NO. 16-60448

In the United States Court of Appeals for the Fifth Circuit

EXXONMOBIL PIPELINE COMPANY,

Petitioner,

v.

UNITED STATES DEPARTMENT OF TRANSPORTATION, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, OFFICE OF PIPELINE SAFETY,

Respondents.

RECORD EXCERPTS OF PETITIONER,
EXXONMOBIL PIPELINE COMPANY

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CERTIFICATE OF SERVICE

I certify that the Record Excerpts were filed with the Court via the court's electronic filing system, on the 1st day of September, 2016, and an electronic copy of the record excerpts were served on all counsel of record, as listed below, via the court's electronic filing system on the same date:

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Tab 1

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Ave, S.E.
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OCT 0 1 2015

Mr. Gerald S. Frey
Global Pipeline Manager & President
ExxonMobil Pipeline Company
22777 Springwoods Village Pkwy
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Spring, TX 77389-1425

Re: CPF No. 4-2013-5027

Dear Mr. Frey:

Enclosed please find the Final Order issued in the above-referenced case. It makes findings of violation, assesses a modified civil penalty of $2,630,400, and specifies actions that need to be taken by ExxonMobil Pipeline Company to comply with the pipeline safety regulations. The penalty payment terms are set forth in the Final Order. When the civil penalty has been paid and the terms of the compliance order completed, as determined by the Director, Southwest Region, this enforcement action will be closed. Service of this Final Order is made pursuant to 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Linda Daugherty
for
Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Rod Seeley, Director, Southwest Region, PHMSA
Mr. Bob Hogfoss and Ms. Catherine Little, Hunton & Williams LLP,
Bank of America Plaza, Suite 4100, 600 Peachtree Street, N.E., Atlanta, GA 30308

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
ExxonMobil Pipeline Company,	)	**CPF No. 4-2013-5027**
Respondent.	)	

FINAL ORDER

Pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), conducted an investigation of a pipeline accident that occurred on March 29, 2013, near the town of Mayflower, Arkansas. The accident occurred on the Pegasus Pipeline operated by ExxonMobil Pipeline Company (EMPCo or Respondent) and resulted in the release of approximately 5,000 barrels of crude oil in a residential area.[1]

As a result of the investigation, the Director, Southwest Region, OPS (Director) issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) on November 6, 2013. In accordance with 49 C.F.R. § 190.207, the Notice alleged nine violations of the pipeline safety regulations, proposed a civil penalty of $2,659,200, and proposed certain corrective action.

EMPCo responded to the Notice and requested a hearing by letter dated December 5, 2013 (Response). EMPCo submitted prehearing materials on June 2, 2014 (Prehearing Submission). In accordance with § 190.211, a hearing was held on June 11, 2014, in Houston, Texas, before a Presiding Official from the Office of Chief Counsel, PHMSA. After the hearing, Respondent submitted a post-hearing brief on July 25, 2014 (Post-hearing Brief). In accordance with § 190.209(b)(7), the Director submitted a post-hearing statement and recommendation on September 22, 2014.

[1] EMPCo is a subsidiary of Exxon Mobil Corporation and operates approximately 3,800 miles of pipeline transporting crude oil, refined petroleum products, and highly volatile liquids in Texas, Louisiana, and other states as reported by EMPCo for calendar year 2014 pursuant to § 195.49.

BACKGROUND

The Pegasus Pipeline is approximately 859 miles in length and transports crude oil south from Patoka, Illinois, to Nederland, Texas.[2] The pipeline was originally constructed and operated as three separate pipeline systems with different flow configurations. Over time the three systems were joined together and eventually became operated as a single pipeline.

The first system, which is now the Northern Section of the Pegasus Pipeline, was constructed between 1947 and 1948. The system originally transported crude oil north from Corsicana, Texas, to Patoka, Illinois. The system is 648 miles of 20-inch diameter pipe comprised of low-frequency electric-resistance welded (ERW) pipe manufactured by Youngstown Sheet and Tube Company (Youngstown) and seamless pipe manufactured by National Tube Company.

The second system was built in 1954, and transported crude oil south from Corsicana, Texas, to Beaumont, Texas. The system is 205 miles of 20-inch diameter electric-flash welded pipe manufactured by A.O. Smith Company and seamless pipe manufactured by National Tube Company.

The third system was built in 1973, and transported crude oil north from Nederland, Texas, to Beaumont, Texas. The system is 6 miles of 16-inch diameter ERW pipe. The manufacturer is not known.

In 1995, flow was reversed on the second system, and it was "tight-lined" with the third system, creating a single 211-mile system that transported crude oil north from Nederland, Texas, to Corsicana, Texas. This system eventually became the Southern Section of the Pegasus Pipeline.

In 2002 the Northern Section was idled and purged with nitrogen. In 2005 and 2006, the Northern Section was returned to service with a reversed flow to the south. The Southern Section also reversed flow to the south. The Northern and Southern Sections were "tight-lined," creating a single 859-mile pipeline system called the Pegasus Pipeline that transported crude oil south from Patoka, Illinois, to Nederland, Texas.

Mayflower Accident

On March 29, 2013, the Pegasus Pipeline suffered a failure in the Conway to Corsicana segment of the Northern Section. At approximately 2:37 p.m. CST, alarms were detected by EMPCo's Operations Control Center in Houston, Texas.[3] The first alarm was a low pressure alarm, followed by a pressure rate of change alarm. The alarms came from a surveillance site three miles from site of the rupture. The controller initiated a shutdown of the entire pipeline, including a staged shutdown of all pumps. Isolation of the failed section was achieved by closing mainline valves upstream and downstream of the rupture site. The period of time between detection of the failure and isolation of the pipeline was approximately 16 minutes.

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[2] OPS Pipeline Safety Violation Report, Exhibit B – Failure Investigation Report (Accident Report) at 1–7 (Oct. 23, 2013).

[3] Prehearing Submission at 3–4.

The maximum operating pressure (MOP) of the pipeline was 865 psig, established by a hydrostatic test pressure of 1091 psig on January 24, 2006.[4] At the time of the failure, the discharge pressure at the Conway Pump Station, approximately 15.5 miles north of the accident site, was 768 psig. Pressure at the failure site was estimated between 702–708 psig. The pipe that failed was low-frequency ERW pipe manufactured in 1947 by Youngstown.

The rupture occurred in the Northwoods Subdivision, a residential neighborhood in Mayflower, Arkansas.[5] The leak was on the right-of-way between two single family dwellings. Local emergency responders and public officials responded within 30 minutes of the release. City and county emergency responders deployed booms and built earthen dams to slow the flow of crude oil released from the pipeline.

The subdivision and site terrain have drainage paths that lead to Lake Conway, including storm drains that lead to a cove south of the main body of the lake. Crude oil flowed into these storm drains, but did not reach Lake Conway or impact drinking water supplies. Twenty-two households were evacuated, and there were minor impacts to flora and fauna in the immediate area. There were no reported injuries or fatalities related to the release. The accident caused property damage estimated by EMPCo of approximately $57,500,000.[6]

Accident Investigation and Corrective Action Order

On April 2, 2013, PHMSA issued a Corrective Action Order (CAO) to EMPCo, which required suspended operation of the pipeline, metallurgical testing of the failed pipe, and development of a remedial work plan, among other requirements.[7] After a hearing, the CAO was upheld in a decision issued by PHMSA on May 10, 2013, with modification to the pressure restriction requirements.[8]

Hurst Metallurgical Research Laboratory, Inc. (Hurst) was retained by EMPCo with the approval of the Director to conduct a metallurgical evaluation of the failed pipe and to determine the root cause of the failure. In July 2013, Hurst issued a report on the cause of the failure that stated "failure of the pipeline . . . resulted because of the reduction of the wall thickness in the upset zone of the Electric Resistance Weld (ERW) seam caused by the presence of manufacturing defects."[9] The manufacturing defects were described as "upturned bands of brittle martensite,

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[4] Accident Report at 4-5. Pressures are adjusted for elevation difference at the failure location.

[5] Accident Report at 7-9.

[6] Accident Report at 1.

[7] ExxonMobil Pipeline Co., CPF No. 4-2013-5006H, 2013 WL 2357814 (Apr. 2, 2013). Orders can also be viewed on PHMSA's website at http://www.phmsa.dot.gov/pipeline/enforcement (follow links for enforcement since 2002 and then enforcement actions/orders issued by year).

[8] ExxonMobil Pipeline Co., CPF No. 4-2013-5006H, Decision Confirming CAO, 2013 WL 3788036 (May 10, 2013).

[9] Accident Report, Appendix D (Hurst Report) at 31.

combined with localized stress concentrations at the tips of the hook cracks, low fracture toughness of the material in the upset/HAZ [heat-affected zone], excessive residual stresses in the pipe from the initial forming and seam and girth welding processes, and the internal pressure creating hoop stresses."[10]

Hurst found evidence of "hook cracks through multiple ductile and brittle zones, significant variance in hardness between the various zones of the ERW seam," "hook cracks along multiple planes through the upset heat-affected zones," and "extremely low impact toughness and elongation properties across the ERW seam."[11] In conclusion, Hurst opined that it was likely micro-cracking in the seam had occurred immediately following pipe manufacturing, and that the cracks merged by further cracking in the seam during service "forming a continuous hook crack in each of the localized areas to the critical depths, at which point the remaining wall thickness, combined with the localized stress concentration and the residual stresses, could no longer support the internal hoop stresses and resulted in the final failure."[12]

OPS issued a Failure Investigation Report (Accident Report) on October 23, 2013, after completing an investigation of the accident. OPS concluded, based on the Hurst analysis, that the pipe failed as a result of defects that were present from the time of pipe manufacture, which grew over time and ultimately failed.[13] OPS also found that EMPCo had performed hydrostatic testing assessments in 1991 and 2005–2006, which were effective in detecting similar manufacturing defects, but when conducting a subsequent integrity assessment five years later, the Company did not select a method appropriate for detecting such defects. OPS found that EMPCo had not considered the pipeline to be susceptible to seam failure.

OPS concluded that contributing factors in the failure "were the operator's actions under its integrity management program where the operator determined, incorrectly, that the pipeline was not susceptible to seam failures, and as a result, failed to assess the pipeline with a method capable of addressing that specific threat within the prescribed regulatory timeframes."[14]

Integrity Management Regulations, 49 C.F.R. § 195.452

Each hazardous liquid pipeline that, in the event of a leak or failure, could affect a high consequence area (HCA) is covered by the integrity management regulations. HCAs include populated area, an area that is unusually sensitive to environmental damage, or a commercially

[10] Hurst Report at 31.

[11] Hurst Report at 31-32.

[12] Hurst Report at 32.

[13] Accident Report at 14.

[14] Accident Report at 14.

navigable waterway.[15] Under these rules, operators must develop and follow a written integrity management program (IMP) that addresses the risks of its pipelines that could affect an HCA.[16]

The IMP must include a plan to carry out an integrity assessment of each pipeline and to address conditions discovered as a result of the assessment.[17] The schedule for integrity assessments must prioritize pipeline segments for assessment based on all risk factors that reflect the risk conditions on the pipeline.[18] Factors that must be considered in the scheduling of assessments include, but are not limited to: results of previous integrity assessments, pipe material, manufacturing, seam type, and leak history.[19]

Available methods of integrity assessment include hydrostatic testing and inline inspection (ILI). When assessing low frequency ERW pipe susceptible to longitudinal seam failure, the method selected must be capable of assessing the integrity of the longitudinal seam.[20]

After completing an integrity assessment, an operator must promptly obtain adequate information about conditions on the pipeline. The information must be obtained no later than 180 days after an integrity assessment, unless the operator can demonstrate the 180-day period is impracticable.[21] Upon discovery of any anomalous conditions, the operator must take prompt action to address the condition.[22] Discovered conditions must be addressed according to a schedule that prioritizes the conditions for remediation.[23] Certain conditions must be treated as immediate repair conditions, while others must be remediated within 60 or 180 days.[24] When an immediate repair condition is discovered, operating pressure must be temporarily reduced, or the pipeline shut down, until the condition is remediated.[25]

Operators must continue to assess and evaluate the integrity of each pipeline at periodic intervals.[26] The intervals for reassessment must be based on all applicable risk factors, but may

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[15] Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles), 65 Fed. Reg. 75,378 (Dec. 1, 2000); Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles), 67 Fed. Reg. 2,136 (Jan. 16, 2002).

[16] § 195.452(a), (b)(1), (b)(5).

[17] § 195.452(b)(3), (f)(2)–(5).

[18] § 195.452(e)(1).

[19] § 195.452(e)(1)(i)–(iii).

[20] § 195.452(j)(5).

[21] § 195.452(h)(2).

[22] § 195.452(h)(1).

[23] § 195.452(h)(3).

[24] § 195.452(h)(4).

[25] § 195.452(h)(4)(i).

[26] § 195.452(j)(1)–(3).

not be longer than five-years or 68 months.[27] In limited situations, if an operator can justify a longer assessment interval, the operator must notify OPS of the justification for a variance no later than 270 days prior to the end of the five-year (or less) interval.[28]

FINDINGS OF VIOLATION

The Notice alleged that EMPCo committed nine violations of the pipeline safety regulations in connection with the Mayflower Accident:

Item 1: The Notice alleged Respondent violated 49 C.F.R. § 195.452(e)(1), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (*see* paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:
> (i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
> (ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;
> (iii) Leak history, repair history and cathodic protection history . . . .

The Notice alleged that Respondent violated § 195.452(e)(1) by failing to establish a continual integrity assessment schedule for the Pegasus Pipeline based on all of the risk factors that reflect risk conditions on the pipeline. Specifically, the Notice alleged Respondent did not properly consider the risk that the ERW pipe on the Pegasus Pipeline was susceptible to seam failure. The Notice alleged Respondent had adequate information about the pipe's seam failure susceptibility, including manufacturing information, previous seam failures, and fracture toughness information.

In its written submissions and at the hearing, Respondent argued that it had properly considered the susceptibility of the pipe to seam failure. Respondent noted that it used hydrostatic tests, analyses using software programs, and inline inspections (ILI) in to consider seam failure susceptibility. Respondent concluded based on each analysis that the pipeline was not susceptible to seam failure.

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[27] § 195.452(j)(3).

[28] § 195.452(j)(4).

At the hearing, OPS argued the methods Respondent used to analyze seam failure susceptibility did not justify a conclusion that the pipe was not susceptible to seam failure. First, OPS stated the hydrostatic tests were not performed at a high enough test pressure and did not include a spike test that OPS contended would normally be associated with testing ERW seam integrity. OPS also noted that during the tests, seam failures had occurred, which demonstrating the pipe is susceptible to seam failure.

Respondent countered that the regulations do not dictate a minimum hydrostatic test pressure to evaluate seam integrity. Respondent presented an affidavit from John F. Kiefner, a subject matter expert in the field of pipeline safety and integrity, who stated that hydrostatic test failures alone are not indicative of seam failure susceptibility and that there must be evidence of fatigue-related failures, selected seam corrosion, or other time-dependent defects.[29] Respondent explained it had performed metallurgical analysis of the hydrotest seam failures in 2005–2006 and found no evidence of pressure cycle-induce fatigue, selective seam corrosion, or other time-dependent defects.

Second, OPS argued there were problems with the software program Respondent used because the analysis looked for ductile fatigue even though Respondent's pipe did not have ductile qualities. The brittle seams of the Pegasus ERW pipe, OPS stated, would not experience the same fatigue phenomenon as ductile pipe, and therefore it was not appropriate for Respondent to continue using long seam failure susceptibility determination processes based on the absence of fatigue crack growth. In other words, OPS argued Respondent's conclusion did not properly consider the brittle nature of the pipe and how that affected the ERW pipe's susceptibility to seam failure.

In Response, Respondent explained that it conducted longitudinal seam failure susceptibility analyses in 2004–2005, 2007, 2009, and 2011, using a software program designed to help analyze the pressure cycling for fatigue crack growth. Each analysis showed a safe test interval longer than five years. Respondent therefore concluded the pipe was not susceptible to longitudinal seam failure. The affidavit from Respondent's expert stated that EMPCo's conclusions were reasonable and consistent with available guidance. Even though fatigue had not been previously discovered, Respondent continually evaluated the pipeline to make sure nothing changed from the last analysis.

Finally, with regard to the ILIs that Respondent performed, OPS argued they were not adequate for verifying seam integrity for multiple reasons. OPS cited a study that concluded ILI is not an acceptable substitute for hydrostatic testing when evaluating seam integrity for brittle pipe.[30] OPS noted that Respondent's pipe was brittle, and therefore ILI was not appropriate for evaluating seam integrity on the Pegasus Pipeline.[31]

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[29] Prehearing Submission, Exhibit 1.

[30] Baker Report at 2, stating that "where a low or very low-toughness material is involved . . . hydrostatic testing would give superior assurance . . . if that test was conducted to a sufficiently high level").

[31] OPS explained that "CVN" is a measure of pipe toughness and that a value of CVN under 25 is considered low toughness or brittle. OPS alleged Respondent's pipe had a CVN of 3 to 4.

OPS also contended the types of ILI tools used by Respondent were not adequate for verifying seam integrity because they were incapable of detecting the type of hook crack that eventually caused the pipeline failure. OPS acknowledged that the transverse flux inspection (TFI) tool was appropriate for detecting selective seam corrosion, but argued its usefulness for detecting hook cracks was limited because it could only detect defects of a specific size.[32] Given prior hydrostatic tests were not at a high enough pressure, OPS contended this allowed certain sized defects to go undetected by both the hydrostatic test and ILI.

Respondent countered that nothing in the regulation required a different type of tool, and that the TFI tool was recommended by its tool vendor for seam evaluation. In addition, Respondent contended the point of failure on the pipe was unique and the anomaly was not capable of reliable detection, an opinion shared by Respondent's expert.

In conclusion, Respondent argued that the above processes and methods were appropriately used and fully supported the Company's repeated conclusions that the Pegasus Pipeline was not susceptible to seam failure.

Applicable Safety Standards

Under the integrity management regulations, operators must have a schedule for conducting integrity assessments that is based on all risk factors that reflect the risk conditions on the pipeline.[33] Some of the risk factors that must be considered include results of previous integrity assessments, pipe material, manufacturing, seam type, and leak history.[34]

When considering the pipe material, manufacturing, and seam type, it is necessary for operators to consider the presence of any pre-1970 low-frequency ERW pipe on the system. Pre-1970 ERW pipe is known to exhibit an increased risk of longitudinal seam failure.[35] The seam welds have been found to be susceptible to selective seam corrosion and manufacturing defects such as hook cracks and inadequate bonding that over time can lead to failure.[36] ERW pipe that is "susceptible to longitudinal seam failure" must be subject to periodic reassessments that ensure the integrity of the seam.[37]

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[32] A TFI tool identifies and measures metal loss through the use of a magnetic field wrapping around the circumference of the pipe. The circumferential orientation makes the tool useful for detecting longitudinally-oriented corrosion and defects. "PHMSA Fact Sheet: In-Line Inspections (Smart Pig)," *available at:* https://primis.phmsa.dot.gov/comm/FactSheets/FSSmartPig.htm.

[33] § 195.452(e)(1).

[34] § 195.452(e)(1)(i)–(iii).

[35] In 1988 and 1989, PHMSA issued notices to alert operators of factors contributing to failures of pipelines constructed with ERW pipe. Alert Notice ALN-88-01 (Jan. 28, 1988) and Alert Notice ALN-89-01 (Mar. 8, 1989), *available at:* http://www.phmsa.dot.gov/pipeline/regs/advisory-bulletin.

[36] In a regulation separate from integrity management, PHMSA deemed all pre-1970 ERW pipe to be "susceptible to longitudinal seam failure" unless an engineering analysis proved otherwise. § 195.303(d).

[37] § 195.452(j)(5).

Discussion

The Parties acknowledged that the Pegasus Pipeline is a pipeline that could affect an HCA and that Respondent has prepared an IMP for the pipeline. They also agree that relevant portions of the Pegasus Pipeline were constructed in the 1940s with low-frequency ERW pipe manufactured by Youngstown.

The presence of pre-1970 ERW pipe required Respondent to consider the susceptibility of the pipe to seam failure when prioritizing the pipeline for periodic assessment and determining the appropriate assessment method. The issue presented, therefore, is whether Respondent properly considered the susceptibility of the Pegasus Pipeline to seam failure when establishing an integrity assessment schedule.

In 2005–2006, Respondent conducted a baseline integrity assessment of the pipeline by performing a hydrostatic test.[38] The test resulted in approximately 11 seam failures in the ERW pipe. A metallurgical analysis concluded the seam failures were due to the presence of defects in the pipe, including lack of fusion, hook cracks, and low mechanical strength.[39] The failures were analyzed for evidence of pressure cycling induced fatigue and preferential seam corrosion, but neither condition was detected. Respondent attributed the failures to mill defects and a lower test temperature, which the Company believed caused the seams to be more brittle. Due to the absence of pressure cycling induced fatigue and preferential seam corrosion, Respondent concluded the ERW pipe was not susceptible to seam failure.

PHMSA finds this conclusion was flawed for several reasons. Firstly, in 2004, PHMSA commissioned a study of pre-1970 low-frequency ERW pipe and issues related to assessment methods. The report was issued by Michael Baker Jr. (Baker Report) and provided guidance for determining ERW pipe susceptibility to seam failure.[40] According to the report, operators should consider a host of relevant data when determining seam failure susceptibility, including history of seam failures both in-service and during testing and the causes of those failures.

As noted in the Baker Report, "If a seam-related in-service or hydrostatic test failure has occurred on the segment, the segment is considered susceptible . . . . Although a single failure does not prove the existence of other similar defects, it is reasonable to assume that defects do exist in the seam."[41] Accordingly, the occurrence of seam-related failures during the hydrostatic

[38] Prehearing Submission at 12. Respondent also performed hydrostatic tests in 1969 and 1991.

[39] Prehearing Submission, Exhibit 14 – EMPCo Corsicana to Patoka Hydrotest Summary (Jul. 6, 2006).

[40] *Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*, Final Report (Rev-3), Michael Baker Jr., Inc. (April 2004), *available at:* https://primis.phmsa.dot.gov/iim/techreports.htm.

[41] Baker Report at 20. Respondent pointed to a different passage on page 26 of the report that stated if no fatigue-related failures occurred, it is reasonable to assume the pipe is not susceptible. But PHMSA finds Respondent's interpretation of this sentence in isolation conflicts with other statements in the report. For example, page 25 states a segment could be susceptible even without any seam-related failures. Also as noted above, page 20 states that a segment is considered susceptible if a seam-related in-service or hydrostatic test failure has occurred, without mentioning fatigue.

test of the Pegasus Pipeline in 2005–2006 strongly suggested the ERW pipe was susceptible to seam failure.

The guidance in the Baker Report is generally consistent with an earlier paper by Mr. Kiefner (Respondent's affiant in this case), which OPS included in the record.[42] The Kiefner Paper noted that "[t]o be excluded from a seam-integrity-assessment plan, a segment should exhibit no test breaks when tested to a pressure level of 1.25 times MOP."[43] The paper also noted that to be excluded, a segment must have "no recorded seam-related service failure," unless the failure was entirely explainable as a non-time-dependent event, such accidental overpressuring.[44]

Not only did the Pegasus Pipeline experience approximately 11 seam-related failures during the 2005–2006 hydrostatic test, but the pipeline also experienced seam-related failures during hydrostatic tests in 1991 and 1969.[45] In addition, the pipeline experienced an in-service seam leak in 1984.[46] Given the history of seam-related failures both in-service and during pressure testing of the pipeline, Respondent inappropriately concluded the pipeline was not susceptible to seam failure.

Respondent argued that none of the 2005–2006 test failures exhibited pressure cycling induced fatigue or preferential seam corrosion. Respondent's expert contended that without evidence of such occurrences, "it is reasonable to certify that the hydrostatic test failures are not an indication that the pipeline is susceptible to seam failures."[47]

The evidence supports Respondent's assertion that prior seam failures did not exhibit evidence of fatigue. The failures instead exhibited brittle cracking. Brittle pipe, or pipe with low toughness, is generally less resistant to fracture when stressed compared with more ductile pipe, and therefore will not exhibit the same evidence of fatigue cracking. Respondent acknowledged that its pipeline had low toughness.[48]

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[42] Violation Report, Exhibit D – *Dealing with Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe with Respect to HCA-Related Integrity Assessments*, John F. Kiefner (Feb. 2002) (Kiefner Paper), *available at:* https://primis.phmsa.dot.gov/comm/FactSheets/FSHydrostaticTesting.htm, *also available at*: http://kiefner.com/wp-content/uploads/2013/05/ERW.pdf. *See* Accident Report, Appendix E – Tab A, at ii (noting the "Kiefner Paper formed much of the hazardous liquids industry's basis for the handling of integrity concerns related to pre-70 vintage ERW pipe")

[43] Kiefner Paper at 9.

[44] Kiefner Paper at 7.

[45] Prehearing Submission at 13.

[46] Violation Report, Exhibit G – Leak Report at MP 285.9 (Mar. 9, 1984).

[47] Prehearing Submission, Exhibit 1, at 3.

[48] *See, e.g.*, Post-hearing Brief at 5, fn. 2 (noting prior analyses had confirmed low seam toughness and CVN value of 7). Respondent contended the low toughness may have been due to lower temperature of the test medium, but OPS noted the test temperature was within the range of normal operations.

Although Respondent's expert implied that the brittle cracking on the Pegasus Pipeline was unique, pre-1970 ERW pipe is commonly known to have areas of excessive hardness in the bondline/heat affected zone that exhibit brittle qualities.[49] The Baker Report stated that operators should consider the fracture toughness of the material in determining seam failure susceptibility.[50] By dismissing historical seam failures on the Pegasus Pipeline based solely on the absence of fatigue evidence, Respondent did not properly consider the pipe toughness. Respondent did not properly consider that the absence of fatigue was a result of the low toughness of the pipe.

Subsequent analyses performed by Respondent following the 2005–2006 baseline assessment had the same flaw in that the Respondent failed to properly consider the history of seam-related failures and low toughness of the seam.

In planning for periodic reassessment, Respondent used a program intended to calculate pressure cycle fatigue and reassessment intervals. Respondent concluded each time that the pipeline "had a remaining fatigue life" far in excess of any required reassessment interval.[51] This led Respondent to conclude the pipe was not susceptible to seam failure.

The program relied upon a model for predicting the growth of cracks based on the behavior of ductile pipe through pressure cycles. Due to the brittle nature of Respondent's pipe, however, it was not appropriate for Respondent to base a conclusion regarding seam failure susceptibility on a program that relied upon the behavior of ductile pipe. Even if toughness data was used in the program for calculating reassessment intervals, PHMSA finds it was not reasonable to conclude the pipe was not susceptible to seam failure based upon the prediction of pressure cycling induced fatigue given the history of seam-related failures and the brittle nature of the pipe. Moreover, it did not appear Respondent's use of the program included any consideration of the history of seam failures.

Finally, Respondent performed an ILI integrity reassessment of the pipeline in 2010 using a magnetic flux leakage (MFL) and deformation tool.[52] The use of this type of tool is not suitable for evaluating ERW longitudinal seam integrity due to the orientation of the magnetic field. It was not until 2012–2013 that Respondent finally performed an ILI using a TFI seam/crack tool, which is designed to detect certain ERW seam integrity issues.

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[49] Baker Report at 7–8 (stating a process was sometimes used to "eliminate zones of excessive hardness" in the bondline/heat-affected-zone, and a "stitched bondline is generally characterized by low toughness").

[50] Baker Report at 1.

[51] Prehearing Submission at 14.

[52] An MFL tool uses the same principle as a TFI tool, except the orientation of the magnetic field is not turned 90 degrees like the TFI tool. MFL tools identify and measure metal loss, such as corrosion and gouges. "PHMSA Fact Sheet: In-Line Inspections (Smart Pig)," *available at:* https://primis.phmsa.dot.gov/comm/FactSheets/FSSmartPig.htm.

For the reasons stated above, PHMSA finds Respondent violated § 195.452(e)(1) by failing to properly consider the susceptibility of its ERW pipe to seam failure when establishing a continual integrity assessment schedule based on all risk factors on the Pegasus Pipeline.

Item 2: The Notice alleged Respondent violated 49 C.F.R. § 195.452(j)(3), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—(1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals . . . .
> (3) *Assessment intervals.* An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

The Notice alleged that Respondent violated § 195.452(j)(3) by failing to reassess the Northern Section of the Pegasus Pipeline within five years or 68 months. Specifically, the Notice alleged that in 2005–2006, Respondent performed a baseline assessment of the pipeline using a hydrostatic test, but did not perform a subsequent seam integrity assessment on the Conway to Corsicana segment until an ILI was performed using a TFI tool in 2012–2013. This exceeded the five-year, 68-months interval.

In its written submissions and at the hearing, EMPCo contended that the Patoka to Corsicana segment of the Pegasus Pipeline was subjected to an ILI reassessment in 2010 using caliper and wall loss tools, just four years after the 2006 baseline assessment. Respondent argued that because the company had concluded the pipeline was not susceptible to seam failure, there was no regulatory requirement to perform a seam integrity assessment within five years.[53] Respondent noted, however, that even though it was not required to perform a seam integrity assessment, the Company voluntarily performed an ILI assessment in 2012–2013 using a TFI seam/crack tool.

Applicable Safety Standards

Under the integrity management regulations, operators must have a continual process of periodic reassessment for each pipeline that could affect an HCA.[54] The interval for reassessment of each segment must be based on all applicable risk factors, but may not exceed five years or 68

[53] Post-hearing Brief at 15.

[54] § 195.452(f)(5), (j).

months.[55] The assessment methods available for assessment include ILI and pressure testing, but any method selected to assess the integrity of pre-1970 low-frequency ERW pipe susceptible to longitudinal seam failure must be capable of assessing the integrity of the seam and detecting corrosion and deformation anomalies.[56]

Discussion

The issue that must be decided is whether Respondent was required to perform a reassessment of the Conway to Corsicana segment within five years, or 68 months, using an assessment method capable of assessing the integrity of the ERW pipe seam.

Having already found under Item 1 that the Northern Section of the Pegasus Pipeline should have been considered susceptible to longitudinal seam failure given the history of seam-related failures, the integrity assessments required by the rule must be capable of assessing the integrity of the seam. The hydrostatic test performed in 2005–2006 is a method typically capable of assessing seam integrity, but the next integrity assessment in 2010 using a caliper and wall loss tool was not capable of assessing seam integrity. Respondent did not perform a seam integrity assessment on the Conway to Corsicana segment until 2012–2013 when a TFI seam/crack tool run was performed. Since the assessment of seam integrity was not performed until after the five-year period prescribed in the regulations, Respondent did not comply with § 195.452(j)(3).

Accordingly, PHMSA finds Respondent violated § 195.452(j)(3) by failing to perform a reassessment that included an assessment of seam integrity on the Patoka to Corsicana segment of the Pegasus Pipeline within a period of five years, not to exceed 68 months.

Item 3: The Notice alleged Respondent violated 49 C.F.R. § 195.452(b)(5), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:
> (1) Develop a written integrity management program that addresses the risks on each segment of pipeline . . . .
> (5) Implement and follow the program.
> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—(1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals . . . .
> (4) *Variance from the 5-year intervals in limited situations*—(i) *Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The

[55] § 195.452(j)(3).

[56] § 195.542(c)(1)(i) and (j)(5).

> justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

The Notice alleged that Respondent violated § 195.452(b)(5) by failing to implement and follow provisions of its integrity management program that required notifying OPS when exceeding the five-year assessment interval. The Notice alleged that Section 5 of Respondent's IMP contained procedures for establishing an assessment interval and for justifying a variance from that interval in limited situations. The procedures required, among other things, that Respondent notify OPS of any variance 270 days before the end of the interval.

The Notice alleged that Respondent extended a scheduled seam assessment of the Conway to Corsicana segment of the Pegasus Pipeline on multiple occasions without notifying OPS. Specifically, it alleged the assessment was extended from "prior to 12/31/2011" to "prior to 12/31/2012," and then again from "12/31/2012 to 2/6/2013."[57] The Notice alleged OPS did not receive a notification from Respondent at least 270 days prior to the end of the interval.

In its written submissions and at the hearing, Respondent argued that because the Company had concluded the pipeline was not susceptible to seam failure, there was no specific requirement to perform a seam integrity assessment within five years or 68 months. When Respondent performed an ILI reassessment in 2010 using caliper and wall loss tools, it was within the five-year period and no variance was required. Likewise, the Company contended that when it performed a seam assessment using a TFI seam/crack tool in 2012–2013, it was a "discretionary" assessment rather than required under the regulation.[58] Therefore, Respondent contended, extending the schedule for the tool run did not require a variance or notification to OPS.

Applicable Safety Standards

Section 195.452(b) requires pipeline operators to develop, implement, and follow a written integrity management program that includes a continual process of reassessment.[59] The interval for reassessment of each pipeline segment must be based on all applicable risk factors, but may not exceed five years or 68 months.[60] In limited situations, an operator may be able to justify an assessment interval that is longer than five years, but the operator must notify OPS of the justification for a variance and the notification must be received no later than 270 days prior to

[57] Notice at 4.

[58] Prehearing Submission at 17.

[59] § 195.452(f)(5), (j).

[60] § 195.452(j)(3).

the end of the five-year (or less) interval.[61] The justification for a variance must be supported by a reliable engineering evaluation combined with the interim use of another technology that provides an equivalent understanding of the condition of the pipe.[62]

Respondent's IMP contained provisions for notifying OPS of the justification for a variance.[63] Section 4.4.1.1 stated that "The operator must notify PHMSA at least 270 days prior to the end of a five-year interval to request a longer reassessment interval. The operator must send a notice to PHMSA that states the proposed alternative interval schedule and the engineering reasons for the requested schedule change."

Discussion

The issue is whether these procedures required Respondent to notify OPS when the Company exceeded a period of five years for performing a seam integrity reassessment of its ERW pipe.

As noted above in Item 2, Respondent was required to perform a reassessment of its pre-1970 low frequency ERW pipe within five years of the 2006 baseline using a method capable of assessing the integrity of the seam.[64] It follows that under § 195.452(j)(4)(i), a variance and notification to OPS is required if the reassessment is scheduled beyond the maximum five-year time period.

EMPCo originally had scheduled the TFI seam integrity assessment "prior to 12/31/2011," which would have been before expiration of the 5-year interval.[65] Respondent then extended the schedule from "prior to 12/31/2011" to "prior to 12/31/2012," and extended it again from "12/31/2012 to 2/6/2013."[66] Under its IMP procedures, Respondent was required to notify OPS of the proposed alternative schedule and the engineering reasons for the requested change no later than 270 days prior to the end of the five-year interval. Respondent did not provide notification of the variance to OPS.

While Respondent argued that it did not violate its procedures because the TFI tool run was "discretionary," PHMSA finds the seam integrity assessment was not optional, but required under the regulation. The extension of the period to perform the assessment beyond five years from the last seam integrity assessment required a variance under the regulation. Since Respondent did not notify OPS of the multiple extensions of time for performing the TFI seam/crack tool assessment as specified in its procedures, Respondent did not comply with its procedures or with § 195.452(b)(5) and (j)(4)(i).

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[61] § 195.452(j)(4).

[62] § 195.452(j)(4).

[63] Prehearing Submission, Exhibit 4 – EMPCo IMP Manual Excerpts, Sections 4.4, 5.1(4), 5.4 (2012).

[64] § 195.452(j)(3).

[65] Notice at 4.

[66] Notice at 4.

Accordingly, PHMSA finds Respondent violated § 195.452(b)(5) by failing to implement and follow its IMP procedures for a variance, including the procedures requiring notification to OPS.

Item 4: The Notice alleged Respondent violated 49 C.F.R. § 195.452(e)(1), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (*see* paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment . . . .
> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—(1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area . . . .
> (3) *Assessment intervals.* An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

The Notice alleged that Respondent violated § 195.452(e)(1) by failing to establish an assessment schedule that prioritized segments for assessment based on all risk factors that reflect risk conditions on the pipeline. Specifically, the Notice alleged that Respondent failed to prioritize the Conway to Corsicana segment for reassessment. Respondent performed a TFI tool seam integrity assessment on the Patoka to Conway segment in 2010, but did not perform the same assessment on the Conway to Corsicana segment, where the Mayflower Accident occurred, until 2012-2013. The Notice alleged this segment had more hydrostatic test failures in 2005–2006 than the Patoka to Conway segment, had all the seam failures during the 1991 hydrostatic test, experienced an in-service ERW seam leak, and had more miles of pre-1970 ERW pipe manufactured by Youngstown. For these reasons and several others, the Notice alleged that it was inappropriate for Respondent to schedule and perform a seam integrity assessment with a TFI tool on the Patoka to Conway segment before the Conway to Corsicana segment.

In its written submissions and at the hearing, Respondent stated that the ERW pipe was not determined to be susceptible to seam failure, and therefore the Company was not required to perform a seam integrity assessment using a TFI seam/crack tool. Since the TFI tool run that it performed was voluntary, EMPCo reasoned there was no requirement to prioritize one segment differently than another.

Respondent also contended that the Patoka to Conway segment was correctly prioritized over the Conway to Corsicana segment. Respondent maintained there were an equal number of failures on both segments during the 2005–2006 hydrostatic test, and there were actually more hydrostatic seam failures "on a LF-ERW per mile basis" on the Patoka to Conway segment than the Conway to Corsicana segment.[67] In addition, there were more pressure reversals on the Patoka to Conway segment, shorter theoretical fatigue life, and a number of girth weld failures not present on the Conway to Corsicana segment.

Applicable Safety Standards

Under the integrity management regulations, operators must have a continual process of periodic reassessment for each pipeline that could affect an HCA.[68] Pipeline segments must be prioritized for assessment based on a schedule that reflects the risk conditions on the pipeline.[69] Factors that must be considered in the scheduling of assessments include, but are not limited to: results of previous integrity assessments, pipe material, manufacturing, seam type, and leak history.[70]

Discussion

The issue presented is whether Respondent had appropriately prioritized segments for assessment on the Pegasus Pipeline when it performed a seam integrity assessment of the Patoka to Conway segment before the Conway to Corsicana segment.

The evidence demonstrates the Northern Section of the Pegasus Pipeline is approximately 648 miles long and runs from Patoka to Conway to Corsicana. The Patoka to Conway segment is approximately 318 miles. Roughly 36% of the segment (116 miles) is pre-1970 low frequency ERW pipe manufactured by Youngstown. The Conway to Corsicana segment is approximately 330 miles. Roughly 90% of the segment (299 miles) is pre-1970 low frequency ERW pipe manufactured by Youngstown.

In 1969, EMPCo conducted a hydrostatic test of the Northern Section. There was one seam failure during the test, which occurred on the Conway to Corsicana segment. No seam failures were reported on the Patoka to Conway segment. In 1984, the Conway to Corsicana segment experienced an in-service seam-related leak.[71] A second hydrostatic test was performed in 1991. Three seam failures occurred during that test, all on the Conway to Corsicana segment. No seam failures were reported on the Patoka to Conway segment.

In 2005–2006, Respondent performed a third hydrostatic test of the Northern Section. The test was performed in multiple sections, starting first with test sections in the Patoka to Conway

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[67] Prehearing Submission at 18.

[68] § 195.452(f)(5), (j).

[69] § 195.452(e)(1).

[70] § 195.452(e)(1)(i)–(iii).

[71] Violation Report, Exhibit G – Leak Report at MP 285.9 (Mar. 9, 1984).

segment. After four seam failures occurred during the first test sections, a lower test pressure was used to complete testing. A total of five failures occurred on the Patoka to Conway segment, and all of the failures occurred at a test pressure that was higher than the segment had previously been tested in 1991.[72] When the Conway to Corsicana segment was subsequently pressure tested, there were six seam failures. All of the failures occurred at pressures close to or lower than the test pressure in 1991.[73]

When the number of hydrostatic test and in-service seam failures from 1969 to 2006 are considered in total, the Conway to Corsicana segment experienced eleven seam failures while the Patoka to Conway segment experienced five. The failures on the Conway to Corsicana segment were higher in number and occurred at lower test pressures, demonstrating the segment had a higher incidence of seam failure. The Conway to Corsicana segment also had significantly more ERW pipe, both in terms of mileage and percentage of the whole segment. These basic facts demonstrate the Conway to Corsicana segment had a higher risk of seam failure and should have been prioritized for seam integrity reassessment over the Patoka to Conway segment.

While Respondent argued the TFI tool run was voluntary and was not required to be prioritized, PHMSA determined in Items 1 and 2 of this Order that the ERW pipe should have been considered susceptible to longitudinal seam failure, and that Respondent was required to perform a reassessment of the pipeline using a method capable of assessing seam integrity. Under § 195.452(e), Respondent was required to establish an integrity assessment schedule that prioritized pipeline segments for continual assessments.

Respondent argued that the segments were correctly prioritized because more hydrostatic test seam failures had occurred on the Patoka to Conway segment "on a LF-ERW per mile basis." PHMSA finds the relevance of this calculation to overall segment risk is questionable. For example, despite there being more than double the amount of higher risk ERW pipe on the Conway to Corsicana segment, the more ERW mileage counter-intuitively *lowered* the risk of the segment on a leaks per ERW-mile basis. It also appears that Respondent's calculation inexplicably excluded from consideration any test seam failures or in-service seam leaks prior to 2005, all of which occurred on the Conway to Corsicana segment.

Respondent also claimed there were additional reasons to prioritize the Patoka to Conway segment, such as the occurrence of more pressure reversals on the segment. PHMSA cannot find where the record shows more pressure reversals occurred on the Patoka to Conway segment. More importantly, no evidence was cited that demonstrates such information was considered when Respondent prioritized the assessments. Likewise, PHMSA cannot find evidence in the record that demonstrates Respondent based its decision on theoretical fatigue life or number of girth weld failures.

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[72] Prehearing Submission, Exhibit 14 – EMPCo Corsicana to Patoka Hydrotest Summary (Jul. 6, 2006). The failures occurred at pressures that were 75 psig to 199 psig higher than 1991 test pressures.

[73] The failures occurred at pressures that were 28 psig lower to 8 psig higher than 1991 test pressures.

Given that the Conway to Corsicana segment had more than twice the amount of ERW pipe than the similarly sized Patoka to Conway segment, and the Conway to Corsicana segment had a higher incidence of seam failure, PHMSA finds Respondent's decision to prioritize the Patoka to Conway segment for a seam assessment in 2010 and to delay assessment of the Conway to Corsicana segment until 2012-2013 was not appropriately based on all risk factors that reflect the susceptibility of the segments to seam failure.

Accordingly, PHMSA finds Respondent violated § 195.452(e)(1) by failing to establish a schedule for continual integrity assessment that prioritized the segments for reassessment based on the risk conditions on the segments.

Item 5: The Notice alleged Respondent violated 49 C.F.R. § 195.452(h)(1), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (h) *What actions must an operator take to address integrity issues?*— (1) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity . . . .
> (4) *Special requirements for scheduling remediation*—(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions . . . .

The Notice alleged that Respondent violated § 195.452(h)(1) by failing to take prompt action to address conditions discovered through an integrity assessment. Specifically, the Notice alleged that following an integrity assessment, Respondent received preliminary reports that identified immediate repair conditions on the Pegasus Pipeline, but failed to address those conditions promptly. Two examples of immediate repair conditions were noted at Mile Point (MP) 164.051 and MP 142.394, allegedly identified in a report dated August 9, 2010.

In its written submissions and at the hearing, Respondent argued that both instances were repaired in a timely manner. Respondent explained the first one at MP 164.051 was a 72% metal loss anomaly that EMPCo first learned of in a preliminary report received August 23, 2010. Although the vendor dated the report August 9, 2010, the information was not provided to EMPCo until August 23, 2010. EMPCo stated that it considered the anomaly a "potential immediate" repair the same day it received the report and repaired the condition just five days later.[74] The second example at MP 142.394 was a 0.74% topside dent with an external corrosion pit that EMPCo learned about when it received the final report on January 10, 2011. EMPCo claimed it acted to repair that anomaly within two days of receiving the final report.

[74] Post-hearing Brief at 8.

At the hearing, OPS asserted that even if EMPCo discovered the conditions on the same day the reports were received, Respondent did not comply with the code requirement to take prompt action because the Company failed to take an immediate pressure reduction or shut down the pipeline until the operator repaired the conditions.

Applicable Safety Standards

Section 195.452(h)(1) requires pipeline operators to take "prompt action" to address any anomalous conditions that is discovered as a result of an integrity assessment. Discovery of a condition occurs when the operator has adequate information about the condition to determine that the condition presents a potential threat to integrity.[75] Conditions must be addressed according to a schedule that prioritizes the conditions for remediation.[76] Certain conditions must be treated as "immediate repair conditions."

Anomalies that must be treated as immediate repair conditions include metal loss of greater than 80% wall thickness, and a topside dent with any indication of metal loss.[77] When determining if a detected anomaly meets the criteria for immediate repair, ILI tool tolerances should be considered to assure defects are properly identified.[78]

When an immediate repair condition is discovered, an operator must take prompt action to address the condition, which includes repairing the condition as soon as practicable and temporarily reducing operating pressure or shutting down the pipeline until the repair is completed.[79] The pressure reduction must be taken as soon as safety allows. Operators may not wait several days to reduce pressure.[80]

Discussion

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[75] § 195.452(h)(2).

[76] § 195.452(h)(3).

[77] § 195.452(h)(4)(i)(A)–(C).

[78] *See* PHMSA IMP Guidance *FAQ 7.19 – Should tool tolerance be considered when determining if a detected anomaly meets repair criteria?* (stating that tool tolerances should be used to assure that defects requiring early excavation and mitigative action are properly identified and characterized).

[79] § 195.452(h)(1), (h)(4)(i). *See also*, PHMSA IMP Guidance *FAQ 7.4 – What is an "immediate repair condition"?* (stating that repairs must be made as soon as practicable. Pressure must also be reduced as soon as safety allows and the pipeline must be operated at or below that pressure until the repair is made). PHMSA publishes answers to frequently asked questions concerning compliance with the integrity management regulations on its website, *available at:* http://primis.phmsa.dot.gov/iim.

[80] *See, e.g.*, Spectra Energy Transmission, LLC, CPF No. 3-2013-1006, Item 3, 2014 WL 5824269, at *5 (Sept. 22, 2014) (finding a reduction taken three to four days after discovery of an immediate repair condition did not comply with the gas IMP requirement; rejecting the operator's claim that it had five days to determine if it could repair the condition before reducing pressure); Southern Natural Gas Co., CPF No. 4-2011-1011M, Item 7, 2013 WL 6146122, at *5 (Sept. 20, 2013) (finding an operator's IMP procedures were inadequate because they permitted five days from discovery of an immediate repair condition before taking a pressure reduction).

The issue that must be decided is whether Respondent took prompt action to address immediate repair conditions discovered on the Pegasus Pipeline following an integrity assessment in 2010.

The evidence demonstrates that in 2010, EMPCo hired a vendor to perform an ILI integrity assessment of the Pegasus Pipeline. The Conway to Corsicana segment was tested as part of the assessment. On August 23, 2010, the vendor provided EMPCo with a preliminary report of the ILI results.[81] The preliminary report identified an anomalous condition at MP 162.051, but did not flag it as an immediate repair condition because it was estimated to be a 72% wall loss anomaly, which is less than the 80% threshold in the code for an immediate repair. EMPCo factored in the tool tolerance the day the report was received and declared the anomaly an immediate repair condition.

In its written submissions Respondent occasionally referred to this condition as a "potential immediate," implying that the Company may not have actually declared the anomaly an immediate repair condition.[82]

The regulation does not recognize the terminology "potential immediate." Respondent had adequate information about the condition to make a determination that the anomaly was an immediate repair condition when factoring in tool tolerance. Even if Respondent's classification was a conservative estimate, the Company was required to address the anomaly as an immediate repair condition based on that estimate.[83] Moreover, at the hearing EMPCo repeatedly stated that it had declared the anomaly an immediate repair condition.[84] As such, EMPCo was required to treat the condition as an immediate repair condition.

Respondent repaired the condition five days later on August 28, 2010. Although the immediate repair condition was repaired within five days, the pipeline safety regulations also required that Respondent take prompt action by reducing operating pressure or shutting down the pipeline prior to completing the repair. EMPCo failed to demonstrate this was performed. At the hearing, when asked if the Company could provide documentation as to whether or not a pressure reduction or shut down was performed, EMPCo did not indicate that such documentation could be provided. PHMSA finds no evidence in the record that Respondent took a temporary pressure reduction prior to completing the repair five days later.

A similar finding is made with regard to the condition at MP 142.394. This immediate repair condition was identified by the vendor in its final report received on January 10, 2011. The

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[81] Although there was confusion at the hearing about when EMPCo received this report, I find the evidence supports EMPCO's claim that it was received on August 23, 2010.

[82] Post-hearing Brief at 8.

[83] *See, e.g.*, Alyeska Pipeline Service Co., CPF 5-2006-5018, Item 2, 2010 WL 6500066, at *4 (Jan. 13, 2010) (finding an anomaly must be treated as an immediate repair condition once the operator determines it could meet the immediate repair criteria, even if the operator's determination was a conservative estimate based on information in addition to ILI data.)

[84] Hearing Transcript at 14, 24, 27, 28 and 32.

anomaly was identified as a topside dent with external corrosion. Respondent determined the anomaly was an immediate repair condition upon receipt of the report and immediately scheduled the repair, which was completed two days later on January 12, 2011.[85] While the repair was completed in two days, there is no evidence that Respondent took a temporary pressure reduction prior to completing the repair.

Evidence of a third anomaly was included in the record. Although evidence of this anomaly was incorrectly referenced in the Violation Report as MP 142.394, Respondent explained that the evidence actually concerned an anomaly at MP 274.09. This condition was identified in the final report received January 10, 2011. Respondent discovered the condition the same day the report was received, and repaired the condition three days later on January 13, 2011.[86] There is no evidence in the record that EMPCo took a pressure reduction or shut down the pipeline between the discovery of this condition and the date the condition was repaired.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.452(h)(1) by failing to take prompt action to address anomalous conditions by temporarily reducing operating pressure or shutting down the pipeline until immediate repairs were completed.

Item 6: The Notice alleged Respondent violated 49 C.F.R. § 195.452(h)(2), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (h) *What actions must an operator take to address integrity issues?*— (1) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis . . . .
> (2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

The Notice alleged that Respondent violated § 195.452(h)(2) by failing to promptly discover the condition of the Pegasus Pipeline within 180 days of an integrity assessment. The Notice listed four integrity assessments that were conducted on the Northern Section from Patoka to Corsicana between 2010 and 2013, for which Respondent allegedly failed to promptly discover conditions

[85] Post-hearing Brief at 9.

[86] EMPCo argued that any discussion of MP 274.09 is irrelevant because that location was not specifically mentioned in the Notice. I find, however, that evidence regarding MP 274.09 was part of the record and that the other conditions listed in the Notice were referred to as "examples." The discrepancy was clarified by the Parties during the hearing, and EMPCo had an opportunity (and did) address MP 274.09 at the hearing and in its written submissions. There is no prejudice by considering this evidence.

until weeks or months after the 180-day deadline. At the hearing, OPS explained that EMPCo had decided to combine four testable segments into two testable segments prior to performing the integrity assessments. The length of the newly created larger testable segments, OPS alleged, exceeded the ability of the tool vendor to produce timely assessment data.

At the hearing and in its written submissions, EMPCo did not contest the allegation that discovery was made beyond 180 days after the assessments, but noted that the regulation permits exceeding 180 days if the "operator can demonstrate that the 180-day period is impracticable."[87] For each of the four assessments referenced in the Notice, EMPCo explained that the ILI tool vendor did not produce inspection data until nearly the conclusion of the 180-day period. Since the Company's IMP procedures required verification and integration of the ILI vendor data upon receipt, EMPCo explained that it did not have sufficient information to declare discovery within the deadline. Thus, Respondent argued, it was impracticable to meet the 180-day period given the vendor's delay, and the Company was justified to extend the discovery period in accordance with its procedures and the regulation.

Respondent further noted that PHMSA has acknowledged that in some situations, a delay in receiving ILI results could render the discovery period impracticable."[88] Respondent also contended the IMP regulations place no limit on the distance of a tool run, and that vendor timeliness is an issue industry-wide regardless of the length of a segment. Respondent noted that for each tool run, the vendor committed to provide the data well in advance of the deadline.[89]

Applicable Safety Standards

One of the core components of the integrity management regulations is the requirement to carry out integrity assessments and to identify and repair conditions discovered as a result of the assessment.[90] Following an integrity assessment, an operator must promptly obtain adequate information about conditions on the pipeline. The information must be obtained by the operator no later than 180 days after an integrity assessment, unless the operator can demonstrate the 180-day period is impracticable.[91]

Discussion

Respondent acknowledged that discovery in these instances was later than 180 days. Therefore, the only remaining issue to be decided is whether it was impracticable for Respondent to discover the conditions within the 180-day period.

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[87] § 195.452(h)(2).

[88] Post-hearing Brief, Exhibit 78 – ExxonMobil Pipeline Co., CPF 4-2011-5016, Item 2, 2013 WL 4478404, at *14 (June 27, 2013).

[89] Post-hearing Brief at 10.

[90] § 195.452(f), (h).

[91] § 195.452(h)(2).

The record shows that in 2005–2006, EMPCo performed baseline assessments of the Northern Section of the Pegasus pipeline using hydrostatic tests. At the time, the Northern Section was divided into four testable segments that were each between 142 miles and 175 miles in length. In the intervening years between the baseline assessment and reassessment, EMPCo decided to combine the testable segments. The Patoka to Doniphan and Doniphan to Conway segments were combined into one testable segment from Patoka to Conway spanning approximately 318 miles in length. EMPCo combined the Conway to Foreman and Foreman to Corsicana segments into a single testable segment from Conway to Corsicana that was approximately 330 miles in length.

While EMPCo correctly noted there is no rule expressly prohibiting the length of these testable segments, PHMSA finds the 180-day discovery deadline does place some practical limits on the amount of data that can be reasonably gathered and evaluated within the prescribed time period. Operators are under an obligation to ensure their integrity assessments are planned in a manner that will ensure discovery no later than 180 days after the assessment. The assumption of risk in not meeting the 180-day deadline lies with the operator.

In a prior enforcement action, PHMSA stated that "in some situations, a delay in receiving ILI results from a tool vendor may render the 180-day discovery period impracticable."[92] Although it is possible for such a situation to arise, generally it is not an impracticability where the vendor delay could have been anticipated ahead of time, or where there was some action by the operator that contributed to the delay.

In this case, EMPCo planned tool runs that spanned over 300 miles each, thereby increasing the amount of information needed to be processed and reported. There is evidence that the tool vendor informed Respondent before the Conway to Corsicana assessment that for such a distance, it would normally take 258 days to finalize a report, far exceeding the regulatory deadline. Later, the vendor stated that it would be able to complete the report in 140 days.[93] At Respondent's urging, the vendor then agreed to 120 days. Although the vendor committed to having the information to Respondent in a sufficient amount of time, Respondent had notice that timing was at least a potential issue due to the size of the testable segment.

While Respondent believed the information would be received on time, PHMSA finds the delay was influenced by the amount of information that had to be collected, processed, and reported for the sizable testable segments. As the operator of the pipeline facility, Respondent bore the risk that the size of its testable segments could result in longer processing times that would impact compliance with the 180-day discovery period. Since PHMSA finds the actions of Respondent contributed to the delay in receiving ILI information following the tool run. PHMSA finds impracticability does not exist in this instance.

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[92] ExxonMobil Pipeline Co., CPF 4-2011-5016, Item 2, 2013 WL 4478404, at *14 (June 27, 2013).

[93] Post-hearing Brief, Exhibit 64 – email dated April 11, 2012, from tool vendor to Respondent indicating a report could not be finalized within 90 days as Respondent would normally require due to the length of the segment. Under the vendor proposal, it would take 258 days, but actually it could be done in 140 days. The reply from Respondent requested the final be received no later than 120 days, to which the vendor indicated that would be possible.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.452(h)(2) by failing to obtain sufficient information about conditions on its pipeline within 180 days following an integrity assessment.

Item 7: The Notice alleged Respondent violated 49 C.F.R. § 195.452(b)(5), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:
> (1) Develop a written integrity management program that addresses the risks on each segment of pipeline . . . .
> (5) Implement and follow the program.
> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—(1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.
> (2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

The Notice alleged that Respondent violated § 195.452(b)(5) by failing to implement and follow provisions of its IMP related to periodic evaluation. The Notice alleged that Respondent's IMP required risk assessments to be updated as changes occur. The Notice alleged Respondent did not follow these procedures when it extended the timing of a TFI tool run on the Conway to Corsicana segment of the Pegasus Pipeline from 2011 to 2013 without revising risk analyses that relied upon the inspection having been performed. The Notice alleged that Respondent's failure to identify changes to potential threats caused integrity decisions to rely upon incorrect information, which in turn affected decisions about appropriate risk reduction activities like preventative and mitigative measures.

In its written submissions and at the hearing, Respondent contended that its procedures for updating risk assessments did not apply in this instance. Respondent explained that in March 2011, the Company conducted a long seam failure susceptibility analysis that determined the Conway to Corsicana segment was not susceptible to seam failure. Since there was no requirement to run a TFI tool after March 2011, and no other changes to integrity conditions took place, Respondent contended that revisions to its risk analysis was not required. Respondent also noted that the TFI tool run in 2013 did not detect an anomaly on the pipeline at the point of the

Mayflower Accident, so the defect at that location would have been even smaller and less detectable had the tool been run earlier.

At the hearing, OPS clarified that this alleged violation does not concern whether or not the anomaly could have been detected, but rather it concerns Respondent's failure to update the risk model.

Applicable Safety Standards

Section 195.452(b) requires pipeline operators to develop, implement, and follow a written IMP. The program must include, among other things, a continual process of assessment and evaluation to maintain a pipeline's integrity.[94] Respondent's IMP contained procedures for continual assessment and evaluation. The relevant procedures were at section 5.4 of the IMP and element 2 of the Operations Integrity Management System (OIMS).[95]

Section 5.4 of the IMP states, in part: "The primary source of Continual Evaluation and Assessment is the OIMS 2A process . . . . OIMS 2A now requires an annual review of every active testable pipeline segment. The purpose of this review is to identify changed conditions or new threats to the pipeline integrity."[96] The procedure states further that "As part of this annual review, each [local risk management team] will determine if an updated risk assessment is required based upon their review of the pipeline system." Element 2 of the OIMS states, in part, that "Risk assessments are updated at specified intervals and as changes occur."[97]

Discussion

The issue to be determined is whether these procedures required Respondent to update its risk analyses when the Company delayed performance of a TFI tool run on the Conway to Corsicana segment of the Pegasus Pipeline.

Under Items 1 and 2 of this Order, PHMSA found that Respondent's ERW pipe should have been considered susceptible to longitudinal seam failure, and that a timely assessment of the pipeline was required under the regulations using a method capable of assessing seam integrity. A significant delay in performing a required integrity assessment constitutes a change that could affect the risk assessment of the pipeline.

Respondent had initially planned to perform a seam assessment of the Conway to Corsicana segment in 2011 using a TFI tool. When Respondent performed a risk assessment in 2011, Respondent indicated that the tool run had already been performed, because the operator planned to complete the tool run that year. The tool run was actually delayed until 2012 and then delayed to 2013.

94 § 195.452(f)(5), (j).

95 Prehearing Submission at 21.

96 Prehearing Submission, Exhibit 4 – EMPCo IMP Manual Section 5.4 (2012).

97 Prehearing Submission, Exhibit 5 – EMPCo OIMS Framework, Elements 2.4 (2009).

Since the results of the 2011 risk assessment were based on a tool having been run, and the tool run was subsequently delayed, at a minimum, Respondent's procedures required a review that identified this delay as a changed condition. The procedures also required a determination as to whether an updated risk assessment was required due to this change. There is no evidence in the record that such an evaluation took place or that the risk assessment was updated to reflect this change.

Respondent's argument that the procedures did not require updating the risk analysis because the Company had determined the pipeline was not susceptible to seam failure must be rejected. PHMSA has already determined there was a legal requirement to perform a seam integrity assessment of the pipeline.

PHMSA also rejects Respondent's argument that the procedures did not apply because running the TFI tool earlier would not have detected the anomaly at the location of the accident. PHMSA does not find this claim made after the fact excuses the failure to evaluate the effect of the delay on the risk assessment.

For these reasons, I find EMPCo violated 49 C.F.R. § 195.452(b)(5) by failing to follow provisions of its IMP related to periodic evaluation when it extended the timing of a TFI tool run without evaluating the effect on the applicable risk assessment.

Item 8: The Notice alleged Respondent violated 49 C.F.R. § 195.402(a), which states:

> **§ 195.402 Procedural manual for operations, maintenance, and emergencies.**
> (a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies . . . .

The Notice alleged that Respondent violated § 195.402(a) by failing to follow its manual of written procedures for conducting operations and maintenance activities. Specifically, the Notice alleged that Respondent did not follow procedures for using the Threat Identification and Risk Assessment (TIARA) program when assessing risk on the Conway to Foreman segment of the Pegasus Pipeline.

At the hearing, OPS explained that Respondent's TIARA program works by inputting data through a series of questions. In 2011, Respondent used the program to assess risk on the Conway to Foreman segment. One of the questions was whether or not a TFI tool run had been performed. Respondent answered Yes, because it planned to run a TFI tool in a few months. The tool run, however, was delayed a year; then it was delayed another year. OPS contended that Respondent never went back and updated the TIARA program to indicate that the TFI tool had not been run. This resulted, OPS alleged, in the elimination of identified threats that would have been identified had Respondent correctly answered the question. When the identified threats were artificially eliminated by the program, the preventative and mitigative measures that would have been required were also eliminated. Therefore, according to OPS, Respondent's failure to follow procedures for the TIARA program resulted in an inaccurate risk assessment and the absence of required preventative and mitigative measures.

In its response and at the hearing, EMPCo argued that this alleged violation was "erroneously pleaded as a matter of law" and should be withdrawn.[98] Specifically, Respondent noted that the Notice cited a violation of § 195.402(a), a regulation requiring operators to follow their operations and maintenance (O&M) procedures. Respondent argued that its TIARA program is not part of the Company's O&M procedures, but is rather part of the Company's IMP subject to § 195.452.

Respondent also contested the alleged violation on grounds that EMPCo did comply with its procedures for using TIARA. Respondent acknowledged the 2011 risk assessment did not result in any identified threats, but EMPCo had nevertheless decided to implement preventative and mitigative measures, including three emergency flow restricting devices (EFRDs) and running a TFI seam/crack tool.

Applicable Safety Standards

The pipeline safety standards applicable for pipelines used in the transportation of hazardous liquids are codified at 49 C.F.R. Part 195. Among these requirements, Part 195, Subpart F, prescribes the minimum requirements for operations and maintenance, including § 195.402(a), which tells operators they must "prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities . . . ."

Section 195.402(c) tells operators what minimum procedures are required in their O&M manuals. Of importance here, § 195.402(c)(3) states that O&M manuals must include procedures for "operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part."

The "subpart" referenced in § 195.402(c)(3) is Subpart F, in its entirety. Subpart F includes the integrity management program requirements found in § 195.452, including the aforementioned § 195.452(b), which requires operators to develop and follow a written integrity management program. By its plain language, the requirements in § 195.402(c)(3) encompass those found in § 195.452. While it would have been more precise to cite § 195.452(b)(5), which requires operators to "implement and follow [their IMP] program," there is no legal deficiency in the citation of § 195.402(a) for this alleged violation.

Discussion

With regard to whether Respondent followed its procedures, the evidence demonstrates EMPCo's written IMP provides for the use of the TIARA program in the risk management process. The program requires EMPCo to manually enter information and other data in response

[98] Post-hearing Brief at 10.

to certain questions. One of the questions is: "Has a ILI crack tool (TFI or UT) been successfully run and have the appropriate repairs been scheduled?"[99]

As acknowledged at the hearing by both parties, EMPCo personnel answered this question Yes in March 2011 for the Conway to Foreman segment of the Pegasus Pipeline. As explained by EMPCo, the decision to answer Yes was based on a belief that EMPCo would be performing a TFI tool assessment in a couple of months. The ILI assessment was delayed, however, for approximately two years. EMPCo never revisited the question and answer.

The parties discussed at length at the hearing the impacts of the Yes answer, but the primary issue is whether answering Yes was an accurate statement that complied with Respondent's procedures for use of the TIARA program. The question "Has a ILI crack tool (TFI or UT) been successfully run . . . ." was straight-forward and did not have any qualifying language asking if a tool run was planned for the future. The question asked only if the tool run had already occurred. The question also asked if repairs had been scheduled. In other words, the TIARA program needed to know if the current integrity of the pipeline had been assessed and verified.

By answering this question in the affirmative, Respondent misrepresented the current status of integrity verification on the pipeline. The answer did not accurately reflect the fact that the tool had not been run and no repairs had been scheduled. The issue was then compounded when the tool run became delayed for two years. As a result, EMPCo failed to properly adhere to the procedures as written.

Respondent's failure to follow its procedures constituted a violation of both §§ 195.402(a) and 195.452(b)(5). PHMSA finds citation to § 195.452(b)(5) is more precise in this instance because, as Respondent noted, the procedures at issue were part of Respondent's IMP.

Accordingly, I find EMPCo violated 49 C.F.R. § 195.452(b)(5) by failing to follow its written procedures for the TIARA program by incorrectly indicating that a TFI tool run had been performed and then failing to correct it when the tool run was delayed.

Item 9: The Notice alleged Respondent violated 49 C.F.R. § 195.452(b)(5), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:
> (1) Develop a written integrity management program that addresses the risks on each segment of pipeline . . . .
> (5) Implement and follow the program.
> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—(1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line

[99] Prehearing Submission, Exhibit 28 – EMPCo TIARA UDT Q&A Conway to Corsicana, at 19 (2011).

pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.

The Notice alleged that Respondent violated § 195.452(b)(5) by failing to implement and follow provisions of its IMP related to management of change (MOC). Specifically, the Notice alleged that Respondent failed to follow its procedures for MOC when it merged four testable segments into two segments on the Pegasus Pipeline. As discussed above in Item 6, there were previously four identified segments on the Northern Section of the Pegasus Pipeline from Patoka to Corsicana. The Notice alleged that when Respondent combined the four segments into two testable segments, the Company failed to create MOC documentation as required by its IMP. The newly created testable segments, the Notice alleged, impacted the Company's TIARA risk assessments by diluting risk scores of higher threat segments, such as the Lake Maumelle Watershed and Mayflower populated areas.

In its written submissions and at the hearing, Respondent explained that its IMP ensures operational, procedural, and physical changes are safely implemented. In accordance with those procedures, Respondent stated that it completed MOC forms in 2005 that "expressly considered the impact of the merger" of testable segments.[100] Respondent submitted copies of the MOC forms and explained that the Company concluded in 2005 that there would be no negative impact to IMP risk assessments as a result of the merger.[101] Respondent contested the assertion in the Notice that the merger of testable segments impacted risk assessments, because the TIARA dynamic risk segmentation does not permit aggregation or masking of threats.[102]

Applicable Safety Standards and Discussion

Section 195.452(b) requires pipeline operators to develop, implement, and follow their written integrity management program. The issue here is whether Respondent followed its IMP procedures by creating MOC documentation when it merged four testable segments on the Northern Section of the Pegasus Pipeline.[103] Although other issues were discussed at the hearing, such as the impacts of the merger, I review the record only to determine whether Respondent complied with its procedures.[104]

Respondent offered two forms to demonstrate MOC was documented for the merging of testable segments. The first form is MOC 2829, dated August 10, 2005, titled *CCGC – Doniphan Station*

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[100] Prehearing Submission at 22, *citing* Exhibit 5 – EMPCo Operations IM System procedure Element 7.2.

[101] Prehearing Submission, Exhibits 10 and 11 – MOC Forms 05-2829 and 05-2833 (Aug. 10, 2005).

[102] Prehearing Submission at 23.

[103] *See, e.g.*, Hearing Transcript at 69 and 74 (OPS explaining that notwithstanding the alleged negative impact of the merger, "the basis of the allegation . . . is the operator failed to follow its own procedures.")

[104] There was also disagreement at the hearing about whether the testable segments were merged in 2005, as claimed by Respondent, or in 2009 as claimed by OPS. Given the finding of violation, it is not necessary to resolve this particular disagreement.

Reversal.[105] The reason for the change addressed in the form is an "Opportunity to reverse and reactivate idle pipeline in order to transport Canadian crude to the Gulf Coast." In reviewing the documentation, I find nowhere in the form or accompanying communications any relevant discussion or analysis of the merger of testable segments.

The second form is no different. Form MOC 2833, dated August 10, 2005, is titled *CCGC – Foreman Station Slickout.*[106] As with the first document, the reason for the change is the reversal and reactivation of idle pipeline. Reviewing the document and attached communications reveals no discussion or analysis of the merger of the testable segments. The documentation in the record is absent any MOC that expressly addresses the combination of testable segments.

Accordingly, I find EMPCo violated 49 C.F.R. § 195.452(b)(5) by failing to follow its written integrity management program procedures for documenting MOC for the merger of four testable segments into two.

The above findings of violation in Items 1–9 will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

The Notice proposed a civil penalty of $2,659,200 for the violations cited above in Items 1–9. Under 49 U.S.C. § 60122, a person found to have violated the pipeline safety regulations is liable for a civil penalty. Prior to 2012, administrative civil penalties could not exceed $100,000 per violation for each day of the violation, up to a maximum of $1,000,000 for any related series of violations. On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 increased the maximum penalty to $200,000 per violation for each day, up to a maximum of $2,000,000 for a related series of violations.[107]

In determining the amount of a civil penalty under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, PHMSA must consider the following criteria: the nature, circumstances and gravity of the violation, including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; the good faith of Respondent in attempting to comply with the pipeline safety regulations; and the effect on Respondent's ability to continue in business. In addition, PHMSA may consider the economic benefit gained from the violation and such other matters as justice may require.

Liability for Civil Penalties

As a threshold matter, Respondent argued there is no basis for a civil penalty in this matter because the Pipeline Safety Act (PSA) does not create strict liability for pipeline accidents.

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[105] Prehearing Submission, Exhibit 10 – EMPCo MOC Form No. 05-2829 (Aug. 10, 2005).

[106] Prehearing Submission, Exhibit 11 – EMPCo MOC Form No. 05-2833 (Aug. 10, 2005).

[107] Pub. L. No. 112-90, § 2(a), 125 Stat. 1904, 1905 (2012).

Respondent argued that it complied with all of the applicable pipeline safety regulations and that occurrence of a pipeline accident is not, by itself, a basis for a civil penalty.

PHMSA rejects this argument as Respondent committed nine violations of the safety regulations in connection with the Mayflower Accident. Under the PSA, "a person that [PHMSA] decides, after written notice and an opportunity for a hearing, has violated . . . a regulation prescribed or order issued under this chapter is liable to the United States Government for a civil penalty . . . ."[108] Since EMPCo committed violations of regulations prescribed under the PSA, the Company is liable for civil penalties in this proceeding.

Related Series of Violations

Respondent also contested the penalty on grounds that it exceeds the maximum penalty authorized by statute for a "related series of violations." Specifically, Respondent argued Items 1–4 and 7 are a related series of violations and the combined penalty should be no higher than the maximum permitted by statute for a single related series of violations. Respondent argued the combined penalties should be no more than $1,000,000 as that was the maximum for a related series of violation that occurred prior to 2012.[109] Respondent contended that Items 1–4 and 7 were a single related series because they all rely on the same assertion by the Agency that EMPCo failed to consider the Pegasus Pipeline to be susceptible to seam failure.[110]

Respondent's argument concerns language in the PSA that caps the administrative penalty for a related series of violations. In particular, the PSA states that a person who commits a violation is liable "for a civil penalty of not more than $200,000 for each violation. A separate violation occurs for each day the violation continues. The maximum civil penalty under this paragraph for *a related series of violations* is $2,000,000."[111]

PHMSA has previously addressed what constitutes "a related series of violations" under this provision.[112] PHMSA has explained that the phrase refers to a series of daily violations.[113] The

[108] 49 U.S.C. § 60122(a)(1).

[109] Since each of the violations except Item 5 occurred (or continued to occur) after the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA applies the current cap to those violations. Only Item 5, which occurred entirely before 2012 would be subject to the caps that existed prior to the new statute.

[110] Post-hearing Brief at 13 (stating that all the items were "inextricably intertwined and stem from one underlying PHMSA allegation").

[111] 49 U.S.C. § 60122(a)(1) (emphasis added).

[112] *See, e.g.*, Colorado Interstate Gas Co., CPF No. 5-2008-1005, 2009 WL 5538649 (Nov. 23, 2009); Enbridge Energy Partners, L.P., CPF No. 3-2008-5011, 2010 WL 6531629 (Aug. 17, 2010); Williams Gas Pipeline Co., CPF No. 5-2009-1003, 2010 WL 6539190 (Oct. 14, 2010); Columbia Gulf Transmission Co., CPF No. 4-2009-1005, 2011 WL 1919519 (Mar. 21, 2011); Kinder Morgan Liquids Terminals LLC, CPF No. 1-2011-5001, 2012 WL 6184429 (Oct. 17, 2012); ExxonMobil Pipeline Co., CPF No. 5-2013-5007, at 22, 2015 WL 780721, *18 (Jan. 23, 2015), *decision on reconsideration*, 2015 WL 4652714, *4 (June 12, 2015).

Agency has rejected the suggestion that all violations related to a single accident are necessarily a related series, as that "would effectively limit the number of violations that PHMSA could assess penalties on in cases where each violation had sufficient seriousness to hit the daily cap."[114] This would also be contrary to efforts by Congress over the years to increase the maximum penalties PHMSA is authorized to assess administratively for serious violations.

PHMSA recognizes the possibility, however, that separately alleged violations may be so related that they should be considered a single offense for the purpose of assessing a civil penalty.[115] In appropriate instances, PHMSA has analyzed violations to ensure that alleged violations are indeed separate, meaning they each require proof of an additional fact, or have their "own evidentiary basis."[116]

For example, in *Colorado Interstate Gas Company*, PHMSA found that two separately alleged violations were essentially the same because both alleged the operator had failed to conduct adequate oversight of its line locator and both involved the exact same evidence, namely, the conduct of the employee responsible for overseeing the line locator.[117] The two violations were found to be so related they constituted a single offense. A third violation that involved addressing encroachments was found to be separate.

In response to the argument raised by Respondent, PHMSA evaluated Items 1–4 and 7 to determine if they are so related that the Agency should considered them to be a single violation for purpose of applying the penalty caps. PHMSA finds that while the violations all relate to the finding that Respondent failed to conclude its pipeline was susceptible to seam failure, each violation concerns a separate regulatory requirement and requires proof of additional facts.

The regulation in Item 1 concerned the requirement to consider the risk of ERW pipe seam failure in developing an assessment schedule. The regulation in Item 2 concerned the requirement to perform an integrity assessment using a method capable of evaluating seam integrity within five years. Item 2 required the additional proof that Respondent failed to

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[113] Colorado Interstate Gas Co., CPF No. 5-2008-1005, at 12, 2009 WL 5538649, *9 (Nov. 23, 2009) ("The statute limits an individual violation to $100,000 per day up to $1,000,000 if that individual violation continued for a series of days, the number of which multiplied by the per-day amount would otherwise exceed $1,000,000").

[114] *Id.* Respondent's citation to the Congressional Record on September 7, 2000, is immaterial. Prehearing Submission at 23, fn. 19. The reference concerns a Senate bill that was never enacted and the information collection activities discussed therein are not at issue here.

[115] Colorado Interstate Gas, CPF No. 5-2008-1005, at 12, *citing* Blockburger v. United States, 284 U.S. 299, 304 (1932) ("where the same act or transaction constitutes a violation of two distinct statutory provisions, the test to be applied to determine whether there are two offenses or only one, is whether each provision requires proof of a fact which the other does not"). *Cf.* 49 U.S.C. § 60122(f) (prohibiting separate penalties for violating a regulation and violating an order if both violations are based on the same act).

[116] Colorado Interstate Gas, CPF No. 5-2008-1005, at 12.

[117] Colorado Interstate Gas, CPF No. 5-2008-1005, at 14.

perform a seam integrity assessment within five years. The regulation in Item 3 concerned a requirement to notify OPS when an assessment will be outside the mandatory five-year period; it required the additional proof that Respondent failed to notify OPS. The regulation in Item 4 concerned a requirement to prioritize pipeline segments for assessment based on risk factors, and required proof that Respondent improperly prioritized segments for assessment. The regulation in Item 7 concerned a requirement to perform accurate risk assessments under the operator's IMP, and required proof that Respondent failed to update a risk assessment when an had not in fact been performed as scheduled.

PHMSA finds that each violation involved a separate regulatory requirement and required proof of an additional fact. For this reason, Items 1–4 and 7 are not so related that they should be considered a single offense.

Consideration of Assessment Criteria

PHMSA next considers the civil penalty assessment factors set forth in 49 U.S.C. § 60122 and 49 C.F.R. § 190.225 for each violation in Items 1–9. Respondent's assertions concerning mitigating factors are also addressed below.

Item 1: The Notice proposed a civil penalty of $737,200 for the violation of § 195.452(e)(1). Respondent violated § 195.452(e)(1) by failing to properly consider the susceptibility of pre-1970 ERW pipe to seam failure when establishing a continual assessment schedule based on all risk factors of the Pegasus Pipeline. Respondent considered seam failure susceptibility by hydrostatic testing, ILI, and seam failure analyses, but Respondent did not give proper consideration to the historical incidence of seam failures and material toughness of the pipe in concluding the pipeline was not susceptible to seam failure.

The proposed penalty amount was based on assertions in the Notice and Violation Report relevant to the assessment criteria in § 190.225. With regard to nature, circumstances and gravity of the violation, including adverse impact on the environment, the Violation Report suggested the violation had the highest level of gravity because the violation was a causal factor in the Mayflower Accident, which was caused by ERW seam failure.

All four segments of the Northern Section of the Pegasus Pipeline had pre-1970 ERW pipe and were all determined by Respondent not to be susceptible to seam failure despite historical seam failures during testing and in-service. The Mayflower Accident caused deployment of local emergency responders, evacuation of nearby homes, threatened Lake Conway and drinking water supplies, and caused property damage over $57 million.

Having reviewed the record, PHMSA finds the highest level of gravity is appropriate and that the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability and good faith, the Violation Report suggested Respondent was culpable—or to blame—for the violation because Respondent failed to take appropriate action to comply with a requirement that was clearly applicable. The Violation Report also suggested that no good faith credit was warranted.

Respondent argued that it should be credited with good faith because the Company was prompt, diligent and thorough in responding to and investigating the incident, has spent over $75 million in response to the accident, and continues to review and revise its procedures in consideration of the investigation.

When considering good faith of a respondent under the assessment criteria, PHMSA looks at the operator's attempt to comply with the cited regulation prior to occurrence of the violation.[118] It is generally not relevant what actions the respondent took after the violation was committed. Operators already have a duty to respond promptly to accidents on their system and to investigate them to prevent recurrence.[119] Accordingly, PHMSA does not find Respondent's response to the accident and subsequent measures warrant a reduction to the penalty.

Based on a review of the evidence in the record, PHMSA finds the proposed civil penalty is appropriate under the applicable assessment criteria and are supported by the evidence. Accordingly, Respondent is assessed a civil penalty of $737,200 for the violation of § 195.452(e)(1).

Item 2: The Notice proposed a civil penalty of $737,200 for the violation of § 195.452(j)(3). Respondent failed to reassess the Northern Section of the Pegasus Pipeline within five years or 68 months. Respondent performed a baseline assessment that evaluated seam integrity in 2005–2006, but failed to perform a subsequent assessment that evaluated seam integrity until a TFI tool was run in 2012–2013, exceeding the five-year interval. Respondent ran an MFL-combo tool in the interim, but that tool was not capable of assessing seam integrity.

The proposed penalty amount was based on assertions in the Notice and Violation Report relevant to the penalty assessment criteria in § 190.225. With regard to the nature, circumstances and gravity of the violation, including adverse impact on the environment, the Violation Report suggested the highest level of gravity because the violation was a causal factor in the Mayflower Accident. The Violation Report noted that all four segments of the Northern Section of the Pegasus Pipeline had pre-1970 ERW pipe and all four were not reassessed within five years using a method capable of evaluating the integrity of the seam. Having reviewed the record, PHMSA finds the highest level of gravity is appropriate and that the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability and good faith, the Violation Report suggested Respondent was culpable for the violation because Respondent failed to take appropriate action to comply with the regulation. The Violation Report also suggested that that no good faith credit was warranted.

Based on a review of the evidence in the record, PHMSA finds the above assertions are supported by the evidence and the proposed civil penalty is appropriate under the applicable

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[118] City of Richmond, Virginia, CPF No. 1-2013-0001, 2014 WL 2875598 (May 2, 2014).

[119] *E.g.*, § 195.402(c)(5)-(6), (e).

assessment criteria. Accordingly, Respondent is assessed a civil penalty of $737,200 for the violation of § 195.452(j)(3).

Item 3: The Notice proposed a civil penalty of $56,100 for the violation of § 195.452(b)(5). Respondent failed to implement and follow provisions of its integrity management program for notifying OPS when the Company exceeded the five-year assessment interval. Respondent extended its scheduled seam assessment of the Conway to Corsicana segment first from 2011 to 2012, then again to 2013, but failed to notify OPS as required by its procedures and § 195.452(j)(4).

With regard to the nature, circumstances and gravity of the violation, including adverse impact on the environment, the Violation Report suggested that pipeline integrity had been significantly compromised as a result of the delay in reassessment and failure to notify OPS. The Violation Report noted that both segments from Conway to Corsicana were impacted and the violation continued until the tool run was performed. Having reviewed the record, PHMSA finds the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability and good faith, the Violation Report suggested that Respondent was culpable for the violation because Respondent failed to take appropriate action to comply with the regulation, and that no good faith credit was warranted.

Based on a review of the evidence in the record, PHMSA finds the above assertions are supported by the evidence and the proposed civil penalty is appropriate under the applicable assessment criteria. Accordingly, Respondent is assessed a civil penalty of $56,100 for the violation of § 195.452(b)(5).

Item 4: The Notice proposed a civil penalty of $47,500 for the violation of § 195.452(e)(1). Respondent failed to prioritize the Conway to Corsicana segment—where the Mayflower Accident occurred—for seam integrity assessment before assessment of the Patoka to Conway segment. The Conway to Corsicana segment had significantly more pre-1970 ERW pipe than the Patoka to Conway segment, and had a higher number of prior seam failures during hydrostatic testing and in-service. Respondent's decision to prioritize the Patoka to Conway segment for seam integrity assessment was not appropriately based on all of the risk factors that reflect susceptibility to seam failure.

With regard to the nature, circumstances and gravity, the Violation Report suggested pipeline integrity had been compromised as a result of not assessing the Conway to Corsicana segment first. The Violation Report noted that the seam integrity assessment occurred on the Conway to Corsicana segment approximately 916 days after the assessment on the Patoka to Conway segment. Having reviewed the record, PHMSA finds the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability and good faith, the Violation Report suggested that Respondent was culpable for the violation because Respondent failed to take appropriate action to comply with the regulation, and that no good faith credit was warranted.

Based on a review of the evidence in the record, PHMSA finds the above assertions are supported by the evidence and the proposed civil penalty is appropriate under the applicable assessment criteria. Accordingly, Respondent is assessed a civil penalty of $47,500 for the violation of § 195.452(e)(1).

Item 5: The Notice proposed a civil penalty of $56,100 for the violation of § 195.452(h)(1). Respondent discovered at least two immediate repair conditions on the Conway to Corsicana segment in 2010 and 2011, but failed to take prompt action by temporarily reducing operating pressure until immediate repairs were completed.

With regard to the nature, circumstances and gravity, the Violation Report suggested that pipeline safety had been significantly compromised as a result of failing to safely reduce pressure pending the remediation of immediate repair conditions. With regard to the degree of culpability and good faith, the Violation Report suggested that Respondent was culpable for the violation because Respondent failed to take appropriate action to comply with the regulation, and that no good faith credit was warranted.

Based on a review of the evidence in the record, PHMSA finds the above assertions are supported by the evidence and the proposed civil penalty is appropriate under the applicable assessment criteria. Accordingly, Respondent is assessed a civil penalty of $56,100 for the violation of § 195.452(h)(1).

Item 6: The Notice proposed a civil penalty of $102,200 for the violation of § 195.452(h)(2). Respondent failed to promptly discover conditions on the Pegasus Pipeline within 180 days after an integrity assessment. Respondent performed four integrity assessments on the Northern Section from Patoka to Corsicana during 2010–2013, but failed to promptly discover conditions until weeks or months after the 180-day deadline had expired in each instance. The delay was influenced, in part, by an earlier decision of EMPCo to combine four testable segments into two, resulting in two sizable testable segments of over 300 miles each that required additional time for processing of the ILI data and discovery of conditions.

With regard to the nature, circumstances and gravity, the Violation Report suggested that pipeline safety had been significantly compromised as a result of the delay in discovering conditions and making repairs on the pipeline. The Violation Report also noted this was a repeat violation.[120] Having reviewed the record, PHMSA finds the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability and good faith, the Violation Report suggested that Respondent was culpable for the violation because Respondent failed to take appropriate action to comply with the regulation, and that no good faith credit was warranted.

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[120] ExxonMobil Pipeline Co., CPF No. 4-2011-5016, Item 2(a), 2013 WL 4478404, at *12 (Jun. 27, 2013) (finding EMPCo violated § 195.452(h)(2) by failing to discover conditions on its Melville to Boyce crude oil pipeline as soon as practicable following receipt of the ILI data from the tool vendor).

Based on a review of the evidence in the record, PHMSA finds the above assertions are supported by the evidence and the proposed civil penalty is appropriate under the applicable assessment criteria. Accordingly, Respondent is assessed a civil penalty of $102,200 for the violation of § 195.452(h)(2).

Item 7: The Notice proposed a civil penalty of $70,500 for the violation of § 195.452(b)(5). Respondent failed to follow the provisions of its IMP related to periodic evaluation. Respondent extended the timing of a TFI tool run without evaluating and updating risk assessments that had relied upon the tool run having already been performed.

With regard to the nature, circumstances and gravity, the Violation Report suggested that pipeline safety had been significantly compromised as a result of the failure to update the risk assessments. Having reviewed the record, PHMSA finds the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability, the Violation Report suggested that Respondent had a higher degree of culpability for the violation because Respondent's MOC documentation cited fiscal goals as the reason for delaying the TFI tool run. Respondent contested the elevated culpability as the Company never made a conscious decision to disregard the law.

PHMSA agrees with Respondent that the MOC documentation does not prove elevated culpability with regard to Respondent's failure to update its risk assessment. This results in a lower penalty. The record does not support any further reduction for good faith.

Accordingly, Respondent is assessed a reduced civil penalty of $56,100 for the violation of § 195.452(b)(5).

Item 8: The Notice proposed a civil penalty of $783,300 for a violation of § 195.402(a), but the conduct alleged was found more precisely to be a violation of § 195.452(b)(5). Respondent failed to follow its IMP procedures for using the TIARA program when assessing risk on the Conway to Foreman segment of the Pegasus Pipeline. One of the questions in the program was whether or not a TFI tool run had been performed. Respondent answered Yes, which produced certain results in the risk assessment, even though the TFI tool was not run until years later.

With regard to the nature, circumstances and gravity of the violation, including adverse impact on the environment, the Violation Report suggested the violation had the highest level of gravity because the violation was a causal factor in the Mayflower Accident, which was the result of ERW pipe seam failure. In addition, with regard to the degree of culpability and good faith, the Violation Report suggested that Respondent had an elevated degree of culpability and that no good faith credit was warranted.

To support these assertions, the Violation Report noted, and OPS repeated at the hearing, that Respondent intentionally answered Yes, knowing that doing so would reduce the risk of the pipeline under assessment.[121] Internal company emails documented that when answering the

[121] *E.g.*, Hearing Transcript at 57–58.

question No "there are identified and integrity threats though Manufacturing," but by answering Yes, "all the threats in Manufacturing went away."[122] A reply email stated that since the seam assessment run was planned for the summer, the employee should "go head and upload the risk assessment with the D3 score and no Manufacturing Threats so it's representative of the pipeline going forward."[123] Other communications stated that if a No answer resulted in a risk assessment that was too high, "we may just leave the answer as YES and use the 'with crack tool score' going forward anyway since it will represent the future situation."[124]

Respondent contested the elevated culpability and argued that the Company answered Yes because it intended to represent that the tool would be run sometime in the next five years. Respondent also contended that regardless of there being no identified threats, the Company implemented preventative and mitigative measures and decided to run a TFI seam/crack tool.

PHMSA finds the question in the TIARA program asked solely if a crack tool had been run in the past and if repairs had been scheduled. The question did not contain any qualifications about planning a run in the future. Although Respondent may have planned to implement preventative and mitigative measures such as emergency flow restricting devices, the Company acknowledged at the hearing that installation of those measures had not taken place.[125]

Having reviewed the record, PHMSA finds the evidence supports an elevated culpability for Respondent's failure to accurately answer the TIARA crack tool question. Also, the highest level of gravity is appropriate for the violation. The above assertions are appropriately based on the record, and the proposed civil penalty amount is supported by the applicable assessment criteria. Accordingly, Respondent is assessed a civil penalty of $783,300 for the violation of § 195.452(b)(5).

Item 9: The Notice proposed a civil penalty of $69,100 for the violation of § 195.452(b)(5). Respondent failed to follow its IMP procedures for documenting the management of change (MOC) when it merged testable segments on the Pegasus Pipeline. Respondent previously had identified four testable segments on the Northern Section of the Pegasus Pipeline from Patoka to Corsicana. Respondent combined the four segments into two testable segments, but failed to document the MOC as required by its IMP.

With regard to the nature, circumstances and gravity, the Violation Report suggested that pipeline safety had been significantly compromised as a result of the failure to document management of change.

By failing to document MOC, Respondent did not properly evaluate what the impacts would be to the IMP by combining testable segments. The impacts were significant as they contributed to a delay in receiving the results of the integrity assessments beyond the regulatory deadline for

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[122] Violation Report, Exhibit J – email dated Mar. 7 2011.

[123] Violation Report, Exhibit J – email dated Mar. 14, 2011.

[124] Violation Report, Exhibit J – email dated Feb. 28, 2011.

[125] Hearing Transcript at 61.

discovering conditions.[126] Having reviewed the record, PHMSA finds the nature, circumstances and gravity of the violation support the penalty amount.

With regard to the degree of culpability and good faith, the Violation Report suggested that Respondent had a higher degree of culpability for the violation because the segments were combined for cost savings reasons. Respondent contested the elevated culpability and argued that it never made a conscious decision to disregard the law.

PHMSA agrees with Respondent that the reasons for combining testable segments does not prove elevated culpability with regard to its failure to follow procedures for documenting MOC. This results in a lower penalty. The record does not support any further reduction for good faith.

Accordingly, Respondent is assessed a reduced civil penalty of $54,700 for the violation of § 195.452(b)(5).

Due Process and Policy Considerations

Finally, Respondent argued the proposed penalty "should be reduced for due process and policy reasons," because the Agency has not adopted a penalty policy or guidance describing how it exercises its penalty authority.[127] In addition, Respondent argued the Agency failed to explain in the Notice how the penalty was derived or whether multi-day assessments were included. Respondent argued this violated due process as well as the Administrative Procedure Act, which requires that "the matters of fact and law [be] asserted."[128]

PHMSA has previously considered a similar argument raised by EMPCo.[129] As stated in the earlier case, the civil penalty assessment factors are listed in both 49 U.S.C. § 60122 and 49 C.F.R. § 190.225. Operators are free to submit information relevant to those factors to support reducing or withdrawing a penalty. In addition, under § 190.208(c), respondents may request a copy of the case file, which includes the Violation Report with the evidentiary support for the allegations in the Notice and discussion of the penalty assessment factors and relevant factual assertions that influenced the proposed penalty for each violation.[130] The duration of any multi-day violations is also specified.[131] PHMSA also provides, upon request, a general outline of how

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[126] OPS also alleged that combining the testable segments diluted risk scores, but Respondent argued that this was not possible.

[127] Prehearing Submission at 26.

[128] Prehearing Submission at 26, *citing* 5 U.S.C. § 554(b)(3).

[129] ExxonMobil Pipeline Co., CPF No. 5-2013-5007, at 27, 2015 WL 780721, *23 (Jan. 23, 2015).

[130] *See, e.g.*, Violation Report at 9-12 (describing assessment criteria for the penalty in Item 1).

[131] *See, e.g.*, Violation Report at 10 (alleging the duration of Item 1 was at least 2,370 days from the date of the 2006 hydrostatic test to the date of the Mayflower Accident).

civil penalties are calculated.[132] All of this material may be received and reviewed by a respondent before or after responding to a notice of probable violation.

In this case, EMPCo has received all of this information and was able to respond to it. PHMSA finds there was sufficient information to afford Respondent an opportunity to present a defense to the proposed penalty. Accordingly, PHMSA rejects Respondent's argument that the penalty should be reduced for due process and policy reasons.

Other Considerations

Under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, PHMSA must also consider the history of Respondent's prior offenses and the effect of the penalty on Respondent's ability to continue in business. The Violation Report noted a total of 12 prior offenses in the five-year period prior to issuance of the Notice. Respondent did not claim the penalties would affect its ability to continue in business.

Penalty Assessment

In summary, having reviewed the record and considered the assessment criteria for each of the Items cited above, Respondent is assessed a total civil penalty of **$2,630,400**.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require such payment to be made by wire transfer through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMK-325), Federal Aviation Administration, Mike Monroney Aeronautical Center, 6500 S Macarthur Blvd, Oklahoma City, OK 73169. The Financial Operations Division telephone number is (405) 954-8845.

Failure to pay the $2,630,400 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Failure to pay the civil penalty may result in referral of the matter to the Attorney General for action in a district court of the United States.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to the violations cited above in Items 1, 2, 5, 6, and 8. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids by pipeline or who owns or operates a pipeline facility is required to comply

[132] *See* Administrative Procedures; Updates and Technical Corrections, 78 Fed. Reg. 58897, 58901 (Sept. 25, 2013) (explaining that a general outline of how civil penalties are calculated is provided upon request).

with the applicable safety standards established in 49 C.F.R. Part 195. PHMSA may issue an order directing compliance pursuant to 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217.

In its written submissions and at the hearing, Respondent argued the proposed compliance order (PCO) should be withdrawn because some of the corrective actions are too broad. Specifically, Respondent noted the provisions in Paragraph 1 of the PCO apply to all pre-1970 ERW pipe covered by Respondent's IMP. Respondent contended there is no authority for PHSMA to apply a compliance order in this case to company assets that were not involve in the Mayflower Accident at issue.

The proposed corrective action in Paragraph 1 of the PCO concerns Respondent's IMP procedures for addressing seam failure susceptibility. The actions relate to the finding that Respondent had failed to properly consider pre-1970 ERW pipe susceptible to seam failure on the Pegasus Pipeline. Among other things, Paragraph 1 of the PCO would require Respondent to modify its IMP to ensure risks are adequately identified and assessment actions are carried out to address the specific nature of all pre-1970 ERW pipe covered by the IMP.

The corrective action contained in Paragraph 1 is appropriately within the authority of PHMSA to "issue orders directing compliance" with the integrity management regulations.[133] The finding of violation in Item 1 raises critical issues about the manner in which Respondent's IMP evaluates the risk of seam failure on all pre-1970 ERW pipe. These issues include failure to adequately consider historical seam failures and pipe toughness. These issues must be addressed to ensure future compliance. The corrective actions in Paragraph 1 are tailored to addressing those issues in a way that will enable PHMSA to confirm Respondent's IMP properly considers the risk of seam failure on pre-1970 ERW pipe covered by the IMP. In addition, since Respondent's IMP applies to all covered pipelines that could affect an HCA, ordering the modification of the IMP unavoidably impacts more pipelines than solely the Pegasus Pipeline.

Respondent cited a court decision that "injunctive relief [must] be narrowly tailored to the specific harm alleged (not potential harm)."[134] I find the decision inapplicable, as it concerned the standards for determining the appropriate scope of a preliminary injunction in U.S. District Court not an administrative compliance order after an adjudication. Accordingly, I find the proposed actions are appropriate and not prohibitively broad.

Respondent also argued the proposed compliance order should be withdrawn because the Company "has already begun work on virtually all actions addressed" in the proposed order and eventually expects to address all of the elements.[135] In addition, Respondent contended the timeframes set forth in the PCO are unreasonable and unworkable.

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[133] 49 U.S.C. § 60118(b).

[134] Post-hearing Brief at 15, *citing* Ahearn ex rel. N.L.R.B. v. Remington Lodging & Hospitality, 842 F. Supp. 2d 1186, 1205-06 (D. Alaska 2012).

[135] Post-hearing Brief at 15.

PHMSA recognizes that Respondent may already be taking actions specified in the proposed compliance order, which is encouraged. PHMSA has determined these actions are necessary to achieve compliance. The actions must be completed according to the terms of the order, and documentation must be submitted to PHMSA demonstrating completion. Since Respondent has not yet achieved compliance with the terms of the order, the order will remain in effect until compliance is achieved by EMPCo. With regard to Respondent's contention concerning timeframes, the PCO authorizes the Director to modify the deadlines set forth in the PCO if Respondent demonstrates good cause for an extension of time to comply.

Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, EMPCo is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to the violation of § 195.452(e)(1) (**Item 1**), EMPCo must modify its Integrity Management Program (IMP) procedures for seam failure susceptibility analyses, seam integrity assessment plans, and threat modeling to ensure risks are adequately identified and assessment actions are carried out to address the specific nature of all pre-1970 ERW pipe covered by the IMP. In carrying out this Item, EMPCo must complete at a minimum, the following actions:

   (a) Within 30 days of issuance of the Final Order, EMPCo must prepare and submit to PHMSA a spreadsheet identifying all pre-1970 ERW pipe covered by the IMP that are subject to 49 C.F.R. Part 195.

   (b) Within 30 days of issuance of the Final Order, EMPCo must identify, catalogue, and submit to the Director a list of all IMP processes used by EMPCo in the risk assessment and integrity decisions related to the determination of seam failure susceptibility, development of Seam Integrity Assessment Plans (SIAP), and assessment of pre-1970 ERW pipe.

   (c) Within 90 days of issuance of the Final Order, EMPCo must review the risk scoring of pre-1970 ERW pipe in its TIARA processes and incorporate enhancements to ensure that the risk levels attributed to segments deemed susceptible to seam failure receive appropriate heightened risk scores to ensure Identified Threats are not overlooked, and that the appropriate considerations are incorporated into the questionnaire used in the TIARA process for manufacturing threats. The risk analysis of pre-1970 ERW pipe must not be a relative ranking against other assets and must be conducted in a manner that ensures appropriate management review and approval of all integrity decisions for risk reduction actions related to pre-1970 ERW pipe.

   (d) Within 120 days of issuance of the Final Order, EMPCo must revise its Seam Failure Susceptibility Analysis (SFSA) Process to incorporate up-to-date knowledge and relevant results of the operator and industry knowledge from failure analyses and research. The revised SFSA process must be reviewed by a third party expert, with prior approval of the Director, to ensure adequate consideration of all relevant aspects of the management of pre-1970 ERW pipe are incorporated into the SFSAs and resultant SIAPs.

(e) Within 120 days of issuance of the Final Order, EMPCo must revise its process for conducting crack growth analyses through pressure-cycle-fatigue modeling to ensure that appropriately conservative assumptions are used to develop re-inspection intervals and incorporate these practices into its Fatigue Analysis (FA) procedures. The revised FA process must be reviewed by a third party expert, with prior approval of the Director, to ensure adequate consideration of all relevant aspects of the management of pre-1970 ERW pipe are incorporated into the FAs and the resultant reassessment intervals for pipe subject to pressure-cycle-fatigue.

2. With respect to the violation of § 195.452(j)(3) (**Item 2**), EMPCo must ensure that its procedures for assessment intervals clearly identify that all risk factors must be assessed within the regulatory timeframes, or less, based upon the appropriate engineering analyses, but in no case shall they exceed 5 years or 68 months as required by §195.452(i)(3). EMPCo must submit documentation to the Director demonstrating the requirements of this paragraph have been satisfied within 60 days of issuance of this Order.

3. With respect to the violations of §§ 195.452(h)(1) and (h)(2) (**Items 5 and 6**), EMPCo must revise its IMP processes to ensure timely discovery and interim discovery for preliminary reports such that immediate repair conditions are clearly identified regardless of the type of report provided by the vendor (e.g., telephone call, spreadsheet, preliminary, final, binder, etc.) and that discovery of the condition occurs. Revisions to the Company's processes must address appropriateness of the manageable size of testable segments to ensure timely response to integrity assessments and remedial actions. EMPCo must submit documentation to the Director demonstrating the requirements of this paragraph have been satisfied within 60 days of issuance of this Order.

4. With respect to the violations of §§ 195.452(h)(1) and (h)(2) (**Items 5 and 6**), EMPCo must revise its IMP processes to ensure timely discovery occurs no later than 180 days after completion of an integrity assessment. EMPCo must review its IMP processes utilizing personnel (company or consultants) from outside of its IM group in accordance with its OIMs process of external audits to ensure an objective review of processes, past performance, and recommended enhancements to facilitate timely discovery is achieved in compliance with the federal pipeline safety regulations. The review must specifically examine the process outlined in the Company's IMP process flow chart depicted by User's Guide Figure 4.2: Integrity Assessment & Repair Flow Chart. The review must specifically address the types of defects for which TFI, UT, EMAT tools or hydrostatic testing shall be utilized. The audit must result in a report of findings and recommended enhancements submitted to PHMSA, and incorporated into the revision of the Company's IMP processes. EMPCo must submit a scope of work and proposed schedule to satisfy the requirements of this paragraph to the Director for review and approval within 90 days of issuance of this Order.

5. With respect to the violations of §§ 195.452(h)(1) and (h)(2) (**Items 5 and 6**), EMPCo must conduct an internal investigation of the ability of its OIMS, IMP and interrelated management processes to adequately identify and assess the risk of, and take appropriate risk reduction activities to address the threat of, potential seam failures on the Pegasus Pipeline. The investigation must be conducted by EMPCo personnel, with risk assessment, HAZOP, and Safety Management System experience from outside of the organization who are qualified to perform such assessments in accordance with OIMS 2A requirements. Alternatively, a qualified consultant or contractor may be used in lieu of EMPCo personnel with prior approval of the Director. A summary of the findings and resultant recommendations must be submitted to the Director, and incorporated into the revisions carried out in response to this Compliance Order. The investigation may be integrated with the audit required in Paragraph 4 of this Compliance Order. EMPCo must submit to the Director, for review and approval, a scope of work and proposed schedule to satisfy the requirements of this paragraph within 90 days of issuance of this Order.

6. With respect to the violation of § 195.452(b)(5) (**Item 8**), EMPCo must revise its Risk Assessment processes to ensure appropriate training, interdisciplinary participation, and management level review and oversight are carried out to ensure that the integrity decisions that affect the final risk scores are not manipulated, or that processes are not circumvented, and that risk assessment assumptions are appropriately conservative. The revised process must ensure that checks and balances are integrated into the process to avoid conflicting budget goals with integrity prioritization decisions. The revised process must include revisions to change management processes to ensure that a feedback loop to any previous risk decision requires risk assessments be updated as changes occur. The results of Paragraphs 4 and 5 of this Compliance Order must be incorporated into the process improvements carried out under this paragraph. EMPCo must submit documentation to the Director demonstrating the requirements of this paragraph have been satisfied within 150 days of the issuance of this Order.

7. With respect to the violation of § 195.452(b)(5) (**Item 8**), EMPCo must revise its Risk Assessment and Data Integration processes to ensure that Identified Threats are not discounted, and that greater reliance is placed upon knowledge of the asset, its previous assessments, and its operating history over the TIARA results in the IM processes. The results of Paragraphs 4 and 5 of this Compliance Order must be incorporated into the process improvements carried out under this paragraph. EMPCo must submit documentation to the Director demonstrating the requirements of this paragraph have been satisfied within 150 days of the issuance of this Order.

8. It is requested that EMPCo maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to the Director. It is requested that these costs be reported in two categories: (1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and (2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

Failure to comply with this Compliance Order may result in the administrative assessment of civil penalties not to exceed $200,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

Under 49 C.F.R. § 190.243, Respondent may submit a petition for reconsideration of this Final Order to the Associate Administrator for Pipeline Safety, PHMSA, 1200 New Jersey Avenue SE, East Building, 2nd Floor, Washington, D.C. 20590, no later than 20 days after receipt of the Final Order by Respondent. A petition must contain a statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.243. The filing of a petition automatically stays the payment of any civil penalty assessed, however, the other terms of the order, including the corrective action, remain in effect unless the Associate Administrator, upon request, grants a stay.

The terms and conditions of this Final Order are effective upon service in accordance with 49 C.F.R. § 190.5.

Linda Daugherty

For Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

OCT 0 1 2015

Date Issued

Tab 2

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Ave, S.E.
Washington, D.C. 20590

APR 0 1 2016

Mr. Gerald S. Frey
Global Pipeline Manager & President
ExxonMobil Pipeline Company
22777 Springwoods Village Pkwy
E3.5A.521
Spring, TX 77389-1425

Re: CPF No. 4-2013-5027

Dear Mr. Frey:

Enclosed is the Decision on the Petition for Reconsideration issued in the above-referenced case. For the reasons explained in the decision, the petition filed by ExxonMobil Pipeline Company is denied. When the civil penalty assessed in the Final Order has been paid and the terms of the compliance order completed, as determined by the Director, Southwest Region, the enforcement action will be closed. This decision constitutes the final administrative action in this proceeding. Service is made pursuant to 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Rod Seeley, Director, Southwest Region, PHMSA
Mr. Bob Hogfoss and Ms. Catherine Little, Hunton & Williams LLP, Bank of America Plaza, Suite 4100, 600 Peachtree Street, N.E., Atlanta, GA 30308

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
ExxonMobil Pipeline Company,	)	**CPF No. 4-2013-5027**
Petitioner.	)	

DECISION ON PETITION FOR RECONSIDERATION

On March 29, 2013, the Pegasus Pipeline operated by ExxonMobil Pipeline Company (EMPCo, the Company, or Petitioner) experienced a failure near the town of Mayflower, Arkansas. The failure resulted in the release of approximately 5,000 barrels of crude oil in a residential area. Twenty-two households were evacuated. The accident caused property damage of more than $57 million.[1]

Following an investigation by the Pipeline and Hazardous Materials Safety Administration (PHMSA or Agency), Office of Pipeline Safety (OPS), the Director of the Southwest Region issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) on November 6, 2013. The Notice alleged that EMPCo committed nine violations of the pipeline safety regulations in connection with the accident, proposed a civil penalty of $2,659,200, and proposed corrective action.

EMPCo requested a hearing on the Notice, which was held June 2, 2014, in Houston, Texas. On October 1, 2015, PHMSA issued a Final Order in accordance with 49 C.F.R. § 190.213. The Final Order made findings that EMPCo committed each of the nine violations alleged in the Notice, assessed a modified civil penalty of $2,630,400, and required corrective action set forth in a Compliance Order.

On October 21, 2015, EMPCo filed a Petition for Reconsideration requesting withdrawal of all nine violations, elimination or reduction of the civil penalty, and withdrawal of the Compliance Order. The filing of the Petition automatically stayed payment of the civil penalty in accordance with 49 C.F.R. § 190.243(c). EMPCo separately requested a stay of the Compliance Order as

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[1] For additional information regarding the pipeline accident, *see* pp. 2-4 of the Final Order issued to ExxonMobil Pipeline Co., CPF No. 4-2013-5027, 2015 WL 7175715, at *2 (Oct. 1, 2015). Enforcement decisions can be viewed on PHMSA's website at http://www.phmsa.dot.gov/pipeline/enforcement (follow links for enforcement since 2002 and then enforcement actions issued by year).

permitted under the same regulation. A stay was granted by PHMSA on November 4, 2015, and extended on February 4, 2016.

Section 190.243 allows a respondent to petition the Associate Administrator for reconsideration of a final order that has been issued pursuant to § 190.213. Reconsideration is not an appeal or a completely new review of the record. A respondent may ask for correction of an error or, in limited circumstances, may present previously unavailable information.[2] If a respondent requests consideration of additional facts or arguments, the respondent must submit the reasons they were not presented prior to issuance of the final order. Repetitious information or arguments will not be considered.[3] The Associate Administrator may grant or deny, in whole or in part, a petition for reconsideration without further proceedings.

I. Petition to Withdraw Violations in Items 1–9

Item 1 in the Final Order found that EMPCo had violated § 195.452(e)(1) by failing to establish a continual integrity assessment schedule for the Pegasus Pipeline that was based on all the risk factors that reflected the risk conditions of the pipeline.

The pipeline safety regulations at § 195.452(e)(1) require operators of pipelines that could affect a high consequence area (HCA) to develop a schedule for performing integrity assessments. The schedule must be based on risk factors that reflect the risk conditions of the pipeline. Some of the risk factors that must be considered under § 195.452(e)(1) when establishing a continual assessment schedule include the pipe material, manufacturing, seam type, results of previous integrity assessments, and leak history. Pipelines considered to be "susceptible to longitudinal seam failure" must have a continual schedule for integrity assessment that is "capable of assessing seam integrity."[4]

As determined in the Final Order, these risk factors indicated EMPCo should have considered the Pegasus Pipeline to be susceptible to seam failure and should have developed a schedule for integrity assessments to verify integrity of the seam. The pipeline was constructed in the 1940s with low-frequency electric-resistance welded (ERW) pipe manufactured by Youngstown Sheet and Tube Company. This type of pipe is known to exhibit an increased risk of longitudinal seam failure due to selective seam corrosion and manufacturing defects such as hook cracks and inadequate bonding.[5] The pipeline safety regulations expressly deem all pre-1970 ERW pipe to be presumptively susceptible to seam failure unless an engineering analysis shows otherwise.[6]

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[2] PostRock KPC Pipeline, LLC, CPF No. 3-2011-1014, at 1, 2013 WL 8284478, at *1 (Dec. 5, 2013).

[3] Plains All American Pipeline, LP, CPF No. 5-2009-0018, at 4, 2013 WL 5883403, at *3 (Aug. 30, 2013).

[4] § 195.452(j)(5).

[5] Final Order at 8. In 1988 and 1989, PHMSA issued notices to warn operators of factors contributing to failures of ERW pipelines. Alert Notice ALN-88-01 (Jan. 28, 1988) and Alert Notice ALN-89-01 (Mar. 8, 1989) *available at:* http://www.phmsa.dot.gov/pipeline/regs/advisory-bulletin.

[6] § 195.303(d).

The Pegasus Pipeline had experienced numerous seam failures during previous integrity assessments. During a hydrostatic test in 2005–2006, approximately 11 failures occurred on the ERW pipe seam. The failures were due to manufacturing defects, including lack of fusion, hook cracks, and low mechanical strength. These types of defects are known to be associated with a higher risk of seam failure on ERW pipe. Other seam failures occurred during earlier hydrostatic tests in 1991 and 1969. In addition to test failures, a small leak occurred on the seam in 1984 while the pipeline was in service.

PHMSA found the results of previous integrity assessments and leak history, together with information about the pipe material, manufacturing, and seam type demonstrated the pipeline was susceptible to seam failure and therefore EMPCo was required to establish a continual assessment schedule that accounted for the risk. The Final Order concluded EMPCo violated § 195.452(e)(1) when it failed to establish an integrity assessment schedule for periodically testing the integrity of the ERW seam. On March 29, 2013, the Pegasus Pipeline failed along the longitudinal ERW seam during operation, which resulted in the Mayflower accident.

The Final Order rejected the reasons EMPCo gave for deciding the pipeline was not susceptible to seam failure. EMPCo had stated that it discounted test failures from 2005–2006 because an analysis showed the failures did not exhibit evidence of pressure cycling induced fatigue or preferential seam corrosion. PHMSA found this conclusion was flawed because the pipe material had low toughness, EMPCo knew this, and the Company should have recognized brittle pipe would not exhibit the same evidence of fatigue cracking because it is less resistant to fracture. Likewise, PHMSA found EMPCo had inappropriately used a computer program for predicting the remaining fatigue life of the pipe to support its susceptibility determination.

In its Petition, EMPCo argued the finding of violation in Item 1 should be reversed because PHMSA improperly considered, ignored, and selectively mischaracterized certain information in the record that supported EMPCo's position. The specific assertions made by Petitioner are addressed below.

a. Assertion That PHMSA Misrepresented Industry ERW Reports

EMPCo argued the Final Order misrepresented two key industry reports that provided guidance for analyzing seam failure susceptibility on ERW pipelines. The reports are *Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation* by Michael Baker Jr., Inc. (April 2004) (Baker Report)[7] and *Dealing with Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe with Respect to HCA-Related Integrity Assessments* by John F. Kiefner (Feb. 2002) (Kiefner Report).[8] Petitioner argued the Final Order selectively ignored a requirement in the reports that operators determine if prior seam failures exhibit evidence of fatigue or preferential seam corrosion. This is significant, Petitioner argued, because prior seam failures on the Pegasus

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[7] EMPCo Prehearing Submission, Exhibit 3; OPS Failure Investigation Report (Accident Report), Appendix E, Tab H (Oct. 23, 2013). *Also available at:* https://primis.phmsa.dot.gov/iim/techreports.htm.

[8] OPS Violation Report, Exhibit D. *Also available at:* https://primis.phmsa.dot.gov/comm/FactSheets/FSHydrostaticTesting.htm.

Pipeline did not exhibit evidence of either condition, and, therefore, EMPCo was in line with the reports when it concluded the pipeline was not susceptible to seam failure.

At the outset, PHMSA emphasizes the cited reports are not incorporated by reference into § 195.452(e)(1). The regulation does not tell operators to disregard previous seam failures if there is no evidence of fatigue or selective seam corrosion. The regulation states that operators "must consider" the results of previous integrity assessments. The Pegasus Pipeline had a significant number of seam failures on its pipeline during the previous assessment. These prior failures along with information about the type of pipe at issue required EMPCo to establish a continual integrity assessment schedule that accounted for the risk of seam failure.

As the Final Order noted, Petitioner's assertions were also not as clearly supported by the industry reports as the Company suggested. For example, Petitioner asserted that operators must determine if previous seam failures have evidence of fatigue or selective seam corrosion, but the Baker Report states that an absence of fatigue does not necessarily preclude the need for periodic reassessment, and that it should be calculated "using the best available information."[9] PHMSA recognizes the same passage also states that if no fatigue-related failures occurred during a hydrostatic test, it is reasonable to assume the pipe is not susceptible to seam failure.[10] The report also states that if time-dependent growth (e.g., fatigue) is shown in the failure, reassessment becomes necessary, but the preceding sentence in that passage states that if a seam-related failure occurs, the pipeline "is considered susceptible" to seam failure.[11] The Pegasus Pipeline had multiple seam-related failures and an absence of fatigue does not necessarily preclude the need for periodic reassessment.

Likewise, the Kiefner Report states that to be excluded from a seam-integrity-assessment plan, the pipeline must "have no recorded seam-related service failure," unless the failure was the result of accidental overpressure beyond 125% maximum operation pressure (MOP).[12] The Pegasus Pipeline had seam-related failures at pressures that did not exceed 125% MOP. Elsewhere the report states that a seam-integrity-assessment plan should be developed if fatigue failures have occurred.[13]

The Final Order did not misrepresent these reports, but rather noted EMPCo had a different reading of them.[14] PHMSA rejects any contention that the cited reports override the applicable regulation by permitting operators to disregard significant seam failure history and other factors required to be considered under § 195.452(e)(1), based solely on an absence of fatigue. The hydrostatic test that took place on the Pegasus Pipeline in 2005–2006 resulted in 11 seam-related

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[9] Baker Report at 26.

[10] Baker Report at 26.

[11] Baker Report at 20. EMPCo also referenced a flowchart at p.18 of the Baker Report. OPS argued that flowchart had been expanded, citing p. 91 of the Baker Report.

[12] Kiefner Report at 7.

[13] Kiefner Report at 8.

[14] Final Order at 9, n. 41.

failures and the pipeline experienced other seam failures before that. Under PHMSA's reading of the regulation (and the cited industry reports), these seam failures along with the other factors in § 195.452(e)(1) indicated the pipeline was susceptible to seam failure.

Even were PHMSA to accept on reconsideration that more than one reading of the reports is possible, and that the presence or absence of fatigue and selective seam corrosion is relevant to a susceptibility determination, the record demonstrates EMPCo's conclusion was not reasonable. As explained in the Final Order, the failures during the 2005–2006 hydrostatic test exhibited brittle cracking. Brittle pipe, or pipe with low toughness, is less resistant to fracture when stressed and will not exhibit the same evidence of fatigue cracking as ductile pipe. EMPCo acknowledged its pipeline had low toughness, and although the Company originally attributed the low toughness to colder hydrostatic test temperatures, the temperatures were actually within the range of normal operations.[15] It was not appropriate for EMPCo to rely on the absence of fatigue without considering the reason why fatigue was not exhibited.

The Pegasus Pipeline experienced a significant number of seam failures during hydrostatic testing due to defects from manufacturing. Such defects were specifically known to be a risk associated with the type of pre-1970 ERW pipe used on the Pegasus Pipeline. The hydrostatic test failures had increased in number over the years and were occurring at lower test pressures, both indicating a likelihood that seam degradation was taking place. All of this information demonstrated the Pegasus Pipeline had a susceptibility to future longitudinal seam failure, which pre-1970 ERW pipe is already presumed to have. To conclude otherwise, regardless of exhibited evidence of fatigue, ignored the risks of the pipeline under factors that must be considered pursuant to § 195.452(e)(1). Accordingly, Petitioner's argument regarding the ERW reports is rejected.

b. Assertion That PHMSA Improperly Considered Expert Testimony

Secondly, Petitioner argued it was improper for the Final Order to dismiss the testimony of EMPCo's expert witness, notably because OPS had not offered an expert witness of its own. The testimony at issue was prepared by Dr. John Kiefner in an affidavit submitted by EMPCo prior to the hearing. Dr. Kiefner testified in support of the Company that hydrostatic failures alone are not indicative of seam failure susceptibility without evidence of fatigue or selective seam weld corrosion. He also testified that the 2013 accident exhibited unusual characteristics, and EMPCo's determination that the segment was not susceptible to seam failure was reasonable and consistent with industry guidance.

Dr. Kiefner's testimony was considered in the Final Order, although the testimony was found not to be conclusive in light of other information in the record.[16] For example, the Final Order found Dr. Kiefner's primary assertion—that seam failures without evidence of fatigue do not indicate susceptibility to seam failure—was not entirely consistent with the cited industry reports. In addition, the Final Order found it was not reasonable for EMPCo to conclude its pipeline was not

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[15] Final Order at 10.

[16] Final Order at 7, 10, 11.

susceptible to seam failure based on the absence of fatigue when appropriate consideration was not given to the reason why fatigue was not present.

The Final Order also considered Dr. Kiefner's assertion that brittle cracking at the accident site was atypical. It found, however, that it is not unusual for pre-1970 ERW pipe to exhibit brittle failures. The Final Order further found that the seam failures in 2005–2006 were caused by manufacturing defects, which are a known risk of pre-1970 ERW pipe. For these reasons, Dr. Kiefner's opinion about the reasonableness of the Company's actions was not ultimately persuasive.

Petitioner argued that OPS never offered its own expert witness, but OPS staff members who participated at the hearing possessed significant technical expertise in pipeline safety, integrity management, and ERW pipe. Unlike Dr. Kiefner, the staff members attended the hearing in person, which allowed them to answer questions and to more fully explain their statements. Dr. Kiefner was not present at the hearing and, therefore, could not answer questions, including specific questions that were raised about his apparent inconsistency with the Baker Report,[17] and questions about the data he reviewed in preparing his affidavit.[18] Petitioner enclosed a new affidavit by Dr. Kiefner with its Petition to reaffirm and supplement the witness's earlier statements.

Under § 190.243(b), there must be a justifiable reason for submitting new information after issuance of the Final Order. On occasion, PHMSA has found good cause to consider new information, such as where it concerned PHMSA's statutory authority,[19] a new company name of a respondent,[20] or where additional records were discovered.[21] PHMSA is aware of no instance in which newly created testimony was considered on reconsideration when that evidence could have been introduced prior to issuance of the Final Order.

Given that the Pegasus Pipeline was constructed with pipe known to be presumptively susceptible to seam failure and, in fact, had suffered previous seam failures during testing and while in service, PHMSA continues to find unpersuasive Dr. Kiefner's opinion regarding the reasonableness of EMPCo's actions. Accordingly, Petitioner's argument regarding the expert testimony is rejected.

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[17] Hearing Transcript at 97-101.

[18] Hearing Transcript at 113-114. EMPCo indicated that Dr. Kiefner is semi-retired.

[19] Plains All American Pipeline, LP, CPF No. 5-2009-0018, at 4, 2013 WL 5883403, at *3 (Aug. 30, 2013) (finding new information that relates to PHMSA's authority to regulate the pipeline).

[20] PostRock KPC Pipeline, LLC, CPF No. 3-2011-1014, at 2, 2013 WL 8284478, at *2 (Dec. 5, 2013) (finding new information that the respondent had been purchased by another company).

[21] ExxonMobil Pipeline Co., CPF No. 4-2011-5016, at 3, 2014 WL 4635422, at *2 (Jul. 9, 2014) (considering new charts that were previously unavailable).

c. *Assertion That PHMSA Omitted Other Evidence*

Thirdly, Petitioner argued that the Final Order failed to mention another ERW study and failed to mention EMPCo's Root Cause Failure Analysis (RCFA).

The ERW study referenced by Petitioner is the *Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase I, Battelle* (Oct. 23, 2013) (Battelle Report). Petitioner did not provide a copy of the report for the record, but noted it was publically available.[22] EMPCo referenced the report for its position that current technologies and methods are still unable to address or predict all ERW pipeline risks.[23] Like the Battelle Report, EMPCo's RCFA was referenced in earlier submissions, but a copy was not submitted for consideration.[24] Petitioner contended the RCFA supported its position that the anomaly which led to the March 29, 2013 pipeline accident was unique and could not readily be detected.

The question of whether current technologies would have detected the anomaly that ultimately led to the Mayflower accident was not an issue decided in connection with the findings of violation in the Final Order. It is not clear how the Battelle Report and RCFA supported EMPCo's position that it complied with the pipeline safety regulations. Also, the Battelle Report was issued after the relevant facts of this case transpired. Given their relevance was not apparent with regard to the determinative issues, Petitioner's argument is rejected.

d. *Assertion That EMPCo Complied with § 195.452(e)(1)*

Finally, Petitioner argued the Final Order is flawed because the record reflected that EMPCo properly considered the susceptibility of the Pegasus Pipeline to seam failure in accordance with the regulation and industry reports.

As already discussed in the Final Order and above, EMPCo did not properly consider the factors in § 195.452(e)(1). Results of the previous assessments, pipe material, manufacturing information, seam type, and leak history pointed to seam failure susceptibility. EMPCo based its own conclusion largely on the absence of fatigue associated with prior seam failures, but that was not an acceptable basis for its conclusion, particularly since it did not fully consider the reasons fatigue may not have been present. Petitioner's assertion that the toughness of the pipe seam was "not relevant" to this analysis is rejected for the reasons set forth in the Final Order and this Decision.[25]

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[22] The document is referenced as EMPCo Hearing Exhibit 66 on a list of exhibits included by reference only. Post-hearing Submission Index of Attached Exhibits at 2.

[23] Post-hearing Submission at 4 and 15; Petition at 9.

[24] The document is reference as EMPCo Hearing Exhibit 56 on a list of exhibits included by reference only. Prehearing Submission Index of Attached Exhibits at 3.

[25] Petition at 12. *See* Hearing Transcript at 120-126 (discussing metallurgical reports finding no evidence of fatigue, but noting there was low toughness that would not be associated with fatigue).

Petitioner also argued that it appropriately used the PipeLife fatigue analysis program to form its conclusion regarding seam failure susceptibility. The program, Petitioner explained, was based on the toughness associated with ductile pipe and that fatigue failures "initiate in the heat-affected base metal that tends to exhibit ductile behavior."[26]

PHMSA affirms its finding that the fatigue analysis program was not appropriately used for the purpose of determining seam failure susceptibility. While the software program may be acceptable for determining reassessment intervals, including reassessment intervals for pipe with varying levels of toughness, calculating a reassessment interval is not the same as determining a pipeline's susceptibility to seam failure. A calculated reassessment interval greater than five years does not necessarily mean the pipeline is not susceptible to seam failure or is not required to be assessed for seam integrity.

In conclusion, while the performance regulation at § 195.452(e)(1) is not limited to only one process that must be used by operators for determining seam failure susceptibility in connection with a continual assessment schedule, the regulation does list the factors that must be considered. Operators are required to consider the factors accurately and appropriately, without dismissing probative information. Because PHMSA finds EMPCo reached a conclusion regarding the Pegasus Pipeline that did not appropriately consider the factors, including history of seam failures on the pre-1970 ERW pipe, PHMSA affirms the finding in the Final Order that Petitioner violated § 195.452(e)(1) by failing to establish an integrity assessment schedule that accounted for the risk of seam failure.

Item 2 in the Final Order found that EMPCo violated § 195.452(j)(3) by failing to perform an integrity assessment of the Pegasus Pipeline at an interval not to exceed five years or 68 months using a method capable of assessing seam integrity.

In its Petition, EMPCo argued the pipeline was not determined to be susceptible to seam failure, and, therefore, the Company was not required to perform an integrity assessment within five years using a method capable of assessing seam integrity. Petitioner's arguments for withdrawing the violation in Item 2 and for withdrawing most of the other violations duplicate the arguments the Company raised in response to the Notice, which were addressed in the Final Order. EMPCo is advised that it is not an appropriate use of a petition for reconsideration to repeat arguments that were already made by Petitioner in the hearing stage and addressed in the Final Order. Finding no reason to disturb the finding in the Final Order with respect to Item 2, PHMSA affirms the violation of § 195.452(j)(3).

Item 3 in the Final Order found EMPCo violated § 195.452(b)(5) when it failed to notify OPS that the Company planned to exceed the five-year interval for performing a seam integrity assessment.

In its Petition, EMPCo contended the pipeline was not determined to be susceptible to seam failure, and, therefore, the Company was not required to notify OPS when it decided to reschedule the seam integrity assessment. Again, this argument was raised in response to the

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[26] Petition at 13.

Notice and has already been addressed in the Final Order. PHMSA affirms the violation that Petitioner did not comply with § 195.452(b)(5).

Item 4 in the Final Order found that EMPCo violated § 195.452(e)(1) by failing to properly prioritize its pipeline segments for reassessment when it performed a seam integrity assessment of the Patoka to Conway segment in 2010, but waited until 2012–2013 to perform the same assessment on the Conway to Corsicana segment where the Mayflower accident occurred.

In its Petition, EMPCo argued that the regulation allows operators to decide how to assign risk scores and how to prioritize assessments. Petitioner argued the lower theoretical fatigue and higher number of girth weld leaks on the Patoka to Conway segment justified its decision to prioritize that segment for assessment.

This argument was raised in response to the Notice and was addressed in the Final Order. PHMSA determined the segments were improperly prioritized because the Conway to Corsicana segment had experienced more than double the number of seam failures from 1969 to 2006, recent failures had occurred on the segment at lower test pressures, and the segment had significantly more higher-risk ERW pipe. Finding no reason to disturb the findings in the Final Order, PHMSA affirms the violation of § 195.452(e)(1).

Item 5 in the Final Order found that EMPCo violated § 195.452(h)(1) by failing to temporarily reduce operating pressure or shut down its pipeline until certain repairs were completed. In its Petition, EMPCo contended the finding of violation is in error because the conditions were not identified as immediate repair conditions and, furthermore, were repaired "more quickly" than the Company could have implemented a pressure restriction.[27]

As discussed in the Final Order, once an immediate repair condition is identified, the regulation imposes a mandatory duty on the operator to temporarily reduce operating pressure or shut down the pipeline until the condition is repaired. Upon reconsideration, PHMSA continues to find the evidence demonstrates EMPCo discovered three immediate repair conditions as a result of an integrity assessment, and failed to temporarily reduce operating pressure or shut down the pipeline until the repairs were completed several days later. Finding no reason to disturb the findings in the Final Order, PHMSA affirms the violation of § 195.452(h)(1).

Item 6 in the Final Order found that EMPCo violated § 195.452(h)(2) by failing to obtain information about the condition of its pipeline no later than 180 days after an integrity assessment, unless the 180-day period was impracticable. EMPCo acknowledged that information was obtained weeks or months after the 180-day deadline, but argued it was impracticable because the results of the assessment were not timely received from the tool vendor. The Final Order rejected this argument, finding the Company bore the risk of its decision to double the length of its tool runs thereby increasing the amount of information that would have to be processed and reported within the regulatory deadline.

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[27] Petition at 16.

In its Petition, EMPCo argued the regulation at issue does not dictate the length of a tool run and the tool vendor had contractually agreed to provide the information within the required time. EMPCo also argued that the Final Order is contrary to public policy "by undermining the provisions of a bargained for contract."[28]

Although PHMSA has previously suggested that delay by a tool vendor might render discovery within 180 days impracticable, an operator's claim of impracticability requires considering all the relevant facts of the delay. Where an operator's actions contributed to the delay, as in the present case, PHMSA does not find the operator is excused from compliance due to an impracticability.

PHMSA also rejects Petitioner's contention that this would impact the ability of operators to rely on contractual commitments with their vendors. The pipeline safety regulations already resolve this issue by making it clear that when an operator arranges with another person for the performance of an action required under the regulations, the operator "is not thereby relieved from the responsibility for compliance."[29] Moreover, PHMSA has previously explained to Petitioner that employment of a contractor does not shield EMPCo from liability for failing to comply with the regulations.[30] Finding no reason to change the findings in the Final Order, PHMSA affirms the violation of § 195.452(h)(2).

Item 7 in the Final Order found that EMPCo violated § 195.452(b)(5), which requires pipeline operators to implement and follow provisions in their IMP. The Final Order determined that EMPCo violated the regulation by failing to follow its procedures for identifying changed conditions and its procedures for determining if changes require updating the risk assessment.

In its Petition, EMPCo contended that its procedures did not require updating the risk assessment because the Company was not required to perform a TFI tool run. This argument was raised in response to the Notice and was rejected in the Final Order. Finding no reason to modify the finding in the Final Order, PHMSA affirms the violation of § 195.452(b)(5).

Item 8 in the Final Order found that EMPCo violated §§ 195.402(a) and 195.452(b)(5). Section 195.402(a) requires operators to follow their operations and maintenance procedures, including procedures for integrity management. Section 195.452(b)(5) requires operators to follow their integrity management procedures specifically. The Final Order found EMPCo had failed to follow procedures associated with its integrity management program when it did not follow instructions for using its Threat Identification and Risk Assessment (TIARA) program.

In its Petition, EMPCo argued the violation was improperly alleged, and moreover, the Company properly recognized the risks associated with ERW pipe on the Pegasus Pipeline. These

[28] Petition at 18.

[29] § 195.10.

[30] ExxonMobil Pipeline Co., CPF No. 4-2004-5004, at 4, 2009 WL 7796890, at *3 (May 18, 2009), *citing* Williams Gas Pipeline - Transco, CPF No. 1-2005-1007, at 4, 2007 WL 2475903, at *4 (Jul. 18, 2007) (finding an operator "is responsible for the acts and omissions of its employees, agents, and contractors, including surveyors and inspectors.")

arguments were raised in response to the Notice and were already addressed in the Final Order. PHMSA affirms its finding that EMPCo violated §§ 195.402(a) and 195.452(b)(5).

Item 9 in the Final Order found that EMPCo violated § 195.452(b)(5) by failing to implement and follow provisions of its IMP related to documenting management of change (MOC) when merging four testable segments into two.

In its Petition, EMPCo contended that the violation is in error because EMPCo created two MOC forms to support its decision to merge the testable segments, and the forms addressed the merger's impact on integrity assessments. EMPCo also argued that PHMSA did not consider the inability of the Company's TIARA system to dilute risk over merged segments, and that PHMSA ignored the 2005 risk analysis that concluded the merger of testable segments would not impact the integrity management process.

These arguments were raised in response to the Notice. As discussed in the Final Order, the evidence submitted for Item 9 was reviewed to determine whether EMPCo created MOC documentation for the merger of the testable segments. Another review of the MOC forms reveals no discussion or analyses relevant to the merger of the testable segments at issue. PHMSA continues to find EMPCo failed to implement and follow provisions of its IMP related to MOC in violation of § 195.452(b)(5).

II. Petition to Withdraw or Reduce Civil Penalty and Compliance Order and Other Arguments

In its Petition, EMPCo raised several additional arguments concerning the Compliance Order, civil penalty, and fairness of the proceeding. These arguments are addressed below.

a. Compliance Order

EMPCo argued the Compliance Order should be withdrawn because the Company committed no violations. In the alternative, EMPCo argued the Compliance Order is overbroad and an abuse of discretion because some provisions apply to all pre-1970 ERW pipe subject to the Company's IMP, not just the Pegasus Pipeline.

The Final Order addressed both of these arguments and explained how the provisions are within the authority of PHMSA to issue orders directing compliance with the integrity management regulations. The Final Order also found the corrective actions were appropriately tailored to ensure EMPCo considers the risk of seam failures on its pre-1970 ERW pipe covered by the regulation. PHMSA finds no reason to modify the Compliance Order.

b. Civil Penalty

EMPCo argued that the civil penalty should be withdrawn or reduced because a number of the allegations constituted a single "series of violations" for which their combined penalties must be capped under 49 U.S.C. § 60122. This argument is addressed in the Final Order and Petitioner did not submit anything new in this regard. The decision in the Final Order regarding related violations is not modified.

EMPCo also argued the civil penalty should be withdrawn or reduced because there is no proof that Items 1, 2 and 8 were causal factors of the Mayflower accident. To support this assertion, Petitioner noted that no actionable anomaly was detected on the pipeline at the location of the failure when the Company performed an integrity assessment in 2012–2013. In addition, EMPCo argued the cause of the failure was unique and not capable of reliable detection.

Although no anomaly was previously detected at the failure location using a TFI tool, there were questions raised during the proceeding about the appropriateness of using a TFI tool in the first place, given that the types of defects detected by hydrostatic tests in 2005–2006 would not likely be detected with a TFI tool.[31] The evidence also suggested the test pressure during the 2005–2006 hydrostatic test may not have reached recommended levels for evaluating seam integrity at the location of the failure.[32] While the Final Order did not decide if hydrostatic testing would have detected the anomaly that failed, the fact that it was not detected does not negate the contributory impact of the violations.

Failure by EMPCo to recognize the risks of seam failure, to carry out an assessment schedule based on those risks, and to follow its procedures for assessing the risk of the pipeline, are all regulatory violations representing an overall failure by EMPCo to take preventative actions to avoid the specific type of accident that eventually occurred on the Pegasus Pipeline.[33] For these reasons, PHMSA affirms the finding in the Final Order that the violations contributed to the accident.

c. Due Process

EMPCo argued the Final Order violates due process and the Administrative Procedure Act (APA) because PHMSA does not provide meaningful guidance about how it assesses civil penalties and because the Agency did not provide a copy of the Presiding Official's recommended decision.

"Without the benefit of a published penalty policy," Petitioner argued, "pipeline operators have no means of contesting the various considerations that may inform a PHMSA penalty assessment."[34] EMPCo noted that many other federal agencies have implemented public policies

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[31] Region Recommendation at 9. *See* Accident Report, Appendix E, at b (Oct. 23, 2013) (asserting the most effective assessment method was hydrotest until it could be shown that in-line inspection tools were capable of detecting the type of ERW seam flaws present on the Pegasus Pipeline).

[32] The test in 2005–2006 was to 125% MOP. Final Order at 3. This is the minimum test pressure for establishing MOP under § 195.304, but hydrostatic tests to assess integrity commonly use 139% MOP or 153% MOP. *See* Accident Report, Exhibit E, Tab E at i (stating if lower stress level tests are chosen, a factor of 1.39 should be used). *See also Spike Hydrostatic Test Evaluation* by Michael Baker Jr., Inc. (July 2004) at 57 (stating that two values of test pressure commonly used are 1.39 times MOP and 1.53 times MOP) *available at:* https://primis.phmsa.dot.gov/iim/techreports.htm.

[33] *See, e.g.*, Accident Report at 8 (stating that if the IMP requirements were "executed properly, it would have been far less likely for the accident to occur, and thus [the actions by EMPCo] are found to be contributory to the primary cause of the accident").

[34] Petition at 22.

that describe their civil penalty assessment processes, yet the PHMSA Office of Pipeline Safety has never adopted comparable guidelines.

PHMSA responded to this argument in the Final Order. The civil penalty assessment factors that must be considered are set forth in 49 U.S.C. § 60122 and 49 C.F.R. § 190.225. PHMSA has given additional definition to these factors by explaining what type of conduct, evidence, and facts are relevant to each factor. The explanations appear in previously-issued final orders, in the Violation Report provided to EMPCo in this case, and in a three-page Civil Penalty Summary document that EMPCo acknowledged receipt of.[35]

In the Violation Report, each required assessment factor is considered separately using a list of possible descriptions that range in severity. In preparing the report, OPS selected one description under each assessment factor that allegedly represented the relevant facts supported by evidence for that violation. For example, under gravity for Item 9, OPS selected the description that "pipeline safety or integrity was significantly compromised in an HCA or an HCA could affect segment."[36] This description is slightly more than halfway between the least and most severe gravity descriptions in the Violation Report and Civil Penalty Summary document.

The Civil Penalty Summary document also discusses the penalty assessment factors. It explains the range of penalties that may be assessed under each factor and the type of evidence or facts that will result in higher or lower penalties under each assessment factor. This information corresponds directly to the particular facts noted in the Violation Report, which contained the factual allegations and description selections for each violation.

Through the Violation Report, EMPCo was apprised of the factual material OPS believed to be relevant to the proposed civil penalty. The Company also knew how OPS viewed those facts as to the severity of the gravity, culpability, and other factors. EMPCo had an opportunity to offer its own contrary presentation of any or all of the relevant factual material impacting the penalty. The Final Order considered the information offered by both OPS and EMPCo in deciding an appropriate civil penalty under the assessment factors. Since EMPCo knew the factors that must be considered and the information that was relevant to those factors, the Company had access to sufficient information about the proposed penalty to allow a meaningful and targeted response.

Regarding availability of the Presiding Official's recommended decision, Petitioner acknowledged that PHMSA has previously declined to make recommended decisions part of the case file because the document is considered to be an "internal and deliberative communication or 'draft decision.'"[37] Petitioner argued the APA "prohibits such internal ex parte communications between an agency and its decision maker in an adjudicative matter."[38] To support its argument, the Company cited *United States Lines, Inc., v. Federal Maritime*

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[35] *See Administrative Procedures; Updates and Technical Corrections*, 78 Fed. Reg. 58897, 58901 (Sept. 25, 2013) (explaining that a general outline of how penalties are calculated can be provided upon request).

[36] Violation Report at 62.

[37] 78 Fed. Reg. at 58901.

[38] Petition at 22.

Commission, 584 F.2d 519 (D.C. Cir 1978). Petitioner argued that without disclosure of the recommended decision, there is no opportunity for the Company to rebut it.

In the case cited by Petitioner, a court reversed an adjudicatory decision by a federal agency, in part, because the agency had based its decision on *ex parte* communications with only one of the parties. The *ex parte* contacts had introduced new arguments and positions that responded to and rebutted arguments of the other party. The court found use of the secret communications by the decision maker was inconsistent with a fair hearing under the APA.

That case differed, of course, from the current proceeding where there is no allegation of an *ex parte* contact between one of the parties and the Presiding Official or Associate Administrator regarding an issue to be decided in the proceeding. Both parties' final written submissions were made part of the record in the case and shared with the other party. Since no *ex parte* communication occurred, Petitioner's argument is rejected.

Petitioner's implication that the recommended decision itself may constitute an *ex parte* communication must also be rejected. It is the statutory role of the Presiding Official to consider the record in the case and to deliver a recommended decision to the Associate Administrator who issues a final order. The process appropriately falls within the scope of informal adjudication permitted under the APA, even though it may differ from another agency's enforcement process. For example, Petitioner cited to the procedures of the Environmental Protection Agency in 40 C.F.R. Part 22, under which an Administrative Law Judge issues an "initial decision" that becomes the agency's final decision unless one of the parties moves to reopen the record or appeals the initial decision to the Environmental Appeals Board.

PHMSA's informal adjudication process is obviously different. PHMSA has been pointed to no authority that requires modification of its process in the manner Petitioner has suggested. Petitioner had a full opportunity to respond to material in the record, and even sought reconsideration of the Final Order through filing of its Petition. For the above reasons, Petitioner's arguments are rejected.

d. Other Arguments

EMPCo repeated its argument that the Pipeline Safety Act does not create strict liability for pipeline accidents, and argued the Agency failed to meet its burden of proof. These arguments are sufficiently addressed by the Final Order.

III. Conclusion

The Petition for Reconsideration filed by EMPCo is ***denied***. Payment of the $2,630,400 civil penalty assessed in the Final Order is now due and must be made within 20 days of service of this Decision.

Federal regulations (49 C.F.R. § 89.21(b)(3)) require such payment to be made by wire transfer through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMK-325), Federal Aviation

Administration, ATTN: Shelby Jones, 6500 S MacArthur Blvd., Oklahoma City, Oklahoma 79169. The Financial Operations Division telephone number is (405) 954-8845.

Failure to pay the $2,630,400 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Failure to pay the civil penalty may result in referral of the matter to the Attorney General for action in a district court of the United States.

The stay of the Compliance Order that was issued by PHMSA on November 4, 2015, and extended on February 4, 2016, is hereby terminated. The deadlines within the Compliance Order will be calculated from the date of issuance of this Decision. All other terms of the Final Order, including terms of the Compliance Order not otherwise modified, remain in effect. This Decision constitutes final agency action in this enforcement proceeding.

APR 01 2016

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Date Issued

Tab 3

REGULATIONS AT ISSUE

Text of 195.452(e)(1):

> (e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:
>
>> (i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
>>
>> (ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;
>>
>> (iii) Leak history, repair history and cathodic protection history;
>>
>> (iv) Product transported;
>>
>> (v) Operating stress level;
>>
>> (vi) Existing or projected activities in the area;
>>
>> (vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
>>
>> (viii) geo-technical hazards; and
>>
>> (ix) Physical support of the segment such as by a cable suspension bridge.

Text of 195.452(j)(3):

> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—. . . (3) Assessment intervals. An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must

> base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

Text of 195.452(b)(5):

> (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:
>
> > (5) Implement and follow the program.

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by a State, to the appropriate State agency.

(j) *Compliance and deviations.* An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of the pipeline facility.

[Amdt. 195–93, 74 FR 63329, Dec. 3, 2009, as amended at 75 FR 5537, Feb. 3, 2010; 76 FR 35135, June 16, 2011]

HIGH CONSEQUENCE AREAS

§ 195.450 Definitions.

The following definitions apply to this section and § 195.452:

Emergency flow restricting device or *EFRD* means a check valve or remote control valve as follows:

(1) *Check valve* means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction.

(2) *Remote control valve* or *RCV* means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

High consequence area means:

(1) A *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists;

(2) A *high population area*, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

(3) An *other populated area*, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;

(4) An *unusually sensitive area*, as defined in § 195.6.

[Amdt. 195–70, 65 FR 75405, Dec. 1, 2000]

PIPELINE INTEGRITY MANAGEMENT

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

(b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	1 year after the date the pipeline begins operation.

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	December 31, 2001.

Pipeline	Date
Category 2	November 18, 2002.
Category 3	Date the pipeline begins operation.

(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(4) Include in the program a framework that—

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

(ii) Initially indicates how decisions will be made to implement each element.

(5) Implement and follow the program.

(6) Follow recognized industry practices in carrying out this section, unless—

(i) This section specifies otherwise; or

(ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

(c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan:

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(B) Pressure test conducted in accordance with subpart E of this part;

(C) External corrosion direct assessment in accordance with §195.588; or

(D) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

(ii) A schedule for completing the integrity assessment;

(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

(d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows:

(1) *Time periods.* Complete assessments before the following deadlines:

If the pipeline is:	Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments:	And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than:
Category 1	March 31, 2008	September 30, 2004.
Category 2	February 17, 2009	August 16, 2005.
Category 3	Date the pipeline begins operation	Not applicable.

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows:

Pipeline	Date
Category 1	January 1, 1996.
Category 2	February 15, 1997.

(3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of

this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:

(i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;

(ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;

(iii) Leak history, repair history and cathodic protection history;

(iv) Product transported;

(v) Operating stress level;

(vi) Existing or projected activities in the area;

(vii) Local environmental factors that could affect the pipeline (*e.g.*, corrosivity of soil, subsidence, climatic);

(viii) geo-technical hazards; and

(ix) Physical support of the segment such as by a cable suspension bridge.

(2) Appendix C of this part provides further guidance on risk factors.

(f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

(1) A process for identifying which pipeline segments could affect a high consequence area;

(2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

(7) Methods to measure the program's effectiveness (see paragraph (k) of this section);

(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:

(1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;

(2) Data gathered through the integrity assessment required under this section;

(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and

(4) Information about how a failure would affect the high consequence area, such as location of the water intake.

(h) *What actions must an operator take to address integrity issues?*—(1) *General requirements*. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with §195.422 when making a repair.

(i) *Temporary pressure reduction*. An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure.

(ii) *Long-term pressure reduction*. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

(2) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

(3) *Schedule for evaluation and remediation*. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.

(4) *Special requirements for scheduling remediation*—(i) *Immediate repair conditions*. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in Section 451.6.2.2 (b) of ANSI/ASME B31.4 (incorporated by reference, *see* §195.3). An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)). These documents are incorporated by reference and are available at the addresses listed in §195.3.

(C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *60-day conditions*. Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

(iii) *180-day conditions*. Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(D) A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991)) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)). These documents are incorporated by reference and are available at the addresses listed in §195.3.

(E) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(H) Corrosion of or along a longitudinal seam weld.

(I) A gouge or groove greater than 12.5% of nominal wall.

(iv) *Other conditions*. In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*—(1) *General requirements*. An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

(2) *Risk analysis criteria*. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a

pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

(3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors—length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

(4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

(j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*—(1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.

(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) *Assessment intervals.* An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

(4) *Variance from the 5-year intervals in limited situations*—(i) *Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a

longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

(ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address specified in paragraph (m) of this section.

(5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(ii) Pressure test conducted in accordance with subpart E of this part;

(iii) External corrosion direct assessment in accordance with § 195.588; or

(iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

(k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

(l) *What records must be kept?* (1) An operator must maintain for review during an inspection:

(i) A written integrity management program in accordance with paragraph (b) of this section.

(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

(2) See Appendix C of this part for examples of records an operator would be required to keep.

(m) *How does an operator notify PHMSA?* An operator must provide any notification required by this section by:

(1) Entering the information directly on the Integrity Management Database Web site at *http://primis.phmsa.dot.gov/imdb/;*

(2) Sending the notification to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE., Washington, DC 20590; or

(3) Sending the notification to the Information Resources Manager by facsimile to (202) 366–7128.

[Amdt. 195–70, 65 FR 75406, Dec. 1, 2000, as amended by Amdt. 195–74, 67 FR 1660, 1661, Jan. 14, 2002; Amdt. 195–76, 67 FR 2143, Jan. 16, 2002; 67 FR 46911, July 17, 2002; 70 FR 11140, Mar. 8, 2005; Amdt. 195–85, 70 FR 61576, Oct. 25, 2005; Amdt. 195–87, 72 FR 39017, July 17, 2007; 73 FR 16571, Mar. 28, 2008; 73 FR 31646, June 3, 2008; Amdt. 195–94, 75 FR 48607, Aug. 11, 2010]

Subpart G—Qualification of Pipeline Personnel

SOURCE: Amdt. 195–67, 64 FR 46866, Aug. 27, 1999, unless otherwise noted.

§ 195.501 Scope.

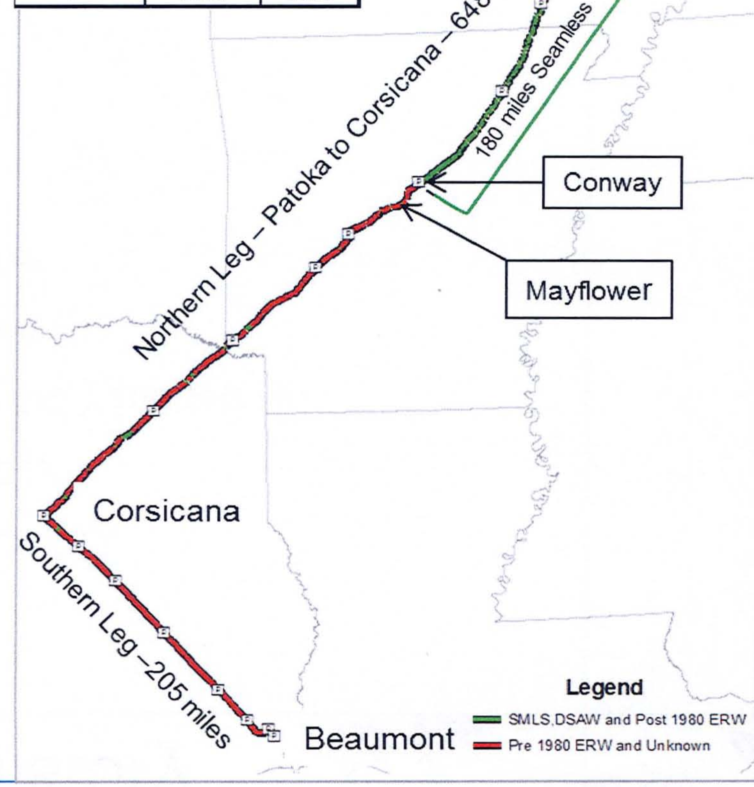
(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

Tab 4

Pegasus System Overview

- Northern Leg – 648 miles
  - Commissioned in 1948, shutdown in 2002, reversed in 2006, expanded in 2009
  - Recent seam In Line Inspection (ILI) tool: 2010 - 2013
- Southern Leg to Beaumont – 205 miles
  - Commissioned in 1955, Reversed in 2006, expanded in 2013
  - Recent seam ILI tool: 2003
- Current Line Status/Actions
  - Line inactive containing inhibited crude since March 29, 2013
  - Internal and External corrosion control monitoring ongoing

	North Leg	South Leg
Diameter	20"	20"
Year / Manufacturer	1947 / Youngstown	1954 / A.O. Smith
LF-ERW* pipe (miles)	410	205
Max Op Pressure	820 psi	1020 psi
Hydrotest	2006	1991

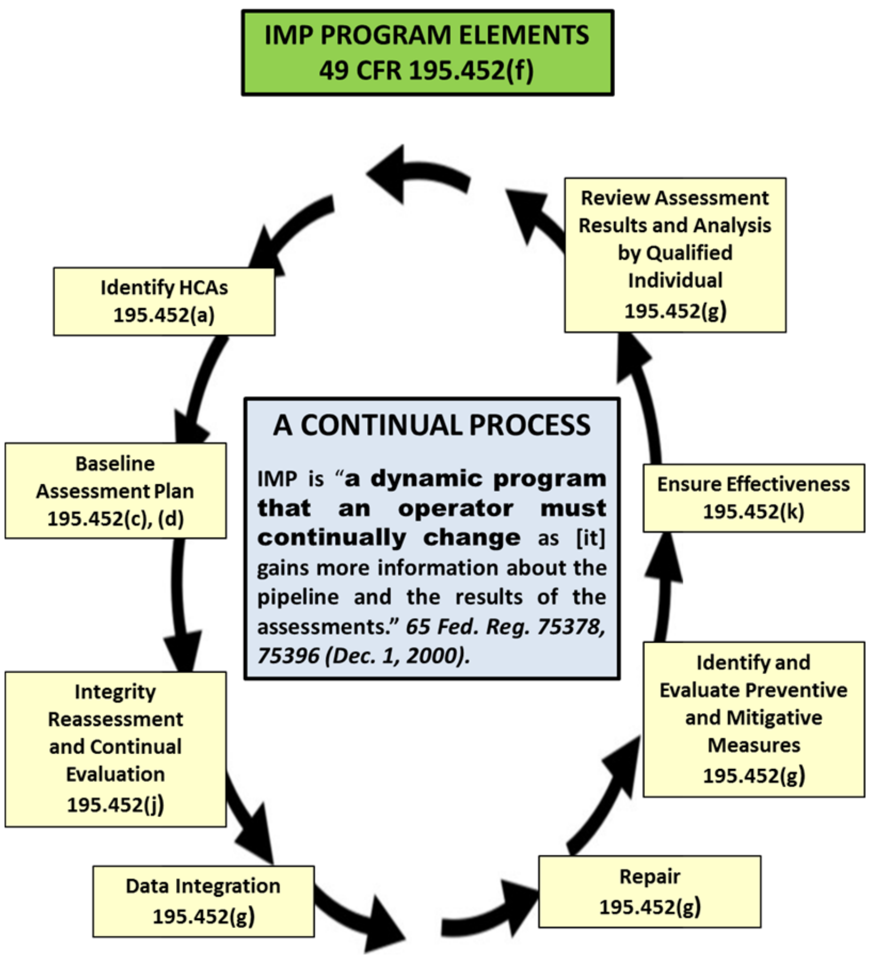


Tab 5

to reflect pipeline specific conditions and risks. Performance based standards allow an operator to select the most effective processes and technologies as they become available.”).

Under these rules, which first became effective in 2001, operators were required to develop a written IMP plan that included the following: (1) identification of pipelines that could affect sensitive areas called high consequence areas (HCAs); (2) a baseline assessment plan (BAP) for initial assessments of those lines; (3) procedures for the integration of all available information about pipeline integrity and the consequences of a failure; (4) prompt action to address issues identified by the assessment and prioritization of repairs; (5) reassessment at least every five years; (6) continual evaluation to include additional preventive and mitigative measures as appropriate; (7) methods to measure effectiveness; and (8) a process for review of the assessment results by a qualified individual. *49 C.F.R. Part 195.452(f); see Figure 2: IMP Program Elements.*

Figure 2: IMP Program Elements, 49 CFR Part 195.452(f)



While the rule prescribes which program components are required, its performance based elements allow operators discretion in how to implement these components. For that reason, PHMSA anticipated that this would be an evolving “dynamic” iterative process for both operators and the industry, and the agency continues to emphasize that point. *Final Rule, 65 Fed. Reg. 75378, 75386 (Dec. 1, 2000); see also PHMSA Advisory, 79 Fed. Reg. 25900, 25993*

Tab 6

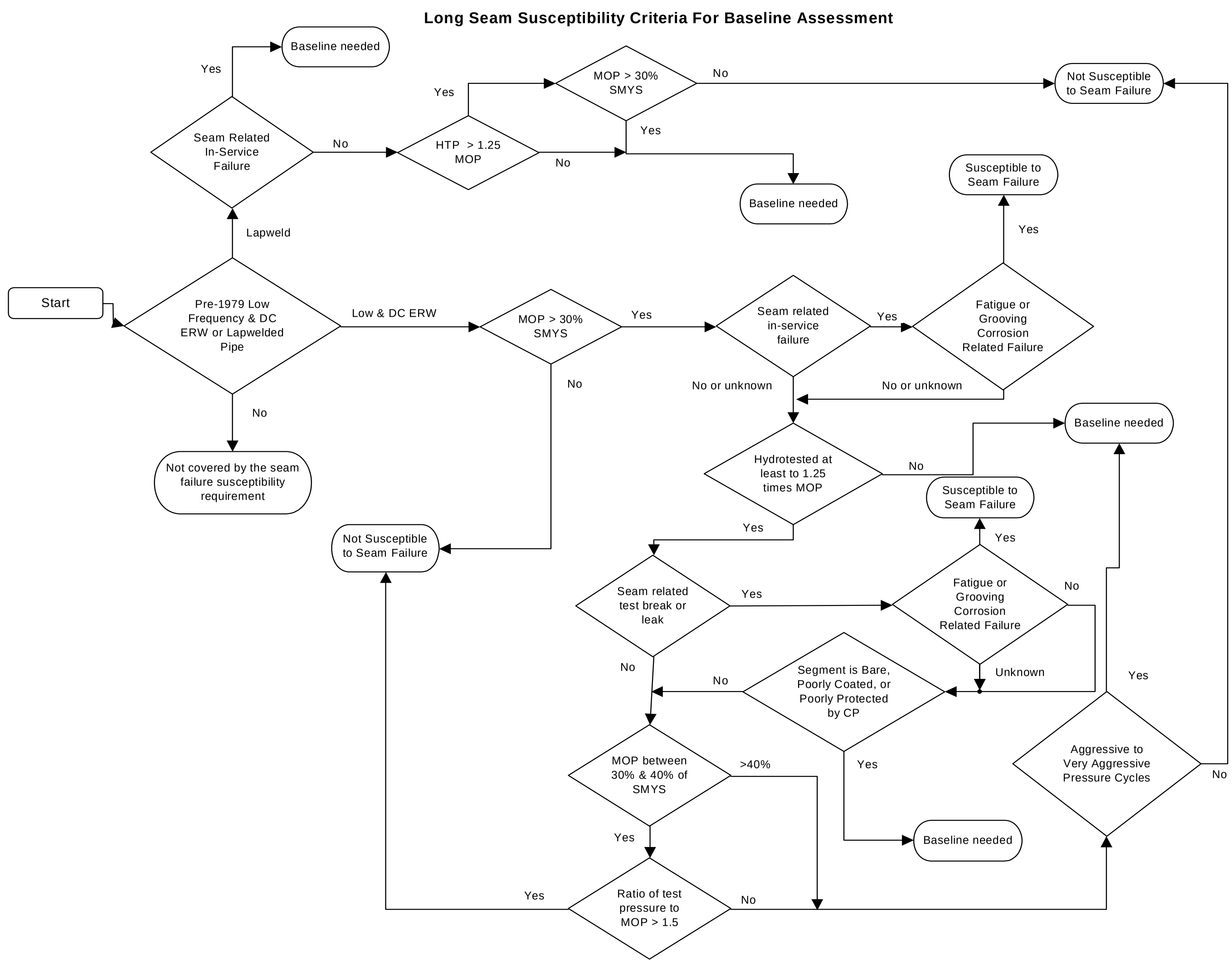


Figure 4.1 Framework for Evaluation

Tab 7

Figure 3

EMPCo Integrity Assessment and LSFSA Analysis: Conway to Foreman (prior to March 29, 2013 Mayflower Incident at MP 314.77)