A Review, Analysis and Comments on Engineering Critical Assessments as proposed in PHMSA's Proposed Rule on Safety Of Gas Transmission and Gathering Pipelines

Prepared for the
Pipeline Safety Trust

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May 16, 2016

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Abbreviations

ANSI/ASNT – American National Standards Institute/American Society of Nondestructive Testing	API – American Petroleum Institute
ASME – American Society of Mechanical Engineers	CFR – Code of Federal Regulations
ECA – Engineering Critical Assessment	EMAT – Electromagnetic Acoustic Transducer
ERW – Electric Resistance Welding	ILI – Inline Inspection
IM – Integrity Management	MAOP – Maximum Allowable Operating Pressure
NACE – National Association of Corrosion Engineers	NPRM – Notice of Proposed Rulemaking
PFP – Predict Failure Pressure	PHMSA – Pipeline and Hazardous Materials Safety Administration
POD – Probability of Detection	POI – Probability of Identification
PQ – Personnel Qualification	PRCI – Pipeline Research Council International
SCC – Stress Corrosion Cracking	SSC – Selective Seam {Weld} Corrosion
STD - Standard	

I Introduction

This paper focuses on the important subject of Engineering Critical Assessments, or ECAs, as presented in the recent Notice of Proposed Rulemaking ("NPRM") for natural gas transmission and gathering pipelines.[1] The NPRM, proposes to allow ECA under a new regulation addition, §192.624(c)(3), as one of six methods to ascertain gas pipeline maximum allowable operating pressure, or MAOP, on certain often called "grandfathered" pipelines containing specific mentioned threat anomalies.[2, 3] In addition, the NPRM also incorporates additional detailed fracture mechanics modeling regulatory requirements to analyze pipeline that may contain specific identified anomalies that could result in pipeline rupture as a new section §192.624(d).

The September 9, 2010 San Bruno pipeline rupture and tragedy has been attributed to a crack-like "seam" anomaly that became unstable and that grew with time on a pipeline segment that had never undergone hydrotesting, under grandfathered regulations defining MAOP. PHMSA reports additionally that, between 2010 and 2014, fifteen other reportable incidents were attributed to seam failures.[4] Seam failures fall into the category of crack threats, and tend to fail as ruptures. While one intent of the integrity management ("IM") rule was to avoid such failures, these recent failures come as no surprise to this author given the number of pipeline investigations on pipelines using ECA that have rupture failed decades before ECAs predicted, and at pressures much lower than MAOP, in what I call the "negative safety factor" region of pipeline normal operating pressures. Further clarifications in high pressure pipeline integrity management regulatory approaches regarding ECA fitness for service of gas pipelines are definitely warranted, and PHMSA has expended considerable effort in identifying key parameters that influence prudent ECAs for pipelines.

A careful study of the proposed NPRM 549 page document explaining many of PHMSA's approaches will demonstrate, in my opinion, that PHMSA has done their research and homework and is taking appropriate steps to codify needed clarification actions into additional federal pipeline safety regulation utilizing ECAs as they apply to pipeline MAOP

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[1] Department of Transportation, Pipeline and Hazardous Material Safety Administration ("PHMSA"), "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 49 CFR Parts 191 and 192, Docket No. PHMSA-2011-0023," posted on March 17, 2016.

[2] The term grandfathered usually indicates the pipeline has never undergone a hydrotest, but is using previous operating pressure to establish MAOP.

[3] 49CFR§192.3 Definitions, defines the MAOP as "the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part."

[4] NPRM, p. 30.

and integrity management analysis. The effectiveness of this NPRM will depend on whether lobbying efforts undercut the clarity of the ECA regulation efforts that are currently proposed by PHMSA in this area. Such efforts can negate the safety intent of ECA applications in anomaly failure prediction, especially as they relate to crack or crack like threats on high-pressure pipelines such as transmission pipelines. In my opinion, stress corrosion cracking, or SCC, evaluation by ECA still remains an unreliable MAOP validation technique, that hopefully SCC Direct Assessment proposed by the NPRM to be incorporated by reference, may yet adequately address. To be fair, many pipelines do not contain the risks of SCC.

II Description of what an Engineering Critical Assessment is as related to this proposed rule

The term Engineering Critical Assessment and analysis (identified as "ECA") is not specifically defined in the proposed rulemaking. The rulemaking does explain in a proposed new section permitting determination of MAOP (§192.624(c)), using Method 3: Engineering Critical Assessment, that "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."[5] Industry standards further explain, though also don't define the term, as "ECA is a rigorous evaluation of the data that reassesses the criticality of the anomaly and adjusts the projected growth rates based on site-specific parameters."[6] In more layman's terms, I see ECA as an analysis process utilizing fracture mechanics principles to determine if a pipeline is structurally sound enough to meet the service requirements for which it was intended, for a specific period of time.

One perspective on the history of ECA development as it relates to pipelines might prove helpful. The science of fracture mechanics was developed and significantly advanced during World War II when steel Liberty ships started to fail catastrophically (breaking in half). For pipelines, the science of fracture mechanics applications tended to progress and follow the initial development and use of inline inspection ("ILI"), or smart pig tools in the mid to late 1980's that were first focused on pipe deformation (usually the less complicated to assess) and also on general corrosion threats for obvious reasons. As pipe location/deformation/caliper tools and general corrosion ILI tools (as well as computers) improved, the engineering approaches and fracture mechanics science advanced, subject to various limitations and/or boundary conditions. As general corrosion evaluations were more

[5] *Ibid.*, p 473.

[6] Incorporated by reference into Federal pipeline safety regulation, "ASME B31.8S – Managing System Integrity of Gas Pipelines – 2004," p. 24.

complicated to assess, failure research testing on pipe sections containing general corrosion was performed by Battelle that resulted in the development and issuance of ASME B31.G for pipe general corrosion fitness for continued service that incorporated prudent safety margins.[7] Ironically, despite these advancements, corrosion still remains one of the significant failure mechanisms for transmission pipelines. Some of the reasons for such continued corrosion failures are related to misuse of ECA approaches discussed in this report that I believe are properly addressed by PHMSA in the NPRM.

In the 1990's and 2000's, attempts were made to try and develop cracking ILI tools to address various vintage manufacturing (e.g., vintage ERW, FW) and transportation cracking threats characteristic of single crack or "crack-like" anomalies causing pipeline rupture failures. In the early 2000's ILI tool evolution attempted to detect crack colonies or "crack-field" threats that manifest neither as quite pure corrosion nor purely cracking. Crack-field colonies are associated with stress corrosion cracking (SCC) and corrosion fatigue (another form of environmentally assisted cracking) and require more complex ECAs than conventional single crack or crack-like threats, though they tend to fail more like cracks. Single crack-like anomalies utilize ECAs that estimate crack growth rates through a combination of corrosion crack and pressure cycling. Crack-field growth rates, such as what occurs in significant SCC, are more difficult to estimate/predict for ECAs as the presence of multiple cracks that can interact or link unpredictably via corrosion and/or pressure cycling may not be linear or predictable.[8] Unfortunately, despite many ILI claimed advances, ILI cracking tools today still have many limitations, though I understand and encourage continued advancement in their application. Tool tolerances must be incorporated in IM programs and their associated ECAs as clarified in the NPRM.

III Description of what an ECA should include to adequately assess the safety of a pipeline

There are three primary components in performing a proper ECA for a pipeline:

1) The threats that could cause a pipeline segment to fail by rupture need to be properly identified.
2) Assessments must accurately measure each at-risk anomaly.
3) Fracture mechanics approaches performed on the identified at-risk threat must incorporate assumptions **<u>that are truly conservative</u>**.

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[7] ASME B31G-1991, "Manual for Determining the Remaining Strength of Corroded Pipelines: a Supplement to B31, Code for Pressure Pipeline."

[8] Some forms of SCC are not significant, even not readily observable by the naked eye. These non-significant forms of SCC can usually be remediated by careful "buffing" to remove the colony, if such remediation activity doesn't overly penetrate the pipe wall.

While item 1 above should be intuitively obvious, the misuse of various assessment approaches (such as utilizing direct assessment for threats not permitted in regulation, or not incorporating ILI tool accuracy and tolerance in associated ILI ECAs) indicate that something else is driving threat identification/evaluation other than failure avoidance in too many integrity management approaches. The NPRM clarifies, via additional regulatory definitions, a series of anomalies that have proven to be problematic in pipeline ruptures.[9] The NPRM, however, leaves moot how best to identify these anomalies, but places the obligation on the pipeline operator to identify and access. Once a category of threats has been identified as a possible failure mechanism on a pipeline segment, specific assessment approaches must be used that instill a high degree of confidence that at-risk anomalies can be determined and measured to a detail that permits a prudent ECA. More severe at-risk anomalies are usually direct field measured to confirm, for example, ILI vendor claims of ILI tool tolerances, to insure reliable ECAs.

Depending on the type of threat (deformation, general corrosion, cracking), its location on the pipe (near welds, such as girth or axial seam welds), and the orientation (circumferential vs. axial), the pipe can be evaluated as to its likelihood to fail within some period of time, hopefully well past the next inspection via ECAs. I discuss the three main categories of threats in further detail in the next section. In estimating time to failure by rupture using ECA approaches, some assumptions must be made as to the rate of the threat's deterioration. This can be problematic if average industry growth rates are utilized, and if such averages are much lower than actual growth rates experienced in the field at a specific pipeline location. For interactive threats, such as SCC within general corrosion wall loss, predicted growth rates can be too low and time to failure overly optimistic if they are evaluated as separate threats. SCC also has an additional complication if significant colonies of cracks, rather than a single crack, are present, as colonies of cracks can link (either lengthen or increase depth, or both) over time making rate of growth and time to failure prediction models highly unreliable.

Recent pipeline ruptures have involved too many instances where ECA approaches were utilized and the time to failure ECA predictions were off by many decades. These failures occurred at pressures well below the Predicted Failure Pressure, or PFP, clearly demonstrating the associated ECAs were anything but conservative.[10] Major problems in these approaches involved a combination of poor engineering applications including:

[9] NPRM §192.3 Definitions, pp. 431 – 439.

[10] PFP is usually stated as a ratio of the predicted failure pressure divided by the MAOP.

1) misapplying industry guidelines and/or standards beyond their limits or boundary conditions (reducing the level of imbedded safety factor included in the standard),
2) utilizing guessed or assumed values in their calculations that were not conservative, nor appropriate for the actual pipe, and/or
3) applying too low a growth rate in time to failure predictions.

An example of the first deficiency is the use of B31G for wall losses greater than 80 percent that ignores the safety factors incorporated for this standard, developed from empirical testing. The second deficiency can be shown in crack evaluation ECAs demonstrated by assuming pipe toughness properties that don't capture the extremely low values that can accelerate growth rates and shorten time to failure associated with many vintage manufacturing cracks. Growth rates may be underestimated for significant SCC colonies where multiple cracks can quickly grow nonlinearly when multiple cracks link. This is especially difficult if SCC is located in areas of severe general corrosion wall loss, placing the total remaining wall loss not only from crack but also from general corrosion, dangerously thin. The true pipe strength must be based on the actual remaining pipe wall thickness reduced by both threats interacting.

PHMSA, in its proposed ECA NPRM approach, has clearly incorporated into regulation the obligation to utilize certain important limiting conditions and/or values that should avoid confusion when applying ECA approaches such as:

1. for general corrosion, the requirement to not use ASME B31G in wall thickness losses greater than 80 percent, and
2. for vintage manufacturing crack threats "a lower toughness threshold of 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."[11]

In addition, PHMSA is proposing to require sensitivity analysis to determine time to failure including the role of the pressure-cycling spectrum and a 50% time to failure determination.[12] These requirements and the associated need to document for the life of the pipeline such analysis, should assist in minimizing misapplication of ECAs that may be neither technically nor scientifically based, what I call "a failure to exercise sound engineering judgment."

[11] NPRM, pp. 482 – 483.

[12] *Ibid.,* p. 482.

IV Discussion of the strengths and weaknesses of ECAs for different types of pipe and failure modes

Threats to pipelines tend to fall into three major fields or categories of pipe damage that are briefly discussed below:

1) Deformation
2) Corrosion
3) Cracking

4a) Deformation

Certain activities around or on a pipeline during its various lifecycle stages can cause dents, gouges, wrinkles or a pipeline to go out of round, weakening the pipe or its welds, or introduce a combination threat, a dent with a stress concentrator, such as dents with gouges. The latter, because of its unpredictability to reliably determine time to failure, is not permitted in pipelines and require that "The operator shall {field} examine these indications within a period not to exceed 5 days following determination of the condition."[13] Federal pipeline safety regulations go one step further classifying as an immediate repair condition "A dent that has any indication of metal loss, cracking or a stress riser."[14] Wrinkles are also no longer permitted on newer pipelines, but may be present on older systems.[15]

Deformation features reduce the pipe's ability to hold certain pressures because the containment structure has been changed by physical force. The science of fracture mechanics focused on pressure vessel containment, with the exception of dents with stress concentrators or dents around certain welds where the metal may have been impacted in or near a weld such as in the heat affected zone, is well established. Reliable high-resolution deformation ILI tools have been available for many years. The advancements in ILI tools in this area and the development of fracture mechanics for this category of threats yield a high degree of confidence on deformation damage ECA assessments from either field or ILI measurement on pipelines. The exception to this statement involves ECAs attempting to predict time to failure for dents with major stress concentrators or dents near welds, as the science has yet to be proven to be reliable or conservative for these specific dent threats.

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[13] American Society of Mechanical Engineers ("ASME"), "ASME B31.8S-2004 Managing System Integrity of Gas Pipelines," p. 23.

[14] 49CFR§192.933(d)(1)(ii).

[15] 49CFR§195.212(a) **Bending of Pipe**.

4b) Corrosion

General corrosion guideline development for pipelines has been well established for decades, also driven by the advancement in ILI technology starting in the mid 1980s. In the last several decades the advancements in high-resolution ILI corrosion tools, and associated software algorithms and computer improvements, have aided in the advancement of ILI corrosion identification associated with general wall loss (internal or external). Industry standards related to general corrosion wall loss and procedures to determine actual remaining pipe strength are incorporated by reference into federal pipeline safety regulations (49CFR§192.7)[16, 17] Ironically, these specific standards make clear that they do not apply to conditions with wall losses exceeding 80 percent. For wall losses approaching 80 percent, operators do not have to be very far off on their assumed corrosion rates to make time to failure predictions highly "non-conservative." I continue to run into investigations where the ECAs tried to predict time to failure with wall losses very near or exceeding 80 percent. As mentioned earlier, PHMSA has, I believe, wisely proposed in the NPRM to clarify this 80 percent wall loss limitation in federal regulation as 192.485 Remedial measures: Transmission lines (c). It is my belief that federal pipeline safety regulations place a greater obligation on pipeline operators than industry standards, even those referenced industry standards, so I strongly support PHMSA's decision to incorporate this clear requirement into specific regulation.

Given the limitations imposed in industry standards and now clarified in the proposed pipeline safety regulations, I would also place a high degree of confidence in ECAs associated with **general corrosion** from either field direct assessment or high resolution ILI tool assessments. This confidence is reduced as wall thinning approaches 80 percent loss, so a prudent pipeline operator will take special precautions on ECAs nearing this limit.

4c) Cracking

Cracking became more of a public concern in the late 1980's as various tragic vintage pipe manufacturing crack ruptures occurred causing the public to become more aware of this rupture risk that was well known in the industry. The 1990's saw the first development and field application of transverse ILI crack tools focused on manufacturing crack detection that are axially aligned with the flow of the pipeline. In addition, failures in the 1990s and 2000s, both in gas and liquid pipelines from SCC, and transportation induced cracking of larger diameter thinner wall pipe, both very different forms of crack

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[16] ASME B31G-1991 (Reaffirmed 2004), " Manual for Determining the Remaining Strength of Corroded Pipelines: a Supplement to B31, Code for Pressure Piping."

[17] PRCI PR 3-805 (R-STRENG).

failure than manufacturing cracks, also caused pipeline ILI vendors to attempt to advance ILI tools and related fracture mechanics modeling for crack identification with mixed success, even today.

A subset of corrosion, selective corrosion such as selective seam weld corrosion, or SSC, as well as SCC, and/or corrosion fatigue, must be handled differently from general corrosion. For SSC, this difference is largely due to lower pipe toughness associated with the possible "crevice seam" along/near the seam weld that tends to follow along the axially aligned heat affected zone where corrosion may focus, generating a "crack like" interactive anomaly. I have previously discussed the difficulties in estimating conservative SCC corrosion rates in significant SCC colonies where individual SCC cracks can link, both in depth and in length, to cause pipe rupture.

There is also another form of cracking associated with poor girth welding during pipeline construction/installation that is causing pipeline rupture. In my opinion, no ILI inspection tool is currently capable of reliably ascertaining girth weld cracks despite many claims. This is one reason why some pipeline operators nondestructively inspect all girth welds during construction even though federal minimum pipeline safety regulation do not require such 100 % assessment. Because of the different hoop stresses imposed by pipeline pressure, hydrotesting of pipeline, even to 125 percent of MAOP as historically required in federal pipeline regulations, can leave very large cracks in girth welds. These cracks can survive through many years of pipeline operation only to fail when placed under different lateral stresses, such as surface loading or earth movement, or pipeline change in service such as reverse flow. There may be other technologies beyond ILI that can more reliably identify girth weld cracks, but associated ECAs not using ILI, such as direct field measurement, should be able to be reliably performed on girth weld cracks if they are recognized and accurately measured.

Given the limited developments and challenges associated with ILI cracking, either axial or circumferential (girth weld) ILI identification and characterization, I would place a low probability on ECA to reliably estimate time to failure for most cracks if girth weld crack assessment is based on ILI, or if there are severe or significant colonies of axial cracks that are often associated with SCC. Serious advancements in ILI development and associated fracture mechanics efforts and pipe properties are required in this area before ECA can be reliable for these two threat categories. Any claimed technical advances in this area should be made transparent and public.

V Discussion of possible concerns with the use of ECAs for integrity management and integrity verification

The IM regulatory process to avoid transmission pipeline rupture failure is data driven. Without reliable and accurate data, coupled with sound engineering approaches within the boundary conditions that may be included or imposed in industry standards, IM is just an illusion of safety, based on poor risk assessment or incomplete safety management applications. This author appreciates the need to advance technology and engineering fracture mechanics efforts to avoid ruptures, and some of the challenges or hurdles to assure transmission pipeline integrity utilizing ECAs. ECAs, however, must be based on sound science and engineering principles that do not involve unrealistic assumptions, oftentimes guesses, as to true pipe properties or anomaly characterizations (i.e., type, size, alignment, and location) that can quickly lead to pipeline rupture failure.

Despite continued claims of various advances in ILI crack technology, identification, and measurement, tolerances for this category of threats are highly dependent on the type of crack or cracks, the ILI technical determination approach (i.e., ultrasonic, transverse mag flux, EMAT), the crack(s) orientation/complexity, and location. ILI crack tool tolerances can cover a wide range of values, both for POD and POI. For ILI tools, POD is the probability a feature will be detected by an ILI tool, while POI is the probability of identification, the probability that the type of anomaly once detected will be correctly identified (i.e., stated usually with qualifiers and limitations). In addition to POD and POI, another important set of parameters when using ILI tools is their accuracy and precision, usually stated as a tolerance, that a pipeline operator should verify for their specific pipeline. The NPRM is requiring that such tolerances be incorporated in ECAs when used.[18]

For cracks, regarding time to failure ECA predictions, the other major variable that can confuse ECA time to failure estimates is the crack growth rate, a value that can vary considerably, well beyond a safety factor of 2, depending on the type of crack and its sensitivity to corrosion growth as well as pressure cycling growth, and other factors that can accelerate time to rupture failure (such as lateral stress on girth welds). Not all cracks are sensitive to corrosion attack, nor are all cracks sensitive to pressure cycling, so an understanding of the crack growth rate used in ECAs is critically important as even fifty percent time to failure benchmarks can be far off if too low a crack growth rate is assumed. This can be especially problematic on gas pipelines that historically have not seen aggressive pressure cycling, but by the nature of a modification or new operation, may be seeing

[18] NPRM section 192.493 requiring compliance with three specific industry standards referenced, API STD 1163-2005, NACE SP0102-2010, and ANSI/ASNT ILI-PQ-2005 when conducting in-line inspection of pipelines.

unusually high gas rates and/or highly aggressive pressure cycling, or changes in hydraulic profiles from flow reversals, a fairly new development for many pipelines.

Lastly, the NPRM mentions that some commenters have identified that ILI has severe technical limitations as to its ability to clearly identify certain cracks. My experience is that ILI is still in development concerning proper identification of cracks in girth welds, dents with stress concentrators, and significant SSC. I believe PHMSA understands the highly unreliable nature of ILI in this area and is encouraging the continued advancement in ILI, but also other technologies, as well as engineering approaches that may more reliably field determine the condition of such anomalies for continued service.

The approach in the NPRM to allow various methods to validate MAOP is most likely driven by the information that PHMSA has garnered over recent years from improved annual reporting concerning MAOP determinations. I would expect that PHMSA has discovered that there is more transmission pipeline mileage operating under the grandfathered clause of pipeline safety regulations, §192.619(c), than first expected. The various proposed methods to validate MAOP in the NPRM make sense. Permitting ECA methods where appropriate, encourage and take advantage of important technical advances concerning pipe integrity evaluation. ECA use, however, needs to incorporate important qualifiers that should be included in specific regulation to reduce possible ECA misuse via poor assumptions and unsound engineering that I have observed all too often in past IM programs, while encouraging technology improvements. I understand the need to foster such considerations especially in the further use/development of ILI applications. ILI, if properly chosen and applied, can tell operators more about the condition of a pipeline than any other assessment method, provided that the ILI tool capabilities and limitations are understood and their results prudently and timely utilized.

To keep the door open for further advancements in the NPRM MAOP determination approaches, PHMSA has wisely permitted the use of "other technologies" provided that such efforts are reviewed and approved by PHMSA before their use. PHMSA also recognizes that smaller diameter pipelines (many associated with intrastate pipelines) have significantly smaller actual rupture impact areas than larger diameter higher stress transmission pipelines. While one doesn't want rupture even on these smaller pipelines, such smaller diameter pipelines also may not be able to accommodate ILI tools. Other assessment approaches are warranted to validate a pipeline's integrity for a specific MAOP.

VI Suggested changes for the ECA proposal in this proposed rule

While strongly implying which threats need to consider ECA approaches defined in the NPRM, the proposed rule is less clear as to how certain specific threats are to be evaluated so that an ECA may be appropriate. While I believe PHMSA's intent is well meaning, this lack of clarity could leave ECAs open to less than sound engineering approaches, especially those based on assumptions that don't really apply to a specific field location. Based on many decades of observation, PHMSA may be attempting to advance new technology for certain threats (such as ILI or "other technologies"). The problem with such an effort is that the public may not be made aware of the uncertainties and risks associated with such "advances" that could result in pipeline rupture, as such engineering attempts have not been properly nor publically vetted. In many cases ILI will be the appropriate assessment method, in other cases it will not. While I understand and appreciate PHMSA's intent to foster ILI development and other technology advancements, the fact remains that certain risks that can and have resulted in pipeline rupture, have yet to be reliably determined by ILI and their associated ECA methods. The ILI has not proven reliable, or if the ILI has advanced, the associated ECA method may not be reliable or truly conservative.

Based on extensive incident investigations, I recommend that PHMSA make ECA engineering approaches associated with the following threats public upon their approval by the agency as the science and engineering are still under development for the following crack threat determinations:

1) Girth weld crack threats

Girth weld cracks are circumferential cracks at or near the construction welds joining pipe segments. Such cracks are associated with poor welding, post treatment, or inspection techniques that can leave cracks that will survive a new pipeline construction hydrotest. Such girth welds may not be radiologically inspected during construction as 100% radiological inspection is not a requirement, though some companies perform such prudent assessments as girth weld failures on gas transmission pipelines tend to fail as pipeline ruptures.[19] Girth weld cracks can survive for many decades of operation only to fail when certain new additional stresses are placed on the pipeline, such as lateral stresses and/or selective corrosion at or near the girth welds. Current ILI technology has proven to be poor or inadequate at reliably identifying girth weld cracks. PHMSA needs to identify other methods, such as certain risk factors (e.g., poor weld zone coatings) that could contribute to girth weld crack growth that have not been

[19] 49CFR§192.243 Nondestructive testing.

properly radiologically inspected. ECAs can be applied to girth welds that have been field assessed, for example.

2) **Significant SCC threats**

PHMSA is proposing to incorporate a new term "Significant SCC" via the NPRM. This approach recognizes that not all SCC will result in rupture failure if remediated before colonies can deepen or spread such that cracks link up. Because of the unpredictability of Significant SCC colonies to link via mechanisms that make growth rates highly unpredictable, ECA is not appropriate to deal with such severe threats and should not be allowed. Hydrotesting to high SMYS values may still be the only acceptable method of evaluation for pipe fitness of service for such a severe crack threat. ECAs should not be currently permitted in threats associated with Significant SCC.

3) **Dents with stress concentrator threats**

PHMSA is proposing to let stand the current regulation for "immediate remediation" once threats associated with dents with stress concentrators are discovered. While I have seen ECAs trying to predict the PFP of such dents with crack or crack like threat damage, there is no reliable evidence that failure prediction is "conservative" or based on sound engineering science. ECAs for dents with stress concentrators should not be permitted and the regulation for this threat should be left as defined in the NPRM.

In conclusion, despite my early aversion to ECA approaches based on too many pipeline rupture investigations that clearly demonstrated many flaws in various ECA approaches that claimed transmission pipeline rupture would only occur well above PFP, PHMSA's ECA approach in the NPRM is well thought out, based on sound research that has been made public, and an apparent understanding of past failures reported to the pipeline safety agency. With the exception of the three recommendations noted above, I thus support PHMSA's approach using ECA, subject to the condition that efforts do not delete the clarity submitted for MAOP methods for ECAs in the rulemaking process defined in the NPRM. Should PHMSA be placed in a situation to approve ECAs related to the three crack threats identified above, such approval should be conditioned on the requirement that the determinations and associated ECAs be made public to assure a proper and scientific vetting of the approach, and that it is indeed based on solid science and realistic engineering assumptions that are truly conservative.

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