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November 4, 2021

Pennsylvania Public Utility Commission
Attention: Secretary Rosemary Chiavetta
400 North Street
Harrisburg, PA 17120

RE: Proposed Rulemaking for Hazardous Liquid Safety Standards, Docket No. L-2019-3010267

Dear Secretary Chiavetta:

The long and difficult process of the construction of the Mariner East pipelines in our community has made all of us at West Whiteland Township much more aware of the importance of pipeline safety regulations and the need for enhanced state regulations to supplement existing federal regulations. Because the regulation of natural gas liquid transmission pipelines is far from our areas of expertise, West Whiteland hired Accufacts, Inc. to review and comment on the proposed amendments to Chapter 59 of the Pennsylvania Public Utility Code in the Notice of Proposed Rulemaking.

Comments on Notice of Proposed Rulemaking

Please accept the attached "Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations", dated October 29, 2021, in its entirety as comments submitted on behalf of West Whiteland Township.

Service Life Study Requirement

We noted the PUC's decision to close the separate rulemaking process regarding depreciation reporting and capital planning for crude oil, gasoline, or petroleum products transportation pipelines (Docket No. L-2019-3010270). While we understood the Commission's explanation about why depreciation reporting was not warranted, West Whiteland submitted comments as part of that rulemaking (noted in the order closing the rulemaking) in support of the service life study requirement born out of our experience with Mariner East. Therefore, we also noted with interest the PUC's direction to the Law Bureau to verify with PHMSA whether a service life study requirement would be compatible with PHMSA standards and therefore acceptable for incorporation into the pipeline safety rulemaking on changes to Chapter 59 which is the subject of this letter. If PHMSA does verify that the service life study requirement is compatible, West Whiteland Township urges the PUC to in fact incorporate that requirement in this rulemaking. Based on our experience with Mariner East, we also encourage you to consider making at least some portion of service life studies publicly available. As noted in 2019 comments from a prior West Whiteland Board, while concern about security risks to pipelines is understandable, the excessive secrecy that Energy Transfer has been permitted to indulge in regarding their integrity management plans has created challenges for local officials and added to public suspicion about the safety of the pipelines. The service life study requirement, and the analysis that would result from it, are an important step towards not only making liquid pipelines in Pennsylvania safer, but also in making residents feel safer, especially if they can read the studies and analysis for themselves.

PUC staffing

For years now, Township officials have seen firsthand how knowledgeable and dedicated the staff are from the PUC's Bureau of Investigation and Enforcement regarding pipeline regulations and safety. They also seem to be a relatively small group for such a large oil and gas state. And more regulations mean more work. We echo the comments made by Senator Carolyn Comitta about the need for adequate enforcement staffing, including maintaining Pipeline Safety Engineering staff levels commensurate with PHMSA's contractual commitments and ensuring that the Pipeline Safety section is staffed properly to ensure all safety inspections are performed per the PHMSA required time schedule.

Sincerely,

West Whiteland Township
Board of Supervisors

R Kumbhardare

Rajesh Kumbhardare
Chairman

Theresa Santalucia
Vice-Chairman

Joshua M. Anderson

Joshua Anderson
Supervisor

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Date: October 29, 2021

To: West Whiteland Township Board of Supervisors
West Whiteland Township
Exton, PA 19341

Re: Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations

Summary.

Accufacts Inc. ("Accufacts") was asked to review and comment on the recently posted pipeline safety rules from the Pennsylvania Public Utility Commission ("PAPUC") Notice of Proposed Rulemaking as it relates to possible intrastate liquid transmission pipeline safety.[1] The PAPUC website breaks down the liquid pipeline rules into two documents: 1) a summary discussion of comments from various parties involved in this process (the "Proposal"), much of which apparently occurred in 2019, pre-Covid, and 2) the actual offered liquid pipeline regulations ("Annex"). The original Annex posting was updated on 8/17/21 with an erratum correcting section number errors in the 7/15/2021 posting. The PAPUC is seeking additional comments on the proposed regulations provided in the Annex. These specific safety regulations apply only to pipelines determined to be intrastate liquid transmission pipelines, a determination that is not always simple or obvious, given various legal/political entanglements.

The main body of this report is subdivided into four parts:

Part 1 Commencing on page 3, discusses the importance of intrastate versus interstate pipeline designation as it pertains to pipeline safety regulation and enforcement,

Part 2 Beginning on page 4, details three serious deficiencies in the proposed Annex § 59.139 concerning hydrotesting and inline inspection ("ILI"), also known as smart pigging,

Part 3 Starting on page 8, contains Accufacts major recommendations concerning modifications to § 59.139 to addresses the technical deficiencies in the Annex's approach, and

[1] Reference website: https://www.puc.pa.gov/pipeline/pipeline-safety, safety standards §§ 59.131-59.143, published at public meeting held July 15, 2021, revised 8/17/21.

Part 4 Beginning on page 11, provides suggested additional clarifications in certain other proposed sections of the Annex.

Where I have not provided additional comment, I have found those remaining sections of the Annex to be reasonable.

From my perspective, the Pipeline and Hazardous Materials Safety Administration, or PHMSA, the office responsible for minimum transportation pipeline safety regulations at the federal level, recently made badly needed prescriptive improvements in performance-based transmission integrity management program ("TIMP") pipeline safety regulations, especially regarding the use of ILI tools.[2, 3] These recent prescriptive federal regulation changes and related evaluation protocols should improve, over time, the effectiveness of TIMP ILI assessment approaches misapplied in past performance-based regulations promulgated in the early 2000s. These early performance-based regulations resulted in many pipeline ruptures well below MOP when too many companies misapplied the intent of performance-based regulation using ILI, with all too predictable tragic consequences, resulting in pipeline ruptures, the large hole high-rate hydrocarbon releases.

I support PHMSA efforts in the important areas of hydrotesting and ILI assessment research and development, though only time will tell if further additional prescriptive safety regulations are warranted in these critical areas. As discussed in this report, advances continue to be made in hydrotesting protocol, ILI tool technology/methodology, and related pipe fracture mechanics science utilized to evaluate many pipeline threat areas identified by ILI. However, I believe we are still many years away before ILI advancements can replace the need for proper hydrotesting, especially in establishing MOP. Poor ILI tool performance or misuse by pipeline operators still leaves many ILI techniques blind to certain pipeline threats that can result in pipeline failure that a prudent hydrotest can address. This is especially true for certain at-risk pipelines containing crack risks, especially with pipe containing extremely low toughness steels, such as on some pipe, as discussed in this report. Hydrotesting assessments for such at-risk pipelines, however, should be at levels well above hydrotest pressures required in 49CFR195.304 (aka an MOP strength test) proposed in the Annex.

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[2] 49CFR§195.416 *Pipeline assessments, (c) Method*, "an operator must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or other equivalent methods for determining uncertainties) in identifying anomalies," amended Oct 1, 2019.

[3] While for gas pipelines, 49CFR§192 712 *Analysis of predicted failure pressure* I believe outlines PHMSA technical thinking for not only ILI analysis but establishes CVN trigger values and evaluation protocols for gas pipelines that may contain low toughness steel with crack threats. This science also applies to many liquid transmission pipelines.

My comments are developed on information readily in the public domain and are based on my opinions and experiences related to pipeline operation and maintenance. I have almost fifty years of experience concerning energy matters including, but not limited to many decades involving: process safety management, pipeline siting, design, operation, maintenance, integrity management, failure investigation and assessment, emergency response, and safety regulatory development, derived from numerous pipeline failure investigations.

Part 1 Why classification as an intrastate or interstate pipeline is important in transmission pipeline safety.

Intrastate pipeline safety programs can fall under a state's jurisdiction as an intrastate agent if their state legislature passes laws granting such responsibility and if the state meets annual certification requirements imposed by PHMSA. It is my understanding that the Pennsylvania Legislature, has granted the PAPUC such responsibility for intrastate liquid pipeline safety under their jurisdiction. Pennsylvania has also recently received (in years 2019 and 2021) a 60105(a) certification from PHMSA, allowing the PAPUC to act as an intrastate agent for intrastate liquid transmission pipelines, in addition to their historical intrastate agent status for intrastate gas pipelines. Such intrastate agent status permits the states to impose and enforce more stringent pipeline safety regulation on intrastate pipelines, if such additional state safety regulations are not in conflict (i.e., compatible) with minimum federal pipeline safety regulation promulgated by PHMSA.

It is important to also note that Pennsylvania has no Interstate Agent Agreement with PHMSA (based on my experience a determination/approval not lightly granted by PHMSA), as only five states currently have such Interstate Agent Agreements for liquid pipelines. An Interstate Agent Agreement permits a state pipeline safety agency to assist PHMSA in areas such as interstate pipeline inspection and oversight, but not enforcement. It is my understanding that Pennsylvania recently applied, but was not granted, Interstate Agent statis for interstate liquid pipelines. My philosophy on this matter is that there is enough pipeline work for both the state and federal pipeline safety agencies, and both parties are much improved and more effective by closer interaction on this matter via Interstate Agent Agreements. Accufacts has little patience for political turf wars that increase pipeline risks to the public. The PAPUC should further pursue the reason why Interstate Agent statis was not granted to Pennsylvania and address any possible shortcomings that might prevent approval of Interstate Agent for liquid pipelines.

Within Pennsylvania, PHMSA thus has sole pipeline safety jurisdiction, including inspection and enforcement, of interstate gas and liquid transportation pipelines. The classification as to whether a pipeline segment is an interstate or an intrastate pipeline from a pipeline safety enforcement perspective is thus very important, and such determinations can be complicated and not always obvious. It should be apparent why no pipeline segment can be both interstate and intrastate from a pipeline safety enforcement perspective. As of August 2021, PHMSA has reported that within Pennsylvania, only 126 miles of liquid pipeline were classified as intrastate while 3,341 miles were classified as interstate liquid pipelines.[4]

Part 2 Major areas of concern in Annex § 59.139 concerning hydrostatic testing and ILI reassessment.

The Annex in the above cited section states:

"§ 59.139. Pressure testing.

(a) *Scope.* This section establishes requirements for a hazardous liquid public utility conducting pressure testing.

(b) *Hydrostatic testing and reassessment generally.*

(1) Pipelines installed before 1970, must be hydrostatically tested under 49 CFR 195.304 (relating to test pressure) every 10 years and must be assessed using appropriate in-line inspection tools at least every two years. In-line inspection tools must be chosen to detect system-specific threats. A hazardous liquid public utility shall use alternating in-line inspection technologies meeting industry best practices, such as deformation, magnetic-flux leakage, ultrasonic testing and electromagnetic acoustic transducer, to monitor pipeline-specific threats.

(2) Pipelines installed after 1970, must be hydrostatically tested under 49 CFR 195.304 at least every three years.

(3) A pipeline that has been placed back in service after a leak has been repaired must be reassessed using in-line inspection at least every year until six years pass without another leak.

(c) *Hydrostatic testing in HCAs.* A new pipeline, a converted, relocated, replaced, or otherwise changed existing pipeline, or a reactivated segment of pipeline must be hydrostatically tested and reassessed using in-line inspection under subsection (b) to substantiate the current or proposed maximum operating pressure. A pipeline, or segment thereof, for which the maximum operating pressure is to be increased must be hydrostatically tested under subsection (b)."

[4] PHMSA website: https://www.npms.phmsa.dot.gov/Documents/CoopAgreementsMap.pdf, "Gas Transmission and Hazardous Liquid Pipeline Safety Programs Participating States in the Federal/State Cooperative Partnership," reported to PHMSA as of August 2021.

Hydrostatic testing, or pressure testing with water, is also called hydrotesting. Based on my many decades of pipeline assessment and failure investigation and experience, I see at least three fatal technical approaches in the above proposed section as it relates to assuring pipeline integrity:

1) **There is nothing magical about the 1970 cutoff year in pre-1970 pipe.**

While not specifically defined in federal minimum pipeline safety regulations, the term pre-1970 pipe is used throughout 49CFR§195 and is an industry generic label generally used to mean pipe with older vintage welding techniques, with associated poorer post weld heat treatment, and pipe mill hydrotesting during manufacturing, no longer utilized in modern pipe steel production. It is important to note that even more modern steel pipe should not be considered invincible or risk free from manufacturing related failure.[5] Vintage pipe and some other types of more modern pipes produced well past 1970 can be prone to longitudinal seam failure, usually rupture (the large hole, large rate releases driven by pipe fracture mechanics).[6] The term 1970 is included in the label, but there is nothing magical about this year as a cutoff year.

There is vintage pipe manufactured years earlier than 1970 where the pipe is satisfactory in the weld seam or related heat affected zone, or HAZ, integrity wise, and there is pipe manufactured some years after 1970 that is considered at-risk due to various seam weld risk threat factors introduced during manufacture that usually result in pipeline rupture. I will use the term "pre-1970" in this report to mean pipe of a vintage where its manufacturing with associated post treatment and mill testing processes, produced pipe, usually in the associated longitudinal weld's bond and/or HAZ, containing flaws or anomalies within areas of <u>exceptionally low toughness steel</u>. Such pipe can pass a 49 CFR§195.304 MOP test but later rupture (usually well below MOP), as has been readily demonstrated in many pipeline failure tragedies over the past four decades. The fracture mechanics engineers now characterize this pipe as in the lower tier, or brittle fracture zone, of a failure stress versus fracture toughness plot of a steel pipe at a specific temperature.

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[5] As demonstrated by the Advisory Bulleting (ADB-09-01, "Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe," May 21, 2009), showing that even modern manufacturing techniques need proper quality administration and quality control, or QA/QC, to assure pipe specifications are prudent and are met.

[6] 49CFR§195.303 *Risk-based alternatives to pressure testing older hazardous liquid and carbon dioxide pipelines*.

2) **49CFR§195.304 hydrotesting and ILI assessments are not appropriate for many crack risks assessments, especially in lower toughness steels.**

The Annex proposal §59.139 (b)(1), (b)(2), (b)(3), and (c) rely on a 49CFR§195.304 hydrotesting and more frequent ILI assessments to assure pipeline integrity established by a 1970 cutoff year. Based on my decades of pipeline failure investigation experience, supported by recent PHMSA research efforts discussed further below, the 49CFR§195.304 test is meant to be a new pipe test where a pipeline operator has taken prudent precautions to avoid the introduction of cracks into the pipeline.

My perspective is that these proposed assessment approaches, either hydrotest or ILI, are gravely deficient in preventing pipeline ruptures from cracks or crack like anomalies. For example, a pipeline operator under 49CFR§195.304 can lower the hydrotest pressure, and thus the MOP, to avoid a hydrotest failure. Such lowering of hydrotest pressure can leave large cracks in the pipeline that survive the lower hydrotest pressure but that can later fail well below MOP, especially if such cracks are in lower toughness steel. More frequent inappropriate 49CFR§195.304 hydrotesting is not sufficient for pipelines containing crack threats especially if the cracks are in low toughness steels.

Despite assertions from various industry representatives and ILI vendors overstating or misrepresenting ILI capabilities, there are currently no ILI smart pigging technology/tools that have the capabilities and proper tolerances to reliably determine or permit evaluation of certain pipe anomalies, such as pipe crack weld anomalies, especially those associated with vintage at-risk steel welds exhibiting extremely low toughness. Such at-risk pipe includes some low-frequency electric resistance welded ("LF ERW") and early vintage high-frequency electric resistance welded ("HF-ERW") pipe. There has also been a problem with more modern double submerged arc welded ("DSAW") pipe, where even recent ILI technology has proven ineffective in identifying crack threats that rupture failed, days after a 49CFR§195.304 MOP strength hydrotest.[7] That specific pipe eventually required the replacement of many miles of pipeline with new more modern pipe. Such anomalies, especially crack or crack like imperfections in low toughness steels, render time to failure engineering calculations/predictions, using present day ILI determinations and failure prediction modeling, unreliable. Low toughness risks also render failure prediction, such as fatigue "pressure cycling" approaches highly undependable, given the number of such pipelines that have

[7] Report produced following numerous crude oil pipeline ruptures on the California intrastate San Pablo Bay Pipeline in 2015 and 2016 after multiple ILI runs and a hydrotest, issued by the California Office of the State Fire Marshal, "Pipeline Accident Report: Failure Investigation Report – Tracy to Avon Intrastate Pipeline – Activity Report # 20160520TMW1," report date April 6, 2017.

prematurely ruptured at pressures well below MOP utilizing ILI techniques and pressure cycling approaches.

As a result of numerous pre-1970 vintage ruptures and tragedies after 49CFR§195.304 hydrotests, and more importantly, after numerous ILI assessments and associated engineering analyses, PHMSA undertook starting in the early 2010s, at the recommendation and encouragement of the NTSB following the Carmichael HVL LF-ERW pipeline rupture, an extensive multi-million dollar research effort trying to gain a better understanding of possible failure mechanisms and related more appropriate assessment approaches, including hydrotesting protocols for vintage ERW pipe.[8, 9] This PHMSA research effort made it very clear that a special high-pressure spike hydrotest (in excess of 100% specified minimum yield strength, or SMYS) should be performed in combination with the historical MOP strength test currently in federal regulation for pipe at higher risk to failure from crack threats.

3) **Doing inappropriate pipeline assessments more often is dangerous in that it creates an illusion of a safety.**

Concerning integrity management, the wording in the Annex requiring more frequent inappropriate hydrostatic and/or improper and unverified ILI assessments more often, especially if the ILI tools cannot prudently address the anomalies that caused a pipeline to fail, adds no safety benefit to a pipeline operation. In fact, a misplaced increase in assessment frequency using the wrong assessment technique creates the most dangerous of safeties, the illusion of a safety. This is especially important in the areas of ILI selection/use where there are limits to what the developing technology can identify, or where the science of failure prediction associated with such ILI determinations is still in development, a research effort not suitable for field application. Authentication of ILI vendor claims about what an ILI tool can find or miss, via important field dig verification of claimed tool indications (and even lack of indication) is a requirement that has been missing from too many ILI runs on pipelines, followed by rupture failure over the past two decades of TIMP regulation. I have often found such important field dig verifications to be unduly limited in number, or downright missing, in an ILI integrity management approach or associated ILI tool run reports.

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[8] National Transportation Safety Board ("NTSB"), "Rupture of Hazardous Liquid Pipeline with Release and Ignition of Propane Carmichael, Mississippi November 1, 2007, Accident Report NTSB/PAR-09/01," Adopted October 15, 2009.

[9] PHMSA, "Comprehensive Study to Understand Longitudinal ERW Seam Failures Phase II Final Report," August 2017, at https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.

I also take serious exception to the use of the term "meeting industry best practices" cited in the Annex. Such a term is not defined in pipeline safety regulation, and I have found that trying to foist such wording into pipeline safety regulation is one method to attempt to rewrite pipeline safety regulation while preventing public input from important pipeline safety regulation promulgation. The phrase "meeting industry best practices" should be removed from the proposed pipeline safety regulation and replaced with more specific prescriptive safety requirements where needed.

While recent advances in pipeline fracture mechanics science have been moving in the right direction to support developing ILI analysis in the application of crack evaluation, I believe we are years away before such science utilizing ILI assessment can reliably replace proper MOP verification of pipeline integrity hydrotesting for at-risk pipeline containing cracks, especially crack threats in vintage pipelines. Hydrotesting is a proof test for service with a pressure safety margin relevant at the time of the test. I favor the continued development and advancement of hydrotesting protocols and ILI technology, and associated fracture mechanics science to evaluate pipeline failure threats, but this development must be publicly demonstrated to be valid before such a leap of faith puts the public at great risks.

The PAPUC proposed regulations regarding § 59.139 (b)(1), (b)(2), (b)(3), and (c) as proposed, are technically incomplete, misleading, and unwarranted, creating a dangerous illusion of a safety. Such an illusion can create an atmosphere of unwarranted risk taking within a pipeline management team. These proposed sections need serious modification and I suggest the following guidance:

Part 3 Accufacts major recommendations concerning modifications to § 59.139 - Pressure testing section:

1) <u>On the Hydrotesting requirement proposed in (b)(1):</u>

For <u>pipelines of any vintage possibly containing crack risk threats</u>, especially such threats in low toughness steel, require that a spike hydrotest in combination with a MOP strength hydrotest be performed. The spike hydrotest shall include:

1. A minimum spike hydrotest pressure of: a) 100 % SMYS, or b) 1.5 times MOP if traceable, verifiable, and complete ("TVC") records <u>are not</u> producible for the pipeline. The spike test is to be followed with a 49CFR§195.304 strength hydrotest.
2. Require hydrotest(s) protocol to include a pressure-volume plot as part of the hydrotest procedures/record, as this important hydrotest parameter, ironically, is not specifically required in current federal pipeline safety regulations.

3. Mandate forensic analysis of any pipeline segment that fails during a hydrotest and require an associated hydrotest failure forensic report be made public on all such hydrotest failures.
4. It should be noted that if the pipe experiences numerous hydrotest failures that pipe should be considered unfit for service.

If the pipeline operator cannot demonstrate with records that are TVC that a pipeline does not contain pipe with possible crack threats, it must be presumed the pipeline is at risk to cracking and must be subject to a spike hydrotest in combination with a MOP strength hydrotest.

2) On the ILI requirement proposed in (b)(1):

ILI runs on any vintage pipe, including ILI runs claiming to be able to evaluate cracks shall:

1. Identify the threat(s) the pipeline operator has determined to be on a pipeline segment and specifically name the ILI tool or tools selected to address the identified threat(s). For the ILI tool(s) selected, list the ILI tool type (e.g., low-res mag flux, high-res mag flux, traditional ultrasonic, ultrasonic shearwave, transverse flux, electromagnetic acoustic transducer, caliper, mapping, etc.), and the specific ILI vendor(s) (most pipelines will require multiple different ILI tools as pipelines usually have multiple pipeline threats). Remove the phrase "meeting industry best practices" as it is the operator's responsibility to identify the threat(s) the ILI is meant to identify, and to provide sufficient field verification digs to support the ILI vendor's claim on the specific pipeline upon which it is being run.
2. Given the unique challenges associated with crack or crack like threats assessment in pipelines, such as at-risk vintage ERW pipe containing possible low toughness steel, a special type of ILI tool (Phased array ultrasonic, or PAUT), is becoming more pragmatic. For cracking threats on pipelines, PAUT ILI may prove capable of dealing with such crack threats. The PAUT ILI tool's tolerances to identify such cracks, however, **must** be coupled with proper field dig methods focused on crack evaluation to assure ILI tool effectiveness in this still developing, though promising use of technology.
3. ILI tool runs should be at least every 5 years if a pipeline operator can demonstrate the ILI tools claimed capabilities via field verification digs with compatible fracture mechanics science/analysis that should be made public.

My proposed 5-year timing **is predicated** on the pipeline operator performing sufficient competent field verification digs allowing the development of unity plots demonstrating an ILI tool's technical approach and tolerances are relevant for the identified threat.

Pipelines that contain crack threats can still try to advance crack ILI tool technology by running ILI tools claiming to allow prediction of crack failures, but the crack threat ILI tool run and related fracture mechanics evaluations **shall** be complemented with a hydrotest pressure spike test in combination with a MOP strength hydrotest outlined above to proof pipeline integrity utilizing such claimed crack identification tool run(s) and associated engineering evaluations.

3) **Pressure testing outlined in (b)(2) and ILI testing after "leak" failure outlined in (b)(3) proposal:**

a) On (b)(2) requiring MOP strength test every 3 years:

I believe there is no technical justification to require a reassessment to rehydrotest modern higher toughness steel pipe that doesn't exhibit crack threats and that has undergone a previous hydrotest, without a justifiable reason, such as a pipeline release, unless that pipe has never undergone a hydrotest without failure. I recommend that (b)(2) be rewritten to:

1) Capture those pipelines, if any, that have not been hydrotested previously to a strength test limit and do not have potential crack or crack like threats, and
2) if a pipeline exhibits a release even during a hydrotest, the cause of failure must be identified by a prudent forensic analysis that is made public.

Some causes of pipeline failure still cannot be properly identified or evaluated by ILI assessment. Such a forensic report of a failed pipe segment, whether in service or during hydrotesting, may indicate that a spike hydrotest is warranted by uncovering poor manufacturing processes resulting in lower toughness steel or deficient welds, or other threats that ILI cannot presently prudently assess, such as dents with stress concentrators, crack colonies, or pin hole leaks in certain locations, such as at girth welds.

b) On (b)(3) – Assessment following a pipeline leak:

In pipeline fracture mechanics, leak has a specific definition and does not include pipeline ruptures. **The term "leak" should be defined in state regulation to clearly mean any release from a pipeline**. As indicated earlier, ILI technology has not sufficiently advanced to reliably identify certain anomalies that can result in either a pipeline leak or the more dangerous pipeline rupture (e.g., dents with stress concentrators, stress corrosion cracking, cracks (especially in lower toughness steels), or crack-like colonies, pin hole leaks). An appropriate forensic analysis of the failed pipe after a release will assist in determining a proper assessment method, whether a prudent hydrotest with a spike hydrotest, or a specific type of ILI assessment, if any. There are some ILI tools that even today are well known to not be reliable at identifying certain pipeline threats, and such tools should not be relied upon, despite some industry public relations misinformation spin overstating ILI capabilities.

The above being said, running ILI tools that are able to identify other bona fide pipeline threats (e.g., general corrosion, deformation, and mapping tools) on a particular pipeline would be appropriate if these threats are present on certain pipelines. Such ILI runs still need to be supported by proper management approaches of the ILI tool's use and its findings, incorporating the limitations/appropriate tolerances of each ILI tool, supported by field verification digs that I believe are now prescribed in federal pipeline safety regulations for ILI runs.

As it relates to the important need for ILI field dig assessment/verification in the Annex §§ 59.135 (b)(2) & (e):

The Annex proposes in §§ 59.135 (b)(2) *Timeframe for notice* and (e) *Information to be provided upon request for assessments and verification digs involving an expenditure in excess of $50,0000 and the unearthing of suspected anomalies*. **I advise removing the $50,000 dollar reporting threshold limit as this arbitrary dollar value can be misused to defeat an important purpose of field verification digs, to validate ILI integrity assessment capabilities on a specific pipeline.** In today's environment of advanced spreadsheet and internet connections, it should be easy to communicate and review/monitor all field verification digs associated with ILI runs. No arbitrary dollar threshold should be imposed in regulation concerning the utilization and reporting of field verification digs. Such an arbitrary dollar threshold hurdle can be used to cherry pick or taint field verification digs, hindering neutral objective determinations of an ILI tool's capabilities and tolerances, a critical step where ILI capabilities are often misrepresented and overstated. No dollar threshold should be imposed to exclude field verification digs for ILI runs.

Part 4 Suggested additional clarifications on remaining Annex proposals that I believe are helpful.

My following observations are in the order of their presentation within the posted Annex document with my supporting comments following each identified specific section that I believe justifies further clarification beyond that which I have previous discussed:

§§ 59.135. Construction, operation and maintenance, and other reports.

§§ 59.135 (d) (2)(viii) – While historically Charpy V-Notch ("CVN") toughness has been used in pipeline failure potential evaluations, and this parameter must continue to be utilized given its past historical use, advances in fracture mechanics science are starting to shift to other toughness parameters more appropriate to recent advances in fracture mechanics science and failure prediction. However, it is still too early to affirm possible technically measurable methods that may serve as an alternative to CVN for pipelines that might be incorporated into pipeline safety regulations.[10] Such alternatives I believe are several years away if not longer, depending on the scientific soundness and

[10] For example, see PHMSA 49CFR§192.712 Analysis of predicted failure pressure, amended Oct 1, 2019.

transparency of such efforts. I suggest wording changes to permit other toughness values other than CVN, when scientifically warranted and demonstrated to support advances in this area. Such changes if they occur should be made public well before becoming regulation.

§§ §§ 59.135 (d) (3) *Information to be provided upon request generally. Operating Pressure and Stress.*
Add clarification as follows to ensure values are at MOP, a defined term in federal pipeline safety regulation:

(i) Add at MOP after pressure
(ii) Add at MOP after stress
(iii) Add clarification at MOP after (percent).

§§ 59.135 (d) (6)(ii) *valves*. Add whether valve has an actuator, specify the power source for the actuator if present (i.e., gas, hydraulic, electric), and identify if valve is SCADA (i.e., control room) monitored/controlled if remotely monitored.

§§ 59.135 (d) (9) *Pressure and leakage tests*. Add (v) indicating minimum segment test pressure as a percent of specific minimum yield strength, or SMYS, as defined in federal regulation. SMYS is an important parameter utilized in evaluating hydrotest assessment/appropriateness, ironically not required to be reported in federal regulations.

§§ 59.136 (g)(1) *Valves for transporting HVLs*. Given the uniqueness of HVL to flow out of a pipeline rupture, a not to exceed <u>minimum</u> mainline valve spacing of five miles is reasonable. The additional requirements of §§ 59.134 (g)(2) will in all probability require closer valve spacing than 5 miles for the sensitive gathering areas identified in that section, especially for larger diameter HVL pipelines.

§§ 59.138 Horizontal directional drilling and trenchless technology, or direct buried methodologies

§§ 59.138(c)(5)(i)(A). Remove "exact" location wording as such specificity can create a dangerous misimpression about the location of the pipeline, especially if the exact location can and often does change for various reasons. Such misimpressions can also undermine important pipeline safeguards intended in prudent "one call" call before you dig "811" programs.

<u>§ 59.140 Operation and maintenance.</u>

(b) *Emergency procedures manual and activities*

Under (b)(1) suggest wording to include: initiate and maintain early contact between emergency response personnel and pipeline control room personnel if pipeline is operated via a control room. Control room personnel usually have the authority to quickly shut down and isolate segments of a pipeline.

(g) *Inspection of pipeline rights-of-way.*
Add wording to emphasize looking for activities off the ROW that could also possibly endanger the pipeline. Ironically, one does not have to hit a pipeline to cause its failure at a later time.

(h) *Leak detection and odorization*
This section's proposal, though apparently well meaning, does not appear to be technically achievable on leak detection, nor does the alternate to require odorant appear viable, given my experiences with the dynamics of pipeline HVL releases. Further evaluation is warranted to see if odorization is capable of warning of a HVL release before such a requirement becomes codified into regulation.

§ 59.143. Corrosion control

(f) *Interference currents.*
Remove "direct" so that the line reads: or other current sources such as stray current.

Conclusions

The determination as to whether a transmission pipeline is either interstate or intrastate is critical as to the party that is responsible for enforcement of specific pipeline safety regulations. Such a determination is neither clear nor obvious given the many nuances or lack of clarity in law. It is important that the public be provided maps within a state indicating the approximate pipeline location and whether the pipeline segments are interstate or intrastate, as no pipeline segment can be both from a pipeline safety regulator enforcement perspective.

When it comes to pipeline integrity management, hydrotesting and ILI inspection have different strengths and weaknesses that play important roles in safe pipeline operation. These various assessment strengths and weakness are not codified in pipeline safety regulation, leading to much misapplication and numerous pipeline failures in the past two decades from misuse. I believe we are still a long way from ILI assessment replacing a new pipe hydrotest to proof pipeline integrity and fitness for service at a stated MOP. This is especially true given the lack of past transparency related to confirming ILI vendor claims on smart pig capabilities and lack of prudent field dig verifications to substantiate ILI vendor claims which are a pipeline operator's responsibility.

As discussed in this report, hydrotesting protocols for pipelines containing crack or crack like risks pipe should exceed that of an MOP strength test currently defined in minimum federal pipeline safety regulation. Likewise, while ILI has superior strengths over hydrotesting **in certain pipeline threat areas such as general corrosion**, no current ILI approach is capable, even today, of addressing pipeline threats that prudent hydrotesting can proof at the time of the test. It is important not to misrepresent the capabilities of either assessment method in verifying pipeline integrity. The PAPUC proposed regulations regarding § 59.139 (b)(1), (b)(2), (b)(3), and (c) as proposed, are technically incomplete, lack specificity, and create a dangerous illusion of a safety. These sections need to be rewritten to capture the technical limitations and processes I have discussed previously.

I believe PHMSA understands the technical limitations and different strengths and weaknesses of either assessment approach but is hindered by additional regulatory hurdles specifically imposed on PHMSA that are not required of many other agencies. It can take many years to develop or even advance prudent PHMSA safety regulations for field applications. Some state pipeline safety agencies, however, have the ability to quickly enact clearer more advanced safety standards, not in conflict with PHMSA, without such obstacles. It is thus important that such state agencies make clear and technically defendable pipeline safety regulations. It is worth mentioning again, such additional regulations proposed by the PAPUC only apply to the limited miles of intrastate pipelines under their jurisdiction.

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