



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

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

OCT 01 2015

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 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,

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

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.

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,

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

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.

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-induced 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

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

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 as 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

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.

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).

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

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.

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

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

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.

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.

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*

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.

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 consider 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

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

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.

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

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

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 PHMSA to apply a compliance order in this case to company assets that were not involved 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.

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.

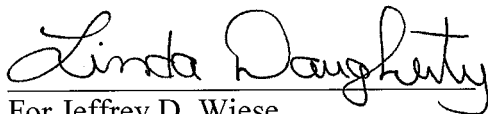
5. With respect to the violations of §§ 195.452(h)(1) and (h)(2) (**Items 5 and 6**), EMPCo must conduct an internal investigation of the ability of its OIMS, IMP and interrelated management processes to adequately identify and assess the risk of, and take appropriate risk reduction activities to address 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.



For Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

OCT 01 2015

Date Issued