b): Data Gathering and Integration;
 - Not using gas quality data for internal corrosion.
 - Not using Cathodic Protection (CP) history data.
 - Not using internal / external pipe inspection reports.
 - ...
 - Not collecting data required for each threat per ASME B31.8S, Appendix A1-9.



TIMP Findings

- 192.917(c): Risk Assessment;
 - Not conducting a risk assessment per ASME B31.8S, Section 5.
 - Not considering consequence of failure.
 - Not keeping risk assessments up to date after integrity assessments.
 - Not incorporating information obtained from prior integrity assessments.
 - Improperly calculating risk for piggable section where low and high risk segments are present.
 - Not updating risk calculations after P&M measures are implemented.



TIMP Findings

- 192.917(e): Actions to address particular threats;
 - (4) Not selecting an assessment technology with a proven application capable of assessing seam integrity and seam corrosion anomalies for covered pipeline segments containing LF-ERW if any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure
 - (5) Not evaluating and remediating all pipeline segments with similar material coating and environmental characteristics if corrosion is identified on a covered pipeline.



TIMP Findings

- 192.925(b): Requirements of ECDA;
 - Not performing a root cause analysis (RCA) when corrosion is found during ECDA.
 - Including pipe segments with varying vintages and coating types in the same ECDA regions (i.e. coal tar enamel with FBE).
 - Not creating a prioritized schedule for direct examinations.



TIMP Findings

- 192.927(c): Requirements of ICDA;
 - Not using flow model methodology defined by TIMP manual.
 - Not performing appropriate number of direct examinations
 - Not performing direct examinations in appropriate locations.
- 192.929(b)(2): Not performing FI leak survey upon returning to service after SCC spike hydrotest (ASME B31.8S, A3.4.2).



TIMP Findings

- 192.933(d)(1): Not excavating immediate repair conditions within five days following determination of the condition, or providing justification and reducing pressure per 192.933(a)(1).
- 192.935: Not performing P&M measures based on risk assessment.
 - Must be additional measures beyond those already required by Part 192
 - Must be documented to “take-credit”
 - Documentation retention is “life of facility”



TIMP Findings

- 192.947: Record deficiencies:
 - Documentation showing more restrictive criteria was used for ICDA or ECDA for first time.
 - Documentation showing that the validation process includes a check (review) that the risk results are logical and consistent with the operator's and other industry experience (ASME B31.8S 5.12).
 - Documentation for identified site identification.
 - Documentation of P&M measures.
 - Documentation of annual TIMP review.

Questions or Comments?



MPSC

Michigan Public Service Commission



Thank You!

