Reconfirming MAOP Using an ECA in Covered Segments

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Abstract

Gas transmission operators are now required by regulation to reconfirm the MAOP of pipelines lacking TVC pressure test records. TC Energy (TCE) operates a 20" natural gas transmission pipeline in the Northeast US, which has 54 individual segments that meet the requirements of a covered segment as per §192.624 (a) (1). TCE performed an Engineering Critical Assessment (ECA) of the pipeline to reconfirm the MAOP. The foundation of the ECA was a full suite of in-line inspection (ILI) technologies to detect and determine the anomalies that remain in the covered segments. This includes ILI technologies capable of detecting crack-like anomalies, selective seam weld corrosion and hard spots. Certain ILI tools were also used to measure material properties and attributes. Using the material data together with other data sets, the different populations of pipes within the covered segments were identified. TCE used this ECA as pilot project. As such, a pressure test was also performed to confirm the applicability of the ECA approach. The aim of the exercise was to compare the two methods holistically across one example line to help develop a better understanding of which method should be used and when. This paper provides a walk-through of the ECA process performed by TCE and ROSEN. It is intended to provide operators with an example of how an ECA is performed and some of the critical aspects that must be considered.

Introduction

The San Bruno incident in August 2011 proved to be a landmark moment in the industry. In response to this unprecedented event, the National Transportation Safety Board (NTSB) issued several safety recommendations to PHMSA [1]. These recommendations were incorporated into the Notice of Proposed Rule Making (NPRM), which was issued in 2016 [2]. The first parts of the recommendations were introduced into the regulation, CFR Part 192 [3], as requirements effective July 2020. One of the major changes was a requirement to reconfirm the Maximum Allowable Operating Pressure (MAOP), when there are no records to support the MAOP, or the MAOP was established using the 'grandfather' rule. This requirement only applies when a specific set of criteria is met, namely when there is no Traceable, Verifiable, and Complete (TVC) pressure test record, and the segment is in a HCA, MCA, Class 3 or Class 4 location. Areas where these criteria are met are referred to as 'covered segments'. The requirement for MAOP reconfirmation is accompanied by a time limit. 50% of the covered segments that need MAOP reconfirmation must be addressed by July 2028 and 100% addressed by July 2035.

There are six methods for MAOP reconfirmation available, which are detailed in §192.624. The two main options, outside of pressure reduction, are method 1, which is performing a new pressure test, and method 3, which is performing an Engineering Critical Assessment (ECA). When MAOP reconfirmation is required, the decision seems to be between doing a pressure test or going the ECA route. There is extensive experience performing pressure tests in line with CFR 192 Subpart J, however the ECA method is relatively new. Specific parts of the ECA approach are commonly used for integrity assessment, but the holistic ECA approach, as detailed in §192.632, is a new concept.

TCE operates a pipeline that is over 40 miles long and was first constructed in the early 1950's. There have been several replacements since construction. Following a review of the MAOP records, just under 3 miles are covered segments that were identified as having non-TVC pressure test records per the criteria in §192.624. The 2.84 miles is captured in nine distinct sections.

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Due to the relatively short segments of pipe that required MAOP reconfirmation, the pressure test and ECA approaches were both considered potential options. An Engineering Justification was established, and a decision was made to pursue MAOP reconfirmation as a pilot project first completing an ECA and then subsequently conducting a pressure test. The pressure test was intended initially as a regulatory compliance project but subsequentially has served to validate the findings of the ECA by proving fitness for service at MAOP. While the ECA served to identify anomalies that might be expected to fail during the pressure test.

Engineering Critical Assessment strategy

The direction in §192.632 can be roughly split into three parts. The first part, the introduction and part of clause (a), provides direction that the ECA must "*consider the threats, loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance*". Later there is more direction regarding the scope; "*The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments*". These directives are intended to ensure that all the available information is considered when performing the ECA, and that the analysis is complete and covers all the threats to which the pipeline is susceptible. The content in these opening statements is incorporated into subsequent tasks, specifically the threat assessment and ECA analysis.

The second part of §192.632, clauses (a), (b) and (c), describes the process of performing an ECA analysis. This includes identifying the anomalies that exist in covered segments and calculating the predicted failure pressure or otherwise confirming that the anomalies are fit for service at the MAOP. The anomalies present will almost certainly be identified using in-line inspection (ILI), which was the case in this project. Regulation provides specific guidance on what ILI is required based on the threat assessment and experience or information at hand. The analysis of remaining anomalies must be performed using TVC material properties and industry accepted models. In the case of metal loss and crack-like anomalies prescriptive guidance is given on which models to use. The MAOP is reconfirmed based on the lowest predicted failure pressure. Alternatively, the required MAOP can be reconfirmed by remediating anomalies that have a predicted failure pressure higher than the MAOP multiplied the requisite safety factor.

The final part of §192.632, clauses (d) and (e), cover activities that are required beyond reconfirming the MAOP, namely calculating the remaining life and ensuring that the ECA is supported by retention of records.

The MAOP of the segments under consideration is 500 psi. To achieve the same factor of safety resulting from a pressure test, the anomalies existing in the pipeline must be assessed against the MAOP multiplied by the relevant safety factor depending on class location and construction date. There were class 3 and class 4 locations and so the highest safety factor was 1.5, resulting in an assessment pressure was 750 psi.

Threat assessment

A complete threat assessment was performed by TCE. When threats are identified, they are addressed in accordance with the Integrity Management program (IMP). It is beyond the scope of this paper to detail the outcome of each threat, and so the most significant parts affecting the ECA are discussed below. Other threats such as equipment failure, incorrect operations, and thermal stress are all accounted for, but did not require any specific action for the ECA and MAOP reconfirmation.

The line is coated with low performance coal tar coating and was constructed in the early 50's therefore the line is considered susceptible to external corrosion. The threat of external corrosion is always considered active and is actively managed through ILI assessment with subsequent remediation and mitigating actions.

Selective Seam Weld Corrosion (SSWC) is primarily a weld-related defect and is considered more of a threat on autogenous pipe material manufactured prior to 1970. This line was originally constructed with vintage pipe manufactured by Youngstown Sheet and Tube Co., AO Smith Corporation, and National Tube Corporation. Pipe manufactured by Youngstown, between 1949 and 1970, is DC ERW and is considered susceptible to SSWC, as is low-frequency ERW pipe manufactured prior to 1970. The line is considered susceptible to SSWC, and an appropriate ILI assessment was performed as part of the ECA.

Although the pipeline is coated with a low performance coating, it operates below 60% SMYS. There have been no instances of Stress Corrosion Cracking (SCC) or Circumferential SCC (CSCC) identified through direct examination. In addition, the pipeline has not experienced any in-service ruptures or leaks due to SCC. Notwithstanding the low threat susceptibility, ILI assessment using EMAT has been performed as part of the ECA.

Knowledge of Manufacturing, Fabrication and Construction (MFC) threats and the potential for the presence of anomalies is based on failure history, understanding the types of pipe present, pipe manufacturing process, vintage, and other information such as past inspections and validation. The Line is considered susceptible to the following: seam weld anomalies, hard spots, pipe mill and construction anomalies such as gouges, scrapes etc. Pipe manufactured prior to 1960 by AO Smith and Youngstown is considered susceptible to hard spots. Based on current knowledge and experience in the industry, cracking at hard spots is considered a threat on the line. An appropriate technology to detect hard spots was included in the assessment, to complement the use of EMAT to detect any cracking present.

Girth weld flaws are considered an integrity threat if they are interacting with corrosion, stress concentrators or additional loads. There have been no failures related to girth-weld anomalies on the assessment path, and so a specific ILI was not included in the assessment, however, a review of girth weld integrity was included in the ECA using a bending strain analysis.

The threat of mechanical damage is managed through a specific threat management program (EDMS No. 006786487) and is directed at both internal and external stakeholders who plan to engage in activities in the vicinity of the right of way. A review of the failure database revealed an incident caused by external interference from a farmer striking a one-inch tap. There have been no other mechanical damage in-service leaks or ruptures on this assessment path. The instrumented aerial patrol performed in 2022 did not report any leaks. The threat of mechanical damage exists and

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detecting remnant damage is covered by the ILI assessment performed to address a range of MFC anomalies.

The threat of outside forces is managed through includes proactive geo-hazard assessment, which involves desktop studies of geology, terrain type, seismicity and regional history of ground stability, and aerial/ground reconnaissance by experienced professionals. Aerial patrol is also performed and collaborates with regional personnel or landowners to identify potential issues. This line traverses generally flat farmland, with no significant water crossings. Based on the topography of the line, the threat of weather and outside forces is considered low. Notwithstanding, a bending strain analysis was included in the ECA.

Typically, the pressure cycling in gas transmission pipelines is not severe. However, due the potential for crack-like anomalies, the threat of fatigue was covered as part of the ECA. Pressure cycling is monitored periodically at intervals and that data is used to perform a fatigue assessment.

Determining defects in the pipe

One of the significant benefits of the ECA approach is that it can be planned to align with the scheduled ILI program. As previously discussed, 50% of the MAOP reconfirmation must be completed by 2028 and 100% completed by July 2035, so there is a window to plan the ILI. In that sense, if the selected ILI program covers all the threats that are identified under the ECA the only additional costs are those associated with the ECA analysis and remediation.

To support the ECA, the following ILI was performed, in accordance with §192.493:

1. Metal loss Detection with Geometric Analysis using axial MFL[1]
2. Metal loss Detection and SSWC using high resolution[2] circumferential MFL
3. Crack Detection using EMAT[3]+CMFL
4. Hard Spot Detection using dual field MFL[4]
5. Material Properties using RoMat PGS[5]
6. IMU[6] for spatial data and bending strain

A summary of the anomalies reported across the various ILI systems is shown in Table 1.

[1] Magnetic Flux Leakage
[2] High resolution set-up for detection, identification and sizing of corrosion on the longitudinal weld seam and SSWC
[3] Electro Magnetic Acoustic Transducer
[4] High and low field Magnetic Flux Leakage
[5] Pipe Grade Sensor which is achieved using eddy current in a magnetic field
[6] Inertial Measurement Unit

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Table 1. Anomalies in the covered segment

Metal loss anomalies	Number Reported	Maximum Reported Depth (%wt.)	
Internal Corrosion	379	20	
External Corrosion	56	30	
Internal Manufacturing Anomaly	984	25	
Crack-like anomalies	Length (in.)	Depth (% wt.)	
Longitudinal weld crack-like	2.90	26.00	
Longitudinal weld crack-like	7.50	33.00	
Longitudinal weld crack-like	4.02	25.00	
Longitudinal weld crack-like	4.81	33.00	
Longitudinal weld crack-like	2.37	26.00	
Longitudinal weld crack-like	3.52	26.00	
Longitudinal weld crack-like	6.46	37.00	
Longitudinal weld crack-like	7.02	33.00	
Geometric anomalies	Number Reported	Max. ID Reduction	
Dent	1	2.1%	
Ripple	2	1.3%	
Hardness anomalies	Width (in.)	Length (in.)	HRB
CAD weld[7]	1.72	1.22	-[8]
Hardness anomaly	1.87	1.36	259
Hardness anomaly	1.59	1.09	263
Hardness anomaly	1.80	1.38	257
Hard spot[9]	1.76	1.40	-[10]
Hard spot[9]	2.79	1.74	287
Strain anomalies	Length of Strain Area (ft.)	Maximum Bending Strain (%)	Strain Direction
Bending strain	300	0.15	various
Bending strain	145	0.18	various
Bending strain	120	0.16	various

Material Properties and Attributes

As per §192.632 (a) (1), the material properties used in the ECA must be based on TVC records or conservative assumptions. TCE undertook an extensive program to verify the material properties and attributes along the line in accordance with §192.607. This program incorporated ILI to identify the individual populations within the inspected segments and measure material properties and attributes. ILI confirmed that there are 9 different populations of pipes, and 3 different populations of bends in the covered segments. The ILI was supplemented by non-destructive testing and available

[7] CAD weld
[8] Hardness not reported for CAD welds
[9] Using tool tolerances these anomalies met the criteria of a hard spot in regulation of hardness >327HB and a dimension of 2 in. in any direction
[10] Hardness not reported and conservatively assumed to be > 327 HB

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documentation. The material properties and attributes of eighteen joints were tested using NDT. The populations that are contained within covered segments, and the TVC material properties and attributes in each population are summarized in Table 2. For the variables, green shaded cells denote a property that is TVC, and red shaded cells denote a property that is not yet considered TVC. Fracture toughness data is not included, as all the crack-like anomalies in the covered segments were remediated following ILI reporting.

Table 2. Populations and Material Property inputs for the ECA

Population	No. Joints	Length (ft.)	Length (miles)	Diameter (in.)	WT (in.)	Grade	Pipe type
A1	34	1500.1	< 1	20	0.250	X42	LF-ERW
A7	29	1066.0	< 1	20	0.250	X42	HF-ERW
A8	3	67.4	< 1	20	0.250	X42	Seamless
B11	322	11789.6	2.23	20	0.281	X42	Flash Welded
D1	1	11.1	< 1	20	0.375	X60	HF-ERW
D9	10	194.0	< 1	20	0.375	X46	Flash Welded
D10	1	42.4	< 1	20	0.375	X65	HF-ERW
D11	1	3.2	< 1	20	0.375	X65	HF-ERW
D12	8	298.3	< 1	20	0.375	X42	HF-ERW
Db5[11]	1	4.1	< 1	20	0.375	X42	Joint Factor of 1[12]
Db8[11]	8	15.3	< 1	20	0.375	X42	Joint Factor of 1[12]
Db9[11]	3	1	< 1	20	0.375	A[13]	Joint Factor of 1[12]

Documentation was available for populations A7, A8, B11, D1, D10, and D11. The documentation was considered TVC for all these populations apart from population B11. When TVC material records are not available the directives in §192.607 require testing at a frequency of 1 per mile per population, or an alternative approach. In this case 11 tests were performed in population B11, which is greater than the minimum required by regulation. Non-destructive testing included Massachusetts Materials Technology (MMT) Hardness, Strength and Ductility Tester (HSD) [4] testing to measure strength. Pipes were tested from populations A1, B11, and D9. A summary of the results is presented in Table 3. The data from testing and the TVC documentation was combined with the ILI data to define the final properties for the ECA shown in Table 2.

Table 3. Summary of NDT material properties and attributes

Population	No. pipes tested	Diameter (in.)	WT (in.)	YS range (ksi)	UTS range (ksi)	Pipe type
A1	5	20	0.250	46.2 - 54.5	66.4 - 70.8	LF-ERW
B11	11	20	0.281	48.5 - 60.1	67.2 - 80.2	Flash Welded
D9	2	20	0.375	53.6 - 56.2	74.3 - 76.6	Flash Welded

[11] Populations Db5, Db8 and Db9 are bends

[12] As per Kiefner paper [5], the joint factor for wrought bends ≤ 24” manufactured post-1940 will be seamless, butt-welded, or fusion welded with a filler and have a joint factor of 1. If the bend is an induction bend manufactured from welded pipe, the pipe will be HF-ERW or SAW, both of which have a joint factor of 1.

[13] The grade has not yet been verified on this bend population. As per §192.632 (a)(2) (iv) the population can be assumed to be Grade A (30 ksi) for the purposes of an ECA until the grade is verified in accordance with §192.607.

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The grade in population Db9 has not yet been verified. There is no documentation and testing has not been performed. As per §192.632 (a)(2) (iv), for the purpose of an ECA, Grade A (30 ksi) can be assumed until the grade is verified in accordance with §192.607.

Metal loss anomalies

Of the 33 external corrosion anomalies reported, none were found to be interacting with the longitudinal weld seam in the covered segments. In the areas outside of covered segments, 14 corrosion anomalies were identified as being associated with the longitudinal weld. Through the SSWC analysis, two were identified as being 'possible" SSWC and the other 12 were identified as being 'unlikely' SSWC. Based on an internal SSWC procedure, these two anomalies were deemed too shallow in depth to be considered an SSWC anomaly, so no further investigation was required.

Metal loss (corrosion and non-corrosion) anomalies were assessed in accordance with Modified ASME B31.G, and TCE internal procedures. The assessment contains inherent conservatism. It is based on specified minimum tensile properties, nominal wall thickness, and contains a depth cut-off of 80% wt. The ILI tolerance for depth sizing beyond 10% wt. was applied to the calculations. The predicted failure pressures for the metal loss corrosion and non-corrosion metal loss anomalies are presented in Figures 2 and 3. All the metal anomalies have a predicted failure pressure well above the required value for MAOP reconfirmation of 750 psi (1.5 x MAOP). The data presented in Figures 2 and 3 also confirms that no metal loss anomalies were reported with a predicted failure pressure below 1.1 x MAOP, that would require immediate response per §192.933. None of the metal loss anomalies in the covered segment were associated with the seam and therefore the threat of SSWC was not considered as part of the ECA.

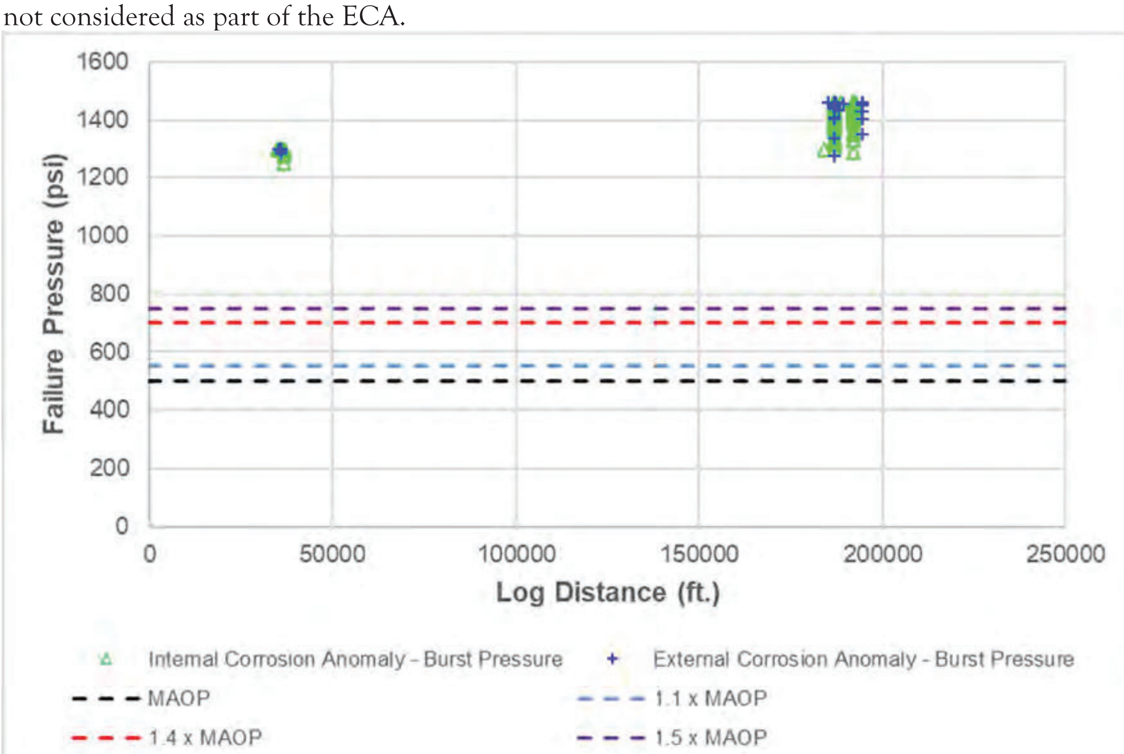

Figure 1. Predicted failure pressures for metal loss corrosion anomalies

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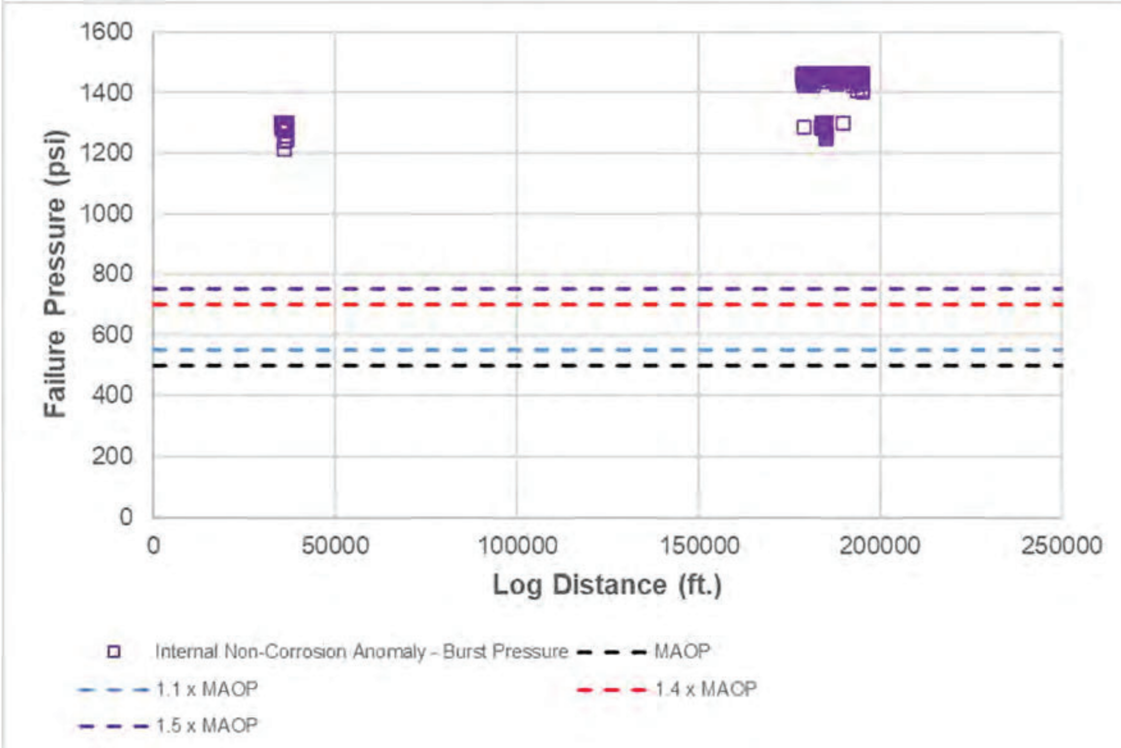

Figure 2. Predicted failure pressures for non-corrosion metal loss anomalies

Crack-like anomalies

All eight crack-like anomalies were remediated, and therefore analysis of predicted failure pressure was not required. All crack-like anomalies were reported in the longitudinal weld seam, and none were reported in the pipe body. This supports the threat assessment, which identified that the line is not susceptible to SCC, in either the axial or circumferential direction and did not need to be considered any further for ECA reconfirmation. Clause §192.632 (e) states that a remaining life must be considered if the pipeline segment is susceptible to cracking. Pressure cycling data was provided for a two-year period between August 8, 2021 and August 8, 2023.The pressure data was considered representative of the past and future operation of the pipeline and was screened through API 1176 [6]. Based on the provided data and a MAOP of 500 psi, the equivalent number of cycles per year is low and anomaly growth due to fatigue was considered negligible.

Geometric anomalies

The geometric anomalies were assessed under static conditions only. They were not associated with metal loss, cracking or stress raisers. The dents were assessed in accordance with the direction given §192.933 and ASME B31.8 [7] using dent profiles captured during the inspections. None of the geometric anomalies had strains greater than the allowable stain criteria of 6% for plain dents. The maximum strain was 3.9 %. Therefore, none of the dents analyzed in the dent strain report are susceptible to cracking because of the deformation. The strain limits used in this assessment were based on the lower bound screening limits from ASME B31.8.

Hard spots

Six hard spot anomalies were reported in the covered segments. Two of the anomalies met the definition of a hard spot in regulation, as they had a hardness > 327 HB and a length or width greater than 2 inches, considering tool tolerance. It is not possible to calculate the failure pressures of hard spots and there are no response criteria defined in regulation for either integrity assessment or MAOP reconfirmation. Based on current understanding of managing the threat of hard spots [8], it is acknowledged that hard spots alone are not likely to fail in absence of interaction with other anomalies or threats. The locations of the hard spot anomalies were cross-checked in the other ILI data to confirm that there were no interacting anomalies. The EMAT signal data has been reviewed and cross checked and no crack-like anomalies were found in the pipe body or to be interacting with hard spots anomalies. No anomalies reported from other ILI technologies were found to be interacting.

Bending strain

Three areas of bending strain were identified through a bending strain analysis using the ILI data from the IMU. The level of bending strain identified at the three locations in the covered segments were not considered significant. The bending stain locations have been recorded. Should there be a need to reconsider the threat of circumferential cracking or girth weld anomalies in the remaining life of the line, these locations may be used for validation as they are areas where additional loading may contribute to a higher susceptibility.

Other considerations for the ECA

The ECA process guidance is heavily focused on analyzing predicted failure pressures. However, this is not the only analysis required, particularly when the threats or anomalies cannot be adequately assessed using a failure pressure calculation. A good example relative to this project is hard spots. The six hard spots reported in the covered segment were deemed acceptable at the MAOP through a review of reported dimensions and potential interaction.

SSWC is particularly difficult to manage within an ECA. Fortunately, there were no corrosion anomalies associated with the longitudinal weld seam reported in the covered segments of the line. The first issue with this threat is identifying if the corrosion is SSWC or just corrosion crossing the weld seam. If correct identification has been achieved, then the confirmed SSWC must be treated as a crack. Using a safety factor of 1.5, especially with conservative toughness values and SSWC growth rates, would likely result in remediation of all SSWC.

Clause §192.632 (a) (3) states that interaction of defects must be considered to determine the most limiting failure pressure. In most cases ILI vendors and operators struggle to assess the failure pressure of interacting defects, for example cracks in corrosion. In this project there were no interacting anomalies identified in the covered segments. The easiest response to interacting defects may be remediation, notwithstanding the costs and accessibility issues. If that is not possible, an appropriate assessment method is used to perform an analysis.

The pressure test method, described in§192.624, is a one-time action and MAOP reconfirmation is achieved as soon as it is completed. Owing to the complexity of the ECA, there could well be a significant period before completing the ILI and closing the ECA. There is guidance in §192.632 (b)

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(1) related to the potential growth of anomalies between a pressure test and an assessment. Although not explicitly stated the premise also applies when using ILI. Any potential growth between the ILI and completion of the ECA must be incorporated. This means performing crack and corrosion growth assessments. Corrosion growth was considered in this project. Reliability based assessment was completed on 1,810 reported corrosion features (123 clusters, 1,687 individuals). Corrosion growth rates were calculated using signal-to-signal run comparison between the 2018 and 2021 ILI data completed by the ILI vendor. The maximum growth rate was 0.0122 inches/year. There are two (2) indications predicted to exceed reliability-based thresholds before the re-assessment ILI in 2027.

§192.632 (c) clearly states that specific ILI must be used in the ECA but does not preface that with a discussion about susceptibility. It reads that the listed ILI must be included, even if the threat assessment confirms the line is not susceptible to particular threats. The guidance only considers susceptibility related to hard spots and girth weld cracks. This may lead to ineffective use of resources and the recommendation is that threat assessment be used to drive the scope of ILI and justified within the ECA. This is important when considering that the primary alternative to an ECA is a pressure test, which will not address some of threats, specifically circumferential cracking, girth weld defects, and hard spots (without associated cracking).

Records

In the same way that records must be retained for the pressure test including the set-up, procedures and pressure wheel, Operators must also retain all the relevant records for the ECA. Considering the scope of an ECA, this is a significant task. A checklist was created for documentation including such things as analysis procedures detailing the inputs used, mechanical test records, validation reports, etc. The records must provide a historical reference that future stakeholders can depend on to manage the integrity of the assets.

Pressure test

As stated previously, the covered segments were also pressure tested. This gave TCE the ability to not only compare the costs involved in both options, but also to validate that the ECA serves its purpose. The ECA confirmed that there were no anomalies in the line that would be expected to fail the pressure test; therefore, a successful test provides validation and supports the use of ECAs moving forward.

TCE performed a Notice of Program Violation (NOPV) hydrotest project on this line following the investigation and completion of all immediate and regulatory conditions on this line. The NOPV hydrotest project consisted of 4 hydrotest segments. Segment 1 was hydrotested from Station 368+19 to 368+41, station 392+83 to 393+17, and station 408+71 to 408+99. Segment 2 was hydrotested from Station 409+48 to 409+97. Segment 3 was hydrotested from Station 432+75 to 433+01, and 482+79 to 483+18. Finally, Segment 4 was hydrotested from station 541+40 to 541+92.

Pressure test or ECA?

The ECA is very involved and includes a range of activities that would not be required for the pressure test approach. A pressure test can be executed, without the need for ILI, as it relates to MAOP reconfirmation. In most cases, if the pipeline is piggable, there will be existing knowledge of the

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defects in the line and therefore some measure of the risk of a failure in the pressure test can be defined.

One exception is that material property and attribute verification in accordance with §192.607 is required for both methods. For the pressure test method, the material verification activities remain opportunistic and have no regulatory completion date. For the ECA method, material verification must be completed before the ECA analysis can be done, unless conservative assumptions are used. In many cases using a default value of Grade A would not satisfy the required MAOP. In the case where crack-like anomalies exist, the predicted failure pressure using conservative values in §192.71 would likely result in a significant amount of remediation. Therefore, the cost of doing material verification exists for both methods, and the decision centers on when the cost is incurred.

The pressure test is a simple pass or fail test. It provides assurance that there are no defects above a critical size in the line for operation at the MAOP; however, it does not provide any detail about exactly what exists in the line. Performing an ECA, gives a full diagnosis of the line condition when ILI is implemented. In cases where ILI is already being executed, the cost of ILI is covered by existing budgets and the additional cost of an ECA comes only from the analysis and accelerated material property verification activities. Furthermore, the ECA approach allows the operator to consider 'future proofing'. The ILI data is collected along the full pipeline length, and therefore non-covered segments that could potentially become covered segments in the future can be assessed and the MAOP reconfirmed in preparation for any class location changes on the line.

To determine the financial feasibility of an ECA, there are many factors that need to be considered. To start, it is critical to identify all 192.624 applicable segments and segments operating above or equal to 30%SMYS where no TVC hydrotest record exists on the targeted assessment path. Once both these groups have been identified, an algorithm can be developed toto optimize grouping segments based on proximity to one another (for example if 2 segments are separated by less than 50 feet of pipe, these 2 segments would be grouped as 1 segment) and cost feasibility determination for performing a hydrotest or pipe replacement. The threat lead or integrity engineer is tasked with identify all threats present in the applicable segments during the feasibility study. As soon as the feasibility study is completed, the scope of assessment (ILI) required on each assessment path to address these threats is identified.

To determine the cost of pipe replacement or hydrotest, TCE built a model using outer diameter, and length of pipe as variables in determining average cost. The costs are compared to determine which on the options, pipe replacement vs hydrotest vs ILI tool is the most cost effective Above a certain length, the optimal cost solution is ILI and hence ECA. While shorter segments with isolated threats could be addressed with either a hydrotest or pipe replacement. To minimize the cost of an ECA it is ideal to execute your ECA during the time at which most of the ILI runs are scheduled or have recently been ran. Also, to note that for most operators it is ideal to run any remaining ILI tools 4 to 6 months prior to your high demand season (usually winter), to minimize commercial impact when cut out is deemed necessary, for collecting pipe attribute information.

Conclusions

Several options are available for reconfirmation of MAOP. Reducing the MAOP or pipe replacement are often not viable. TCE is currently reviewing its pipeline system to identify where MAOP reconfirmation is required, and which reconfirmation options are more cost effective. The pilot

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project discussed in this paper provided TCE with a better understanding of the critical considerations, namely the length of the covered segments when pressure testing becomes prohibitively expensive, and a comprehensive understanding of the threats existing in the covered segments (which influences the scope of ILI required for an ECA). An advantage of the ECA approach is that the integrity of the non-covered segments can be assessed at the same time. The ILI data needed for an ECA is collected along the full piggable section. This provides a basis for future proofing should more segments of the line fall under the definition of a 'covered segment' as class locations are expanded, or development occurs along the right of way. ECA is a relatively new concept, and the structured approach taken in this pilot project enabled TCE to confirm that the established procedures and processes are effective and can be rolled out across whole pipeline system. Using the experience gained to date, TCE is confident it can complete MAOP reconfirmation within the regulatory window of 50% of the system by 2028 and 100% of the system by 2035.

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