JUNE 27, 2013

Mr. Gary Pruessing
President
ExxonMobil Pipeline Company
800 Bell St., Room 741-D
Houston, TX 77002

Re: CPF No. 4-2011-5016

Dear Mr. Pruessing:

Enclosed please find the Final Order issued in the above-referenced case. It makes findings of violation, assesses a reduced civil penalty of $112,300, withdraws several alleged violations, 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 the Final Order is made pursuant to 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. R.M. Seeley, Director, Southwest Region, OPS
Mr. Alan Mayberry, Deputy Associate Administrator for Field Operations, OPS
Ms. Catherine Little, Hunton & Williams LLP, Bank of America Plaza, Suite 4100
600 Peachtree Street, N.E., Atlanta, GA 30308

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

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

In the Matter of	)	
ExxonMobil Pipeline Company,	)	**CPF No. 4-2011-5016**
Respondent.	)	

FINAL ORDER

On March 31-April 1, 2011, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), conducted an on-site pipeline safety inspection of the records and procedures of ExxonMobil Pipeline Company (EMPCo or Respondent) in Houston, Texas. EMPCo, a subsidiary of Exxon Mobil Corporation, operates approximately 4,000 miles of pipeline transporting crude oil, refined petroleum products, and highly volatile liquids in Texas, Louisiana, and Montana.[1]

As a result of the inspection, the Director, Southwest Region, OPS (Director), issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) to Respondent on November 7, 2011. In accordance with 49 C.F.R. § 190.207, the Notice alleged that Respondent committed violations of the pipeline safety regulations in 49 C.F.R. Part 195 and proposed a total civil penalty of $151,100 for the alleged violations. The Notice also proposed corrective action to be completed.

EMPCo responded to the Notice by letter dated December 15, 2011 (Response). In its Response, Respondent contested the alleged violations and requested a hearing. Respondent provided additional written explanations by letter dated April 16, 2012. A hearing was held in accordance with 49 C.F.R. § 190.211 on April 25, 2012, in Houston, Texas, before the Presiding Official from the Office of Chief Counsel, PHMSA. After the hearing, Respondent submitted additional written material by letters dated June 29 and August 30, 2012.

FINDINGS OF VIOLATION

The Notice alleged that Respondent violated 49 C.F.R. Part 195, as follows:

[1] Pipeline system information for calendar year 2011 was reported by EMPCo pursuant to 49 C.F.R. § 195.49.

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.302, which states, in relevant part:

> **§ 195.302 General requirements.**
> (a) [N]o operator may operate a pipeline unless it has been pressure tested under this subpart without leakage . . . .
> (c) Except for pipelines . . . covered under § 195.303, the following compliance deadlines apply to pipelines . . . that have not been pressure tested under this subpart . . .
> (2) For pipelines scheduled for testing, each operator shall—
> (i) Before December 7, 2000, pressure test—
> (A) Each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and
> (B) At least 50 percent of the mileage (length) of all other pipelines; and
> (ii) Before December 7, 2003, pressure test the remainder of the pipeline mileage (length).

The Notice alleged that Respondent violated § 195.302 by operating 27 pipeline segments that had not been pressure tested by the deadlines set forth in the regulation. OPS included in the record evidence of a spreadsheet prepared by Respondent titled, "Systems Lacking DOT Hydrotest Documentation" (Spreadsheet), which listed 27 pipeline segments totaling 615.7 miles. [2]

In its written submissions prior to the hearing, Respondent explained that the Spreadsheet had been prepared in 1998 as part of its effort to comply with the deadline in 49 C.F.R. § 195.302. Respondent produced information regarding the current status of the 27 pipeline segments. Respondent contended that: (a) twelve were pressure tested; (b) five were purged of product and idled; (c) two were sold; (d) five were exempt from § 195.302 because they were covered under § 195.303; and (e) three were exempt from Part 195 altogether.[3] At the hearing, Respondent discussed in more detail the eight segments that it claimed were exempt. Respondent provided a post hearing submission with additional records regarding all 27 segments.

Applicable safety standards

Beginning in 1971, each newly constructed pipeline transporting hazardous liquids was required to undergo a pressure test in accordance with 49 C.F.R. Part 195, Subpart E. In 1994, the pressure testing requirements were extended to all hazardous liquid pipelines, including those constructed before 1971. Deadlines for testing older pipelines were established in § 195.302(c)(2). In 1998, § 195.303 was adopted to allow operators of older pipelines to elect an alternative testing and inspection program to evaluate the integrity of the lines based on individual risk factors.

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[2] OPS Pipeline Safety Violation Report, Exhibit 1-2 (Nov. 7, 2011) (Violation Report).

[3] EMPCo letter dated April 16, 2012, p.2 (Pre-hearing Submittal).

Certain record keeping requirements were established to ensure that any pressure test or alternative program complied with the applicable requirements. Operators were required to make and retain for each pressure test documentation including, among other things: pressure recording charts; test instrument calibration data; date and time of the test; minimum test pressure; a description of the facility tested; and temperature of the test medium or pipe during the test period.[4] If an operator elected to follow a risk-based alternative to pressure testing, § 195.303 required the operator to maintain records verifying the risk classifications, the plans and schedule for testing, the conduct of the testing, and ongoing review of risk classifications.

Findings

The following findings are made with regard to each of the 27 pipeline segments at issue. The segments are categorized by their alleged disposition according to Respondent. Next to each segment name is a number that corresponds to the order in which the segment was listed on the 1998 Spreadsheet.

a. ***Segments that Respondent Claimed Were Pressure Tested***

PCU to Mt. Belvieu Poly Propylene (Segment 2)

Respondent contended that the PCU to Mt. Belvieu Poly Propylene pipeline segment was pressure tested in 1981, 2004, and 2009, and therefore the segment was in compliance with § 195.302 at the time of the OPS inspection.

Respondent submitted a diagram of the Baytown PCU Polymer Grade Propylene System and records from pressure tests that took place in 1980 on the system.[5] Hand-drawn diagrams attached to the test records depicted about 750 feet of tested pipe. Respondent did not submit any test records from 2004 or 2009.

The 1998 Spreadsheet indicated the PCU to Mt. Belvieu Poly Propylene segment that did not have adequate pressure test documentation was 0.27 miles or approximately 1,427 feet in length. The evidence fails to demonstrate the entire 0.27-mile segment was pressure tested according to § 195.302. For this reason, I find the segment was not in compliance.

St. James to Junction (Segment 4)

Respondent contended that the St. James to Junction pipeline segment was pressure tested in 1968 and therefore the segment was in compliance with § 195.302 at the time of the OPS inspection. To support this contention, Respondent submitted a single page Pipeline Qualification Record dated 1968.[6]

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[4] § 195.310.

[5] EMPCo letter dated June 29, 2012, Exhibits 9 and 10 (Post-hearing Submission).

[6] Post-hearing Submission, Exhibit 18.

The record submitted by Respondent is not sufficient to demonstrate a pressure test was conducted in accordance with Subpart E because the record lacked necessary information such as a pressure recording chart. Without adequate documentation of a pressure test, I find this segment was not in compliance.

Webster to Baytown #3 and #6-8 inch (Segment 11)

Respondent contended that the Webster to Baytown #3 and #6-8 inch pipeline segment was pressure tested in 2000 and therefore was in compliance with § 195.302 at the time of the OPS inspection. Respondent also noted that this segment was idled after the OPS inspection.

Respondent submitted records from a pressure test that occurred in 2000.[7] These records are not sufficient to demonstrate a pressure test was conducted in accordance with Subpart E because the records did not include any pressure recording charts. In addition, the records did not reference the entire 1.08-mile Webster to Baytown #3 and #6-8 inch pipeline segment listed in the Spreadsheet. For these reasons, I find the segment was not in compliance.

BOP to ITC Butadiene (Segment 12)

Respondent contended that due to a naming discrepancy, this pipeline segment was either the BOP to ITC *Crude* Butadiene system, which was pressure tested in 1979 and 2003, or it was the BOP to ITC *Product* Butadiene system, which was pressure tested in 1981. Since both were pressure tested, Respondent contended the segment was in compliance with § 195.302 at the time of the OPS inspection.

Respondent submitted records from a pressure test that took place in 1979 on the "Chocolate Bayou—BOP Cr[ude] Butadiene Sys[tem] (ITC Lateral)."[8] Respondent also submitted records from a test that took place in 1980 on what appears to be a different pipeline, but not the *product* line referenced above. The segment tested in 1980 was the "Chocolate Bayou to Baytown Crude Butadiene."[9] Respondent did not submit any test records that could be identified for the BOP to ITC Product Butadiene system or any records from a pressure test in 2003.

The records submitted by Respondent are not sufficient to demonstrate that the pipeline segment referenced on the Spreadsheet was pressure tested in accordance with § 195.302 because the records submitted did not include any pressure recording charts. Accordingly, I find this segment was not in compliance.

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7 Post-hearing Submission, Exhibit 46.

8 Post-hearing Submission, Exhibit 53. Respondent submitted these records in duplicate for the Chocolate Bayou - BOP Crude Butadiene (Segment 24, *see* below), but did not explain why identical records were submitted for different pipeline segments.

9 Post-hearing Submission, Exhibit 54.

Boyce to Bunkie (Segment 14)

Respondent contended that the Boyce to Bunkie pipeline segment was pressure tested in 2000 or 2001 and therefore was in compliance with § 195.302 at the time of the OPS inspection. Respondent also noted that the segment was renamed Melville to Boyce after a reversal in 2001.

Respondent submitted records from two pressure tests that took place in 2001—one from Boyce to Chandler, which covered approximately 21 miles, and one from Chandler to Bunkie, which covered slightly less than 21 miles, for a total of about 42 miles.[10]

The evidence submitted by Respondent does not demonstrate the entire 46.3-mile segment listed in the Spreadsheet was pressure tested in accordance with Subpart E. Furthermore, the records were insufficient because they did not include any pressure recording charts. Accordingly, I find this segment was not in compliance.

Bunkie to Anchorage (Segment 15)

Respondent contended that the Bunkie to Anchorage pipeline segment was pressure tested in 2000 or 2001 and therefore the segment was in compliance at the time of the OPS inspection. Respondent noted this segment was renamed Anchorage to Melville and Melville to Boyce after a 2001 reversal.

Respondent submitted records from two pressure tests that took place in 2001—one from Bunkie to Hwy 361, which covered approximately 12.31 miles, and one from Hwy 361 to AR Melville West, which covered approximately 19.48 miles, for a total of about 32 miles.[11]

The evidence submitted by Respondent does not demonstrate the entire 51.41-mile segment listed in the Spreadsheet was pressure tested. Furthermore, the records were insufficient because they did not include any pressure recording charts. Accordingly, I find this segment was not in compliance.

Finney to Boyce (Segment 16)

Respondent contended that the Finney to Boyce pipeline segment was pressure tested in 2000 or 2001 and therefore the segment was in compliance at the time of the OPS inspection. Respondent also noted the segment was renamed Boyce to Finney after the 2001 reversal.

Respondent submitted records of pressure tests that took place in 2001.[12] The records were insufficient because they did not include any pressure recording charts. Accordingly, I find this segment was not in compliance.

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[10] Post-hearing Submission, Exhibits 58 and 59.

[11] Post-hearing Submission, Exhibits 62 and 63. Another record, Exhibit 64, appeared to concern a test on a different pipeline segment.

[12] Post-hearing Submission, Exhibit 68.

Strang Road to Texas City (Segment 21)

Respondent contended that the Strang Road to Texas City pipeline segment was pressure tested in 1997 and therefore the segment was in compliance at the time of the OPS inspection. Respondent also noted that this segment is now part of the Fairmont Junction to Texas City Propylene System.

Respondent submitted records from a pressure test that took place in 1997 at “various locations” on the “Bayport Jct. to Texas City section.”[13] An attachment to the test record indicated the test began at station 444+27 (valve 3506) and ended at station 1058+33 (valve 3524).[14] Respondent also submitted several pipeline diagrams.[15] The station and valve identification numbers from the test record did not appear to correlate to any one diagram in a manner that clearly demonstrated the 2.86-mile Strang Road to Texas City segment referenced in the Spreadsheet had been pressure tested. In addition, the pressure test records were insufficient because they did not include any pressure recording charts. Accordingly, I find this segment was not in compliance.

Texas Olefins Multi-Products Crossover (Segment 22)

Respondent contended that the Texas Olefins Multi-Products Crossover pipeline segment was pressure tested in 1982 and therefore the segment was in compliance at the time of the OPS inspection.

Respondent submitted records from a pressure test that took place in 1982 on the “BOP - Texas Olefins Spare Liquid Hydrocarbon Line.”[16] Respondent submitted a duplicate of this record for the BOP to Texas Olefins Raffinate segment (Segment 23, *see* below).

The station identification numbers from the 1982 test record did not appear to correlate to the diagram Respondent submitted for this segment. In addition, the records were insufficient because they did not include any pressure recording charts. Accordingly, I find this segment was not in compliance.

Chocolate Bayou BOP Crude Butadiene (Segment 24)

Respondent noted that due to a naming discrepancy, this pipeline segment is now part of the Chocolate Bayou - BPU Butylene System. Respondent contended that it was pressure tested in 1981 and therefore was in compliance at the time of the OPS inspection.

Respondent submitted records from a pressure test that took place in 1979 on the “Chocolate Bayou-BOP Cr. Butadiene Sys (ITC Lateral).” This same record was submitted by Respondent

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[13] Post-hearing Submission, Exhibit 85.

[14] Post-hearing Submission, Exhibit 86.

[15] Post-hearing Submission, Exhibit 84.

[16] Post-hearing Submission, Exhibit 90.

for the BOP to ITC Butadiene segment (Segment 12, *see* above). Several of the diagrams submitted for this segment were also duplicates.

As I have already determined for these records in regard to the BOP to ITC Butadiene segment, the records were insufficient to demonstrate a pressure test had been conducted in accordance with Subpart E because they did not include any pressure recording charts. For these reasons, I find this segment was not in compliance.

Clovelly to Raceland 16-inch Import (Segment 25)

Respondent contended that this pipeline segment was pressure tested in 1966 and therefore the segment was in compliance at the time of the OPS inspection.

Respondent submitted records from a pressure test that took place in 1966, which were attached to a report prepared in 1996. According to the report, the test "was performed on the 6.21 mile, #2-16[inch] pipeline segment from Clovelly Junction to LaRose Junction (Import System)."[17]

The evidence submitted by Respondent does not demonstrate the entire 16.79-mile segment listed in the Spreadsheet was pressure tested. For this reason, I find the segment was not in compliance.

Viola to Hess Refinery #2 - 6 inch Line (Segment 27)

Respondent contended that this pipeline segment was pressure tested in 1999 and 2011 and therefore it was in compliance at the time of the OPS inspection.

Respondent submitted records from pressure tests that took place in 1999 on the "Corpus Christi to King Ranch Gas Plant Propane System-Coastal States to Viola 6[-inch]" and the "King Ranch to Coastal States Propane System Viola to Coastal States 6[-inch]."[18] The records submitted were insufficient to demonstrate the pressure tests were conducted in accordance with Subpart E because they did not include any pressure recording charts. Respondent did not submit any records from a pressure test performed on this segment in 2011. Accordingly, I find this segment was not in compliance.

b. Segments that Respondent Claimed Were Idled Prior to the Inspection[19]

Avery Island to Lydia (Segment 6)

Respondent contended that the Avery Island to Lydia pipeline segment was idled in 2011, prior to the OPS inspection, and has since been abandoned. Respondent further contended that the

[17] Post-hearing Submission, Exhibit 99.

[18] Post-hearing Submission, Exhibit 104.

[19] Respondent contended in its Pre-hearing Submittal that five segments were in compliance because they had been purged of product and idled; however, the evidence produced suggested Respondent intended to make this claim for four segments.

segment was pressure tested in 2000 and 2005.

The pipeline safety regulations do not explicitly recognize a pipeline as “idled,” although the term is commonly used to refer to pipelines in which operations have been temporarily suspended.[20] Respondent stated that it uses the term to mean “deactivated and filled with nitrogen.”[21] The status of any one of the 27 pipeline segments as inactive or idled at the time of the OPS inspection does not by itself excuse noncompliance if Respondent had operated the pipeline without a pressure test in violation of § 195.302.

Respondent submitted a report from a pressure test that took place in 2000 on the Avery Island pipeline.[22] The test covered 49,210 feet of 6-inch pipe. Respondent also submitted some forms from a pressure test that was performed in 2005, although those records were incomplete.

The Avery Island to Lydia segment listed on the Spreadsheet was 8.16 miles, or approximately 43,085 feet in length. That is approximately 6,000 feet less than the amount that was tested in 2000. The reason for the discrepancy in mileage was not apparent, but the additional mileage tested could have been part of the system depicted in a diagram Respondent produced showing 9.06 miles (47,837 feet) of 6-inch pipe, plus an additional 1.7 miles (8,976 feet) of mixed 6- and 4-inch pipe.[23] Based on this evidence, I find the segment was pressure tested and Respondent has maintained the necessary documentation. Accordingly, this alleged violation is withdrawn.

Weeks Island to Olivier (Segment 10)

Respondent contended that the Weeks Island to Olivier pipeline segment was idled in 2010 and remains idled at this time. Respondent further contended that the segment was pressure tested in 2000 and 2005. Respondent submitted pressure test records from 2000 and 2005.[24]

The records submitted by Respondent were not sufficient to demonstrate the pipeline segment had been pressure tested in accordance with Subpart E because no pressure recording charts were included. Without adequate pressure test documentation, I find the pipeline was operated out of compliance with § 195.302. The status of the segment as idled at the time of the OPS inspection does not excuse noncompliance.

BOP to Petrotex Mixed Butylene (Segment 19)

Respondent contended that the BOP to Petrotex Mixed Butylene pipeline segment was idled at some point prior to the OPS inspection and remains idled at this time. Respondent further

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[20] Abandoned pipelines, by comparison, are recognized in the regulations as ones that have been permanently removed from service by safely disconnecting the line from the operating pipeline system, purging of combustibles, and sealing to minimize safety and environmental hazards if left in place.

[21] Post-hearing Submission, Exhibit 6, p 2.

[22] Post-hearing Submission, Exhibit 28.

[23] Post-hearing Submission, Exhibit 27.

[24] Post-hearing Submission, Exhibit 46.

contended that the segment was pressure tested in 1982. Respondent noted that the segment has been renamed BOP to TOP Junction.

The records submitted by Respondent were from a pressure test in 1982 and appear to contain all of the information required by § 195.310, including pressure recording charts and test instrument calibration data. Based on this evidence, I find Respondent has demonstrated the segment was pressure tested. This alleged violation is withdrawn.

BOP to Texas Olefins Raffinate (Segment 23)

Respondent contended that the BOP to Texas Olefins Raffinate pipeline segment was idled in 2003 and remains idled at this time. Respondent further contended that the segment was pressure tested in 1982.

Respondent submitted test records from 1982 for the "BOP - Texas Olefins Spare Liquid Hydrocarbon Line."[25] Some of the same records were also provided for the Texas Olefins Multi-Products Crossover (Segment 22, *see* above).[26]

The test record station identification numbers appear to correlate with the diagram of this pipeline segment and appear to contain all of the information required by § 195.310, including pressure recording charts and test instrument calibration data. Based on the evidence, I find Respondent has demonstrated the pipeline segment was pressure tested. This alleged violation is withdrawn.

c. <u>Segments that Respondent Claimed Were Sold</u>

Means to Ector (Segment 1)

Respondent contended that the Means to Ector pipeline segment was sold in 2004. Respondent also stated that prior to the sale, the segment did not have to comply with the pressure testing requirement in § 195.302 because the segment had been "derated," meaning the maximum operating pressure (MOP) was established under § 195.406(a)(5) based on 80 percent of the highest operating pressure to which the pipeline was subjected (*see* § 195.302(b)(1)).

Respondent submitted a Bill of Sale showing this segment was sold in 2004.[27] Based on this evidence, I find Respondent did not operate this pipeline during the time period relevant to this case, which is five years prior to issuance of the Notice. This alleged violation is withdrawn.

Bullard to Gate Plant "C" (Segment 13)

Respondent contended that the Bullard to Gate Plant "C" pipeline segment was sold in 2000. Respondent also stated that prior to the sale the segment did not have to comply with the

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[25] Post-hearing Submission, Exhibit 93.

[26] Post-hearing Submission, Exhibit 90.

[27] Post-hearing Submission, Exhibit 8.

pressure testing requirement in § 195.302 because Respondent had elected the risk-based alternative to pressure testing under § 195.303 (*see* § 195.302(b)(4)).

Respondent submitted a Purchase and Sale Agreement showing the segment was sold in 2000.[28] Based on this evidence, I find Respondent did not operate this pipeline during the time period relevant to this case. This alleged violation is withdrawn.

d. Segments that Respondent Claimed Were Exempt from § 195.302 Under a Risk-Based Alternative Program[29]

Pierce Junction to Luling (Segment 3)

Respondent contended that the Pierce Junction to Luling pipeline segment did not have to comply with the pressure testing requirement in § 195.302 because Respondent had elected a risk-based alternative to pressure testing covered under § 195.303 (*see* § 195.302(b)(4)). In addition, Respondent contended that the segment was pressure tested in 1961, 1969, and 1992.

As noted above, § 195.303 permitted operators to elect a risk-based program for older pipelines as an alternative to the pressure test deadlines set forth in § 195.302(c)(2). An operator electing this approach in 1998 was required to evaluate each pipeline segment according to a list of risk factors and to assign each pipeline segment a corresponding risk classification.[30] Pressure tests were still required for pipelines constructed of electric resistance-welded (ERW) pipe manufactured prior to 1970 that were susceptible to longitudinal seam failures. Other segments, depending on risk classification, could be evaluated with an inline inspection (ILI). Pipelines in the lowest risk category were not subject to additional measures. Deadlines for testing and inspections under the alternative program were specified in § 195.303(f).

In accordance with § 195.303(d), all pre-1970 ERW pipe was deemed susceptible to longitudinal seam failures unless an engineering analysis showed otherwise. In conducting an engineering analysis, an operator was required to consider among other things: (1) seam-related leak history of the pipe and pipe manufacturing information as available, including the pipe steel's mechanical properties and fracture toughness; (2) the manufacturing process and controls related to seam properties, including whether the ERW process was high-frequency or low-frequency, whether the weld seam was heat treated, whether the seam was inspected, the test pressure and duration during mill hydrotest; (3) the quality control of the steel-making process; and (4) other factors pertinent to seam properties and quality.

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[28] Post-hearing Submission, Exhibit 56.

[29] Respondent contended in its Pre-hearing Submittal that five segments were exempt from § 195.302 because they were covered by § 195.303; however, the evidence produced suggested Respondent intended to make this claim for six segments.

[30] An operator electing to follow an alternative program was required to develop the plans and schedule for testing by December 7, 1998.

According to Respondent's record, the Pierce Junction to Luling pipeline segment was "[c]omposed almost exclusively of pre-1970 ERW pipe."[31] This means it was required to be deemed susceptible to longitudinal seam failures and pressure tested, unless an engineering analysis showed otherwise. Respondent produced an engineering analysis for the segment completed in 1999. The analysis concluded that the segment was not susceptible to seam failures based on an evaluation of leak history, design pressure, and pipe metallurgy. With regard to leak history, the analysis concluded there was no propensity to seam-related failures because only two failures were documented during pressure tests. In one failure, it was noted that "the weld seam provided a weak path along which to grow," but the root cause of the crack was determined to be a gouge. Design pressure and pipe metallurgy were found to be within specification. The analysis did not contain any information about the manufacturing process and controls.

Having reviewed the engineering analysis for the Pierce Junction to Luling segment, I find it did not give adequate consideration to the weakness along the longitudinal seam discovered at one of the failure sites. The weakness of the seam was a significant finding during the evaluation of seam integrity. Even though seam failure was not the root cause of the leak, there was an absence of analysis supporting a conclusion that there was no propensity for seam-related failure despite the weakness of the seam. In addition, there was no information regarding the manufacturing process and controls of the pipe. In accordance with the regulatory presumption that all pre-1970 ERW pipelines are susceptible to seam failure unless otherwise shown, these factors should have weighed in favor of a conservative conclusion regarding susceptibility. I find the engineering analysis did not have sufficient support for concluding the pre-1970 ERW segment was not susceptible to longitudinal seam failure.

Under § 195.303, all pre-1970 ERW pipeline segments susceptible to seam failure covered by a risk-based alternative program were required to be pressure tested unless the analysis showed otherwise, which in this case it did not. Respondent contended that even though it believed a pressure test was not required, the Pierce Junction to Luling segment was pressure tested in 1961, 1969, and 1992. Respondent submitted certain pressure test records from 1961 and 1992.[32]

The records submitted by Respondent were not sufficient to demonstrate the entire pipeline segment had been pressure tested. The records from 1961 did not include pressure recording charts and the records from 1992 did not document a pressure test on the entire 140.9-mile segment. Without adequate pressure test documentation or an acceptable analysis showing a pressure test was not required, I find the pipeline was operated out of compliance.

SMI 6A to South Bend (Segment 5)

Respondent contended that this pipeline segment did not have to comply with the pressure testing requirement in § 195.302 because Respondent had elected the risk-based alternative to

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[31] Post-hearing Submission, Exhibit 12.

[32] Post-hearing Submission, Exhibits 14-16.

pressure testing covered under § 195.303. Respondent did not contend the SMI 6A to South Bend segment was ever pressure tested.[33]

The SMI 6A to South Bend pipeline segment was "[c]omposed almost exclusively of pre-1970 ERW pipe."[34] Respondent produced an engineering analysis completed in 1998, which concluded that the pre-1970 ERW pipe was not susceptible to seam failures. This conclusion was based on an evaluation of leak history, design pressure, pipe manufacturing, and pipe metallurgy. With regard to leak history, the analysis noted two leaks on the body of the pipe caused by outside force damage and no history of seam-related leaks. The vintage, manufacturer, and pipe mill were all considered. No manufacturing records were located from the mill, but the pipe specification license of the mill was considered. The license would have required the mill to perform pressure tests and nondestructive inspection of all ERW welded seams along with visual inspections.

Analysis of the metallurgy noted that the pipe was manufactured using high-frequency ERW welding, but the analysis found there had been no normalization by post-weld heat treatment, which had caused "higher-than-normal microhardness tests." As a result, the analysis found inadequate toughness tests and inadequate shear requirement. There is no further analysis of whether or to what extent those qualities could impact the susceptibility of the seam to failure. In addition, even though the mill's pipe specification license was considered, there was an absence of manufacturing records for the segment to determine if these processes were actually followed. Under the presumption that all pre-1970 ERW pipelines are susceptible to seam failure unless otherwise shown, these issues should have weighed in favor of a conservative conclusion regarding susceptibility absent further analysis.

Accordingly, I find the engineering analysis did not have sufficient support for concluding that the SMI 6A to South Bend segment was not susceptible to longitudinal seam failure. For the above reasons, I find the pipeline was operated out of compliance.

New Iberia to Sunset (Segment 7)

Respondent contended that this pipeline segment did not have to comply with the pressure testing requirement in § 195.302 because Respondent had elected a risk-based alternative to pressure testing under § 195.303. In addition, Respondent contended that the segment was pressure tested in 1971-1973, and again in 2011 after the OPS inspection. Respondent explained that the segment has now been purged of product and idled.

The documentation submitted by Respondent consisted of MOP inventory data sheets and emails concerning a prospective tool run.[35] These records do not demonstrate that Respondent had evaluated the segment according to the risk factors in § 195.303 or that Respondent had assigned a risk classification that exempted the segment from pressure testing.

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[33] Post-hearing Submission, Exhibit 6.

[34] Post-hearing Submission, Exhibit 22.

[35] Post-hearing Submission, Exhibits 32-35.

No additional documentation was submitted to demonstrate the segment had been pressure tested prior to the OPS inspection. Accordingly, I find this segment was not in compliance.

South Bend to New Iberia (Segment 8)

Respondent contended that this pipeline segment did not have to comply with the pressure testing requirement in § 195.302 because Respondent had elected the risk-based alternative to pressure testing. In addition, Respondent contended that the segment was pressure tested in 1972 and again in 2011 after the OPS inspection. Respondent noted that a portion of the segment is currently idled.

The documentation submitted by Respondent consisted of MOP inventory data sheets.[36] These records do not demonstrate that Respondent had evaluated the segment according to the risk factors in § 195.303 or that Respondent assigned a risk classification that exempted the segment from pressure testing.

Respondent did not submit any additional documentation to show the segment had been pressure tested prior to the OPS inspection. Accordingly, I find this segment was not in compliance.

Sunset to Anchorage (Segment 9)

Respondent contended that this pipeline segment did not have to comply with the pressure testing requirement in § 195.302 because Respondent had elected the risk-based alternative to pressure testing under § 195.303. In addition, Respondent contended that the segment was pressure tested in 1971 and 1998. Respondent noted that the segment is currently idled.

The documentation submitted by Respondent consisted of MOP inventory data sheets and emails concerning a prospective tool run.[37] The records do not demonstrate Respondent had evaluated the segment pursuant to § 195.303 or assigned a risk classification that exempted the segment from pressure testing. In addition, Respondent did not submit documentation to show the pipeline segment had been pressure tested prior to the OPS inspection. Accordingly, I find this segment was not in compliance.

Borregas to Viola (Segment 20)

Respondent contended that this pipeline segment did not have to comply with the pressure testing requirement because Respondent had elected the risk-based alternative to pressure testing. In addition, Respondent contended that the segment was pressure tested in 2006.

Respondent did not submit any documentation to suggest Respondent had evaluated the segment pursuant to a risk-based program that complied with § 195.303. In addition, the pressure test

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[36] Post-hearing Submission, Exhibits 36-39.

[37] Post-hearing Submission, Exhibits 40-44.

records submitted were missing necessary data, such as test pressure, duration, and temperature.[38] Accordingly, I find this segment was not in compliance.

e. Segments that Respondent Claimed Were Exempt from Part 195

Sarita to Borregas (Segment 17)

Respondent contended that the Sarita to Borregas pipeline segment is an unregulated gathering line exempt from Part 195 (*see* § 195.1).

Respondent submitted supporting documentation to prove this segment is an unregulated gathering line. Accordingly, this alleged violation is withdrawn.

SMI 6B to 6A (Segment 18)

Respondent contended that this pipeline segment was exempt from Part 195 because it was an offshore pipeline located upstream of a production facility (*see* § 195.1(b)(5)). In addition, Respondent noted that this segment was abandoned in 2007.

Respondent submitted supporting documentation to prove this segment was an offshore pipeline upstream of a production facility, which is not subject to the requirements in § 195.302. Accordingly, this alleged violation is withdrawn.

Texaco 11C to SMI 6B (Segment 26)

Respondent contended that this pipeline segment was exempt from Part 195 because it was an offshore pipeline located upstream of a production facility. In addition, Respondent noted that this segment was abandoned in 2007.

Respondent submitted supporting documentation to prove this segment was an offshore pipeline upstream of a production facility, which is not subject to the requirements in § 195.302. Accordingly, this alleged violation is withdrawn.

f. Additional Segment for Which Respondent Provided Records

Hawkins to MidValley Junction

This pipeline segment was not listed in the Spreadsheet, but Respondent introduced records for the segment and contended that pressure testing was not required because the segment had been "derated," meaning MOP had been established under § 195.406(a)(5) based on 80 percent of the highest operating pressure to which the pipeline was subjected (*see* § 195.302(b)(1)).

Since the Notice did not allege a violation with respect to this segment, no finding is made as to whether the segment was in compliance at the time of the OPS inspection.

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[38] Post-hearing Submission, Exhibits 82 and 83.

Conclusion

In summary, having reviewed the evidence in the record, I find Respondent violated § 195.302 by operating 19 pipeline segments identified above as Segments 2–5, 7–12, 14–16, 20–22, 24, 25 and 27, which had not been pressure tested as set forth in the regulation.

For the reasons stated above, I withdraw the allegations that Respondent violated § 195.302 with regard to 8 pipeline segments identified above as Segments 1, 6, 13, 17–19, 23 and 26.

Item 2: The Notice alleged that 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 failed on two occasions to timely discover conditions on its pipelines following an integrity assessment. In the first instance, the Notice alleged that Respondent failed to discover conditions promptly, but no later than 180 days after an integrity assessment on its LA-16A and 16B 20”/22” Melville to Boyce crude oil pipeline. In the second instance, the Notice alleged that Respondent failed to timely discover conditions on its West Delta 73 to Grand Isle Station offshore pipeline.

a. Melville to Boyce pipeline

With regard to the Melville to Boyce crude oil pipeline, the Notice alleged that Respondent completed an integrity assessment of the pipeline on October 25, 2007, making the deadline April 22, 2008 for obtaining adequate information and discovering conditions under § 195.452(h)(2). The Notice alleged that Respondent extended its own internal deadline for discovering conditions twice, first to June 21, 2008, and then again to September 30, 2008, due to the tool vendor taking 159 days to provide the preliminary report. The extensions were allegedly to allow Respondent additional time for data integration, information analysis, receipt of the final report, and development of a repair plan. The Notice alleged these reasons did not justify failure to comply with the 180-day deadline or render the regulatory deadline "impracticable." Thus, the Notice alleged Respondent violated the regulation by failing to discover conditions by April 22, 2008.

In its written submissions and at the hearing, Respondent argued that it was impracticable to discover conditions within 180 days of the integrity assessment because adequate information was not available. Since the preliminary inline inspection (ILI) data was received from the vendor less than 22 days before the 180-day deadline, Respondent argued that it needed additional time to perform the comprehensive data integration and analysis required by its procedures and the regulation. It was not until the data integration and analysis were complete that Respondent contended it had adequate information about the pipeline.

Respondent explained that its integrity management program (IMP) "requires the integration of all available information about the integrity of the entire pipeline in conducting an integrity assessment and evaluation prior to declaring final discovery of a condition."[39] This includes comprehensive data integration and analysis, including analysis of the ILI results and overlay of the data with additional information, such as cathodic protection, pressure testing, previous ILIs, depth of cover, waterway crossings, aerial patrols, leak history, and previous repairs.

Respondent stated that it was necessary to extend the discovery period by an initial 60 days to permit validation digs, receive the final report, analyze the results, complete data integration and develop a repair plan. Respondent then extended the period by an additional 60 days because it "needed additional ILI data and examination in order to perform the analysis required" for the remaining repairs that were identified. Respondent attributed these delays to the vendor and the "extensive" amount of information that needed to be integrated, noting there was "significant delay required by the vendor to integrate and overlay all of the integrity information for this pipeline segment."[40]

Respondent further contended that its procedures were consistent with the requirements in § 195.452(g), PHMSA guidance at FAQs 7.19 and 4.13, a prior enforcement case, and a recommendation by the National Transportation Safety Board (NTSB).

After the hearing, Respondent submitted additional documentation, including emails between EMPCo and the ILI vendor regarding the status of the ILI results and the delays.

Applicable safety standards

Pursuant to § 195.452(j)(3), pipeline operators must regularly assess their line pipe at specified intervals.[41] Following an integrity assessment, an operator must promptly, but within 180 days, obtain sufficient information to determine whether conditions on the pipeline present a potential threat to integrity, unless the 180-day period is impracticable.[42] Operators must address all

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[39] Closing, p.3.

[40] EMPCo letter dated August 30, 2012, p.4 (Closing).

[41] § 195.452(j).

[42] § 195.452(h)(2).

anomalous conditions discovered through the integrity assessment according to a schedule set forth in the regulation.[43]

In addition to performing integrity assessments, operators must also periodically evaluate the integrity of each pipeline by analyzing "all available information about the integrity of the entire pipeline and the consequences of a failure."[44] Information required to be analyzed pursuant to § 195.452(j)(2) includes, among other things, data gathered though integrity assessments, other inspections and tests (such as corrosion control monitoring), and preventative and mitigative actions. The periodic evaluation must be conducted "as frequently as needed,"[45] and operators must remediate any integrity issues raised by the information analysis that could reduce a pipeline's integrity.[46]

Findings

The extent to which an operator is required to perform comprehensive data integration under § 195.452(g) and (j)(2) *before* discovering conditions under § 195.452(h)(2) was central to Respondent's position. Contrary to Respondent's assertions, however, I find § 195.452(h)(2) does not explicitly require comprehensive data integration; rather it requires that sufficient information be obtained to determine whether conditions on the pipeline present a potential integrity threat. If an operator obtains information following a tool run showing conditions that could present a potential integrity threat, the operator is capable of discovering those conditions for purposes of § 195.452(h)(2) without the need to perform an evaluation under § 195.452(j)(2).[47]

In this case, Respondent had chosen to evaluate all available information about the integrity of the entire pipeline following each integrity assessment. That is permissible so long as Respondent complies with § 195.452(h)(2) by ensuring that it discovers conditions promptly, but within 180 days after the integrity assessment. Respondent may not delay discovery beyond the 180-day deadline just to complete data integration, if it already has information that conditions could present a potential integrity threat.

I agree with Respondent that in some situations, a delay in receiving ILI results from a tool vendor may render the 180-day discovery period impracticable. If the 180-day period is justifiably exceeded, as it may have been here, an operator must still take action to ensure that discovery is completed as soon as practicable to comply with § 195.452(h)(2).

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[43] § 195.452(h)(1), (h)(3).

[44] § 195.452(g) and (j)(2).

[45] § 195.452(j)(2).

[46] § 195.452(h).

[47] Certain data integration, such as overlaying multiple tool runs, may be necessary to discover certain types of conditions (e.g., dents with metal loss). To ensure compliance with § 195.452(h)(2), PHMSA expects multiple tool runs to be completed in close proximity (*see* FAQ 6.6), but the 180-day discovery period for each run still begins when that specific tool reaches the receiver (*see* FAQ 4.13). The need to overlay data from a second or third tool run does not render it "impracticable" to discover conditions from the first run (so long as there is adequate information that conditions present a potential threat to integrity).

Accordingly, I evaluate the evidence to decide whether Respondent discovered conditions as soon as practicable following receipt of the ILI vendor report. The evidence shows that Respondent received the preliminary ILI report on March 31, 2008, 159 days after the integrity assessment. Respondent expected the final report on April 15, 2008, 174 days after the integrity assessment, but extended the discovery deadline by 60 days to provide time for receiving the final report, analyzing the results, completing data integration including consideration of tool tolerances, analyzing risks and threats, and developing a repair plan.[48] Then, after a repair plan had been completed, Respondent extended the discovery deadline by 60 days for a second time to request that the ILI vendor perform additional calculations to more accurately assess the number of required repairs and to produce an overlay report with several historical tool runs to get a more comprehensive view of the pipeline's integrity.[49]

Having considered the evidence, I find Respondent has not demonstrated it was necessary to exceed the 180-day discovery period by 120 days. It would have been practicable for Respondent to discover conditions prior to the second 60-day extension, when it had already validated the ILI data, analyzed the results, considered tool tolerances, and developed a repair plan. Accordingly, I find even though it may have been impracticable for Respondent to discover conditions within 180 days of the integrity assessment, Respondent failed to discover conditions as soon as practicable thereafter.

Guidance and prior enforcement

With regard to Respondent's contention that its procedures were consistent with PHMSA guidance and prior enforcement, I find the extent to which the procedures were consistent does not impact the finding that Respondent failed to discover conditions as soon as practicable.

For example, Respondent cited FAQ 7.19 regarding the consideration of tool tolerances for determining if a detected anomaly meets the repair criteria in §195.452(h)(4).[50] The guidance states that operators must integrate relevant information about the condition of the pipeline in making decisions on excavation timing and other mitigative actions.

Respondent appropriately recognized the need to integrate relevant information about tool tolerances. As noted above, Respondent had already considered tool tolerances and developed a repair plan when it extended discovery for a second time. While Respondent may have considered tool tolerances as set forth in the guidance, it did not discover conditions as soon as practicable in accordance with § 195.452(h)(2).

Similarly, guidance at FAQ 4.13 defines the completion of an integrity assessment for the purpose of calculating the 180-day discovery period. The guidance states that when an ILI tool

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[48] Violation Report, Exhibit 2-2.

[49] Violation Report, Exhibit 2-4.

[50] PHMSA publishes answers to FAQs concerning compliance with the integrity management regulations at: http://primis.phmsa.dot.gov/iim. These guidance materials do not constitute rules themselves but provide informal information about how to implement integrity management programs in accordance with applicable requirements.

reaches the receiver, that is the date the assessment is considered complete, which in turn starts the discovery period.

Since there is no question that the assessment in this case was completed on October 25, 2007, making the original deadline for discovery April 22, 2008, I find this guidance does not impact the finding that Respondent failed to discover conditions as soon as practicable.

In the prior enforcement case cited by Respondent, PHMSA found an operator had violated § 195.452(j) by failing to perform a periodic evaluation that integrated results from prior corrosion and cracking integrity assessments.[51] In the present case, OPS has not alleged that Respondent violated § 195.452(j) by failing to perform data integration. Rather, the evidence demonstrates Respondent failed to discover conditions promptly after an integrity assessment under § 195.452(h)(2). Respondent may not delay discovery beyond the 180-day deadline just to complete its data integration process if it already has sufficient information that conditions could present a potential integrity threat.

Finally, Respondent argued that it kept in communication with PHMSA regarding the delay, which is consistent with a recommendation issued by the NTSB to require greater operator communication when discovery is delayed.[52] Respondent's communication with PHMSA is noted, but does not preclude finding that discovery was not made in accordance with § 195.452(h)(2).

For the above reasons, I find Respondent violated § 195.452(h)(2) by failing to discover conditions on its LA-16A and 16B 20"/22" Melville to Boyce crude oil pipeline as soon as practicable following receipt of the ILI data from the tool vendor.

b. West Delta 73 to Grand Isle Station pipeline

The Notice also alleged that Respondent failed to discover conditions promptly after an integrity assessment on its West Delta 73 to Grand Isle Station offshore pipeline. Specifically, the Notice alleged that Respondent completed an integrity assessment on February 2, 2010, making the 180-day discovery deadline August 1, 2010. Respondent received a preliminary report from the tool vendor on March 12, 2010. Respondent then invalidated the tool run and completed a subsequent integrity assessment on May 31, 2010, receiving the preliminary report from that run on November 26, 2010.

At the hearing, OPS alleged that Respondent had invalidated the February 2010 tool run data based on "unity charts," which are described in its IMP procedures at Section 4. OPS alleged that Respondent believed the unity charts demonstrated problems with the tool data. Based on its own review of the unity charts, however, OPS believed the charts showed the ILI data was within an acceptable range. For this reason, OPS alleged Respondent's rationale for invalidating

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[51] *See Enbridge Energy, LP*, Final Order, CPF No. 3-2012-5013, Item 4, 2012 WL 5473686 (Sept. 7, 2012) (enforcement cases are also available online at http://www.phmsa.dot.gov/pipeline/enforcement).

[52] *See* NTSB Accident Report PAR-12/01, *Enbridge Inc., Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010* (adopted Jul. 10, 2012) (http://www.ntsb.gov/doclib/reports/2012/par1201.pdf).

the February 2010 integrity assessment was not justified, and the operator violated § 195.452(h)(2) by failing to discover conditions on the line by August 1, 2010.

In its written submissions and at the hearing, Respondent contended that it followed its procedures and the applicable regulations when it evaluated the quality of the data from the February 2010 tool run. Respondent explained that the tool in question failed to pass Respondent's validation process on two separate occasions because it was not accurately sizing the type of anomalies indicated by the preliminary results. In other words, the data was potentially under-reporting anomalies on the line.

The validation process is set forth in Respondent's procedures at Section 2.0 of Appendix K of its IMP. The procedures require the use of "control charts" to validate tool run data. Control charts are a "statistical tool used to analyze the tool vs. field data."[53] Upon receiving preliminary data from an ILI run, the operator selects five to ten anomalies to excavate and measure. Tool data and field readings are then plotted on the control chart. If the number of points falling outside of the established boundaries for normal data exceeds a certain level, the test fails, which "is strong statistical evidence that the magnitude of error is unusual, and it may be necessary to reject the run."

The unity charts referenced in the Notice, Respondent explained, are not used for the purpose of validating ILI tool data. They are used after the data passes the control charts to adjust the repair plan as information gathered from 20 to 30 excavations suggests the data is more or less accurate than originally believed.

Even though Respondent was concerned with the validity of the February 2010 data, it implemented mitigative steps to address the potential corrosion issues indicated by the data, including enhanced air and helicopter patrols, aggressive maintenance pigging, and increased biocide and corrosion mitigation treatments. Respondent also notified PHMSA of the issue it was having with the ILI data. Respondent scheduled two additional ILI tool runs on the pipeline: a different magnetic flux leakage tool and a more advanced ultrasonic thickness tool. The tool runs were completed on May 31, 2010. Data from the ultrasonic tool was successfully validated using the control charts and Respondent stated that it completed discovery within 180 days of the successful tool run.

Following the hearing, Respondent provided additional documentation to substantiate its validation process and its decision concerning the failed tool run. Respondent submitted documents comparing its validation of the failed tool run with a validation of a successful tool run, as well as internal correspondence and correspondence with the tool vendor.

Findings

Section 195.452(h)(2) requires an operator to obtain sufficient information about conditions on its pipelines "promptly, but no later than 180 days after an integrity assessment." While it is usually evident when an integrity assessment is completed (e.g., at the conclusion of a pressure

[53] *See* Pre-Hearing Submittal, Exhibit (Tab) 18.

test or ILI tool run), PHMSA has issued guidance to assist operators in applying the regulation in less common situations.[54] Among other things, FAQ 4.13 provides that if ILI tool run data is determined to be "suspect and an entire rerun is to be performed, then the evaluation will be expected within 180 days after the successful rerun."[55]

Respondent has presented documentation to show that the data from the February 2010 tool run was suspect. Respondent reached this conclusion by following its procedures in Appendix K of its IMP manual to determine the validity of the data. The data failed the validation procedures two separate times.[56] In the first instance, too many points on the control chart were more than one standard deviation from the mean. In the second instance, too many points were on the same side of the mean. Since the tool run data was suspect and Respondent decided to perform a rerun, the discovery period ended 180 days after the successful rerun in May 2010.

Accordingly, I find Respondent did not violate § 195.452(h)(2) with respect to the February 2010 tool run on its West Delta 73 to Grand Isle Station pipeline. This alleged violation is withdrawn.

Conclusion

In summary, having reviewed the evidence in the record, I find Respondent violated § 195.452(h)(2) by failing to discover conditions on its Melville to Boyce pipeline as soon as practicable following receipt of ILI data. I further find the alleged violation with regard to the West Delta 73 to Grand Isle Station pipeline must be withdrawn.

Item 3: The Notice alleged that Respondent violated 49 C.F.R. § 195.452(h)(4), 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 . . . .
> (i) *Temporary pressure reduction.* An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure.
> (ii) Long-term pressure reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

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[54] *See* FAQ 4.13.

[55] FAQ 4.13.

[56] *See* Pre-hearing Submittal, Exhibits 24 and 27.

> (3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.
>
> (4) *Special requirements for scheduling remediation.*—(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in Section 451.6.2.2(b) of ANSI/ASME B31.4 (incorporated by reference, *see* § 195.3). An operator must treat the following conditions as immediate repair conditions:
>
> (A) Metal loss greater than 80% of nominal wall regardless of dimensions . . . .
>
> (D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

The Notice alleged that Respondent failed on three occasions to address immediate repair conditions in accordance with the operator's schedule for remediation. The Notice also alleged that Respondent failed to temporarily reduce operating pressure or shut down two pipelines until the repairs were completed. Two of the three conditions were on the West Delta 73 offshore pipeline and the third was on the South Marsh Island (SMI) 69B offshore pipeline.

a. West Delta 73 pipeline

The Notice alleged that Respondent repaired two West Delta 73 immediate repair conditions more than eight months after receiving a preliminary integrity assessment report and over four months after receiving a second report, even though Respondent's procedures required immediate repairs to be confirmed and repaired within five business days. The Notice further alleged that Respondent did not reduce operating pressure on the West Delta 73 pipeline because the operator concluded there were low operational risk levels.

In its Response, EMPCo explained that the pipeline is located offshore, which requires considerably more time to permit, plan, stage and execute repairs; therefore, it was not practicable for Respondent to complete the repairs within five days as set forth in its IMP. Respondent noted that PHMSA guidance on this issue states that immediate repairs should be made "as soon as practicable."[57] Respondent also explained that the lines were already operated at low pressures and the corrosion defect anomalies detected were rated as not needing further pressure reduction under the applicable calculations. In accordance with its IMP and the relevant requirements, Respondent stated that it filed a timely safety related condition report to notify PHMSA that the repairs were being evaluated and scheduled, and that additional pressure

[57] FAQ 7.4.

restrictions would not be necessary. Respondent submitted relevant documentation including evaluations, calculations, work procedures, and notifications.

Applicable safety standards

The integrity management standards in § 195.452 apply to each hazardous liquid pipeline that could affect a high consequence area (HCA). Section 195.452(h) requires operators to take prompt action to address anomalous conditions discovered through a pipeline integrity assessment.[58] Each operator must remediate conditions according to a schedule that includes provisions for "immediate repair conditions."[59] Examples of immediate repair conditions are areas of corrosion with greater than 80% wall loss, or dents located on the top of the pipe with a depth greater than 6% of the pipe diameter.[60] Upon discovering an immediate repair condition, an operator must temporarily reduce operating pressure or shut down the pipeline until the repair is completed.[61] The pressure reduction must be calculated using the formula in Section 451.6.2.2(b) of consensus standard ASME B31.4-2006, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (incorporated by reference, *see* § 195.3).[62] If an operator cannot meet its schedule for repair and cannot provide safety through a temporary reduction in operating pressure, the operator must notify PHMSA.[63]

The formula for calculating a pressure reduction in Section 451.6.2.2(b) of ASME B31.4-2006 refers to a secondary source, ASME B31G-2004, *Manual for Determining the Remaining Strength of Corroded Pipelines* (incorporated by reference, *see* § 195.3) for calculating safe operating pressure. The calculation is based on measurements of the longitudinal extent and maximum depth of the corroded areas, the outside diameter of the pipe, and wall thickness. In some situations, if the measured severity of the corroded area results in a safe maximum pressure for the corroded area that is higher than the maximum operating pressure (MOP) of the pipeline, the standards indicate the corroded region may be used for service without further reduction to the MOP.[64]

PHMSA has issued guidance that operators must still reduce operating pressure even if the calculated pressure is greater than the existing operating pressure, stating that in this "rare" situation operators "should determine the amount of such reduction based on their particular circumstances."[65] PHMSA also stated that a "reduction of 20 percent below the highest operating pressure actually experienced . . . may provide the necessary additional safety margin."[66] While

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[58] §195.452(h)(1).

[59] § 195.452(h)(3) and (h)(4)(i).

[60] § 195.452(h)(4)(i)(A) and (h)(4)(i)(B).

[61] § 195.452(h)(4)(i).

[62] § 195.452(h)(4)(i).

[63] § 195.452(h)(1)(i) and (h)(3).

[64] *See, e.g.*, ASME B31G (2004), sections 1.5 and 4.3; ASME B31.4 (2006), sections 451.6.1(e)(3) and 451.6.2.2(b).

[65] FAQ 7.22.

[66] FAQ 7.20.

this guidance provides informal information about how to implement integrity management programs, the guidance does not constitute a rule itself and therefore may not mandate a pressure reduction where it is not otherwise required by the applicable regulations and standards incorporated by reference.[67]

Respondent's procedures

The relevant procedures from Respondent's IMP are included in the record.[68] In particular, *Figure 2.5: Discovery and SRC Review/Determination Process*, dated September 30, 2010, states that upon receiving a final or preliminary inline inspection report that identifies potential immediate repair conditions, Respondent must follow the requirements in § 195.452(h)(4)(i) to calculate a potential pressure reduction. If a pressure reduction is necessary under the formula, Respondent must initiate the temporary reduction. Whether or not a reduction is necessary, Respondent must also determine if the repair can be completed in five days. If the repair can be completed in five days, Respondent must take action to complete the repair. If the repair cannot be completed in five days, Respondent must report the condition to PHMSA.

Findings

On March 15, 2010, Respondent discovered that two locations on its West Delta 73 offshore pipeline had indications of internal corrosion with wall loss potentially greater than 80%. These anomalies met the definition of an immediate repair condition. Respondent performed a calculation pursuant to § 195.452(h)(4)(i) and determined that no further pressure reduction was necessary on the line due to the pipeline already operating at a low stress level of 21% of the minimum yield strength and no susceptibility to a rupture type failure. In addition, Respondent had determined that if it reduced operating pressure any further, it would have impaired the ongoing corrosion mitigation treatments, which included injection of biocides and aggressive cleaning pigs. Respondent also determined that it would not be possible to repair the conditions within five days due to the location of the pipeline offshore at depths up to 50 feet and the difficulty securing offshore pipeline repair resources as a result of Deepwater Horizon oil spill and cleanup efforts. Accordingly, Respondent submitted a notification to PHMSA dated March 26, 2010.[69]

Both § 195.452(h)(1)(i) and Respondent's procedures recognized that it may not always be possible for the operator to complete a repair of an anomalous condition according to the predetermined schedule set forth in the operator's IMP.[70] When this occurs, § 195.452(h)(3) and

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[67] In 2007, PHMSA attempted to amend § 195.452(h)(4) to provide flexibility in the methods an operator may use to calculate a pressure reduction "if the formula [in ASME/ANSI B31.4] results in a calculated pressure higher than the original operating pressure." *See* Integrity Management Program Modifications and Clarifications, 72 Fed. Reg. 39012, 39015 (Jul. 17, 2007). The amendment was never incorporated into the code due to a technicality in the amendatory instructions. § 195.452 "Editorial Note" (2007). PHMSA currently has another rulemaking proposing to amend § 195.452(h)(4) for this purpose. *See* Miscellaneous Changes to Pipeline Safety Regulations, 76 Fed. Reg. 73570, 73581 (proposed Nov. 29, 2011).

[68] *See* Violation Report, Exhibit 3-1.

[69] Violation Report, Exhibit 3-2.

[70] *See* FAQ 7.4 (stating that an immediate repair condition must be repaired "as soon as practicable").

Respondent's procedures required the operator to notify PHMSA. Based on the evidence in the record, Respondent filed a timely safety related condition report in accordance with these requirements and notified PHMSA that the offshore repair was not practicable within five days. Respondent completed the repairs as soon as was practicable.

Section 195.452(h)(4)(i) also required Respondent to temporarily reduce operating pressure, but the formula for calculating the pressure reduction recognized that when operating pressure is already low, a corroded region may sometimes be used for service without further reduction. In most cases, PHMSA still expects operators to reduce operating pressure to ensure an additional margin of safety. In the present case, however, Respondent has demonstrated there was sufficient justification for its decision to rely on the formula in Section 451.6.2.2(b) of ASME B31.4. Specifically, the operator's effort to control internal corrosion justified its decision not to further reduce operating pressure beyond the already low pressure so that it could continue to use corrosion inhibiting treatments.

Accordingly, I find Respondent was in compliance with its own procedures and with § 195.452(h)(4) when it notified PHMSA that repair of the two offshore conditions within five days was not practicable, and when Respondent determined, based on a calculation pursuant to § 195.452(h)(4)(i), that further pressure reduction would be contrary to pipeline safety due to the minimum flow required for internal corrosion mitigation treatments. For these reasons, I find the alleged violation regarding the West Delta 73 pipeline should be withdrawn.

b. SMI 69B pipeline

With regard to the third immediate repair condition, which was on the SMI 69B offshore pipeline, the Notice alleged that Respondent repaired the condition more than two months after receiving the preliminary report. The Notice further alleged that Respondent did not reduce operating pressure because the pipeline operated at less than 40% of the minimum yield strength.

In response to this allegation, Respondent contended that § 195.452 did not apply to the condition because it was located on a pipeline segment that could not affect an HCA. Respondent stated that it nevertheless repaired the condition as soon as practicable and filed a safety related condition report merely "as [a] precautionary measure and to keep PHMSA informed."[71]

Findings

On December 8, 2010, Respondent discovered an anomalous condition on its SMI 69B offshore pipeline that appeared to be a dent located on the top of the pipe with a depth greater than 6% of the pipe diameter. Respondent recognized that the pipeline segment could not affect an HCA, but performed a calculation pursuant to § 195.452(h)(4)(i) and determined that no further pressure reduction was necessary due to the pipeline already operating at a low stress level. Respondent also determined that it would not be possible to repair the condition within five days due to the pipeline being located offshore at a depth of about 120 feet. Respondent submitted a

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[71] Response, p.5.

notification to PHMSA on December 21, 2010. In the notification, Respondent stated that the "repair condition is not located within the boundaries of an HCA."[72] At the hearing and in its written submissions, Respondent confirmed that the repair condition was not located on a pipeline segment that could affect an HCA.

By its terms, the integrity management regulations in § 195.452 apply to pipelines "that could affect a high consequence area." Respondent has demonstrated the anomalous condition on its SMI 69B pipeline was not on a segment that could affect an HCA. Accordingly, this alleged violation must be withdrawn.

Conclusion

In summary, having reviewed the evidence in the record, I withdraw the alleged violations of § 195.452(h)(4).

The findings of violation in this Final Order will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to an administrative civil penalty not to 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.[73]

In determining the amount of a civil penalty under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, I 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; any effect that the penalty may have on Respondent's ability to continue doing business; and the good faith of Respondent in attempting to comply with the pipeline safety regulations. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require.

The Notice proposed a total civil penalty of $151,100 for the three violations cited above.

Item 1: The Notice proposed a civil penalty of $109,500 for Respondent's violation of 49 C.F.R. § 195.302. Respondent violated § 195.302 by operating 19 pipeline segments totaling 529.25 miles of pipe for years without a documented pressure test.

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[72] Pre-hearing Submission, Exhibit 36, p.2.

[73] The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. No. 112-90, § 2(a), 125 Stat. 1905 (Jan. 3, 2012), increased the maximum administrative civil penalty for a pipeline safety violation to $200,000 per violation for each day, up to a maximum of $2,000,000 for a related series of violations.

Pressure tests are important for pipeline safety because they ensure a margin of safety above a pipeline's maximum operating pressure. This safety margin is essential to the prevention of accidents caused by hidden physical defects, such as those from the manufacturing or construction process, or from external forces. When properly performed, pressure tests will disclose physical defects that are large enough to cause the pipe to fail during operation and will provide a proven margin of safety against failure during operation from the growth of defects.

Respondent's operation of untested or inadequately tested pipelines constituted a safety threat and may have exposed persons and property to a heightened risk of an accident caused by unknown pipeline defects. Therefore, I find the nature, circumstances, and gravity of the violation justify a penalty with respect to the 19 pipeline segments.

Respondent is culpable for the violations. I find nothing in the record to warrant adjustment of the penalty for reasons of history of prior offenses or good faith in attempting to achieve compliance.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a reduced civil penalty of $102,300 for the 19 instances of violating § 195.302. This penalty reflects a reduction of $7,200 to account for the eight instances of alleged violation that were withdrawn.[74]

Item 2: The Notice proposed a civil penalty of $20,800 for Respondent's violation of 49 C.F.R. § 195.452(h)(2). Respondent discovered conditions on the Melville to Boyce crude oil pipeline 120 days after the deadline in the regulation. The delay in discovering conditions was a result of Respondent performing a comprehensive data integration of all available information about the integrity of the entire pipeline after having received ILI data from the tool vendor only 22 days before the deadline.

Timely discovery of conditions on a pipeline following an assessment is one of the cornerstones of integrity management. Prompt discovery of conditions ensures that operators will remediate the conditions in accordance with the schedule for repairs set forth in the regulation. Delays to the discovery of conditions can present a potential risk to pipeline safety by delaying repairs.

Having considered the penalty assessment factors, I find several warrant reducing the proposed penalty for this violation. First, I find the delay of the tool vendor in providing ILI data reduces Respondent's culpability for the violation. Although Respondent is ultimately responsible for compliance with the regulation, EMPCo provided documented communications with the tool vendor that demonstrate the operator was cognizant of the regulatory requirement and was taking steps to address the delay.

Second, I find Respondent made a good faith attempt to comply with the regulation by following its procedures for data integration to ensure conditions will be considered and addressed and by

[74] When a civil penalty is assessed for more than one instance of a violation (e.g., 27 instances of failing to perform pressure tests), the additional instances typically elevate the total penalty by less than the amount that is assessed for the first instance.

keeping in communication with PHMSA regarding the delay. Finally, I have withdrawn the alleged violation concerning the West Delta 73 to Grand Isle Station pipeline.

Accordingly, having reviewed the record and considered the assessment criteria I assess Respondent a reduced civil penalty of $10,000.

Item 3: The Notice proposed a civil penalty of $20,800 for Respondent's violation of 49 C.F.R. § 195.452(h)(4). Since this Item has been withdrawn, the proposed penalty is not assessed.

In summary, having reviewed the record and considered the assessment criteria for each of the Items cited above, I assess Respondent a total civil penalty of **$112,300**. This penalty will not affect Respondent's ability to continue doing business.

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 (AMZ-341), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 269039, Oklahoma City, Oklahoma 73125. The Financial Operations Division telephone number is (405) 954-8893.

Failure to pay the $112,300 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. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a district court of the United States.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to the three violations cited above. 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 with the applicable safety standards established under chapter 601.

In its Pre-hearing Submittal, Respondent requested that the proposed compliance terms associated with **Item 1** be withdrawn because its IMP manual already requires a pressure test to be performed if certain lines are reactivated and returned to service.

The terms of the compliance order outlined below are broader than merely testing idled pipelines before returning them to service. Accordingly, the compliance terms are not withdrawn. Respondent may, however, submit its procedures for reactivating idled pipelines to comply with that portion of the compliance order.

In its Pre-hearing Submittal, Respondent contended that it has already complied with the proposed compliance terms associated with **Item 2**. Respondent submitted "proposed draft revisions to its IMP Manual" to demonstrate compliance.[75] The submission of draft procedures, however, are not sufficient to satisfy the compliance order because they do not demonstrate Respondent has adopted the procedures that were submitted.

Since **Item 3** has been withdrawn, the proposed compliance terms in the Notice that were associated with that Item are not included in this Order.

Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent 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 § 195.302 (**Item 1**), Respondent must prepare a plan to perform pressure testing of the 19 pipeline segments identified in this Final Order as Segments 2–5, 7–12, 14–16, 20–22, 24, 25 and 27, which are also listed on the 1998 Spreadsheet (Exhibit 1-2 to the Violation Report, incorporated by reference). The plan must include a schedule for completing the pressure tests within 1 year from receipt of this Order. Any segments that are idled and that do not contain hazardous liquids may be pressure tested prior to resuming operations. The plan must meet applicable pipeline safety requirements in 49 C.F.R. Part 195, including those in Subpart E. Respondent must submit the plan to the Director for review and approval within 30 days of the receipt of this Order.

2. With respect to the violation of § 195.452(h)(2) (**Item 2**), Respondent must revise its written procedures to ensure timely discovery of conditions when there is an unexpected delay in receiving ILI data from the tool vendor following an integrity assessment. The revised procedures must explain what actions will be taken by the operator to ensure discovery as soon as practicable following a delay, and whenever circumstances render discovery within 180 day to be "impracticable." The procedures must specify the acceptable grounds for any extension of a discovery date due to impracticability. Respondent must submit the revised procedures to the Director for review and approval within 30 days of the receipt of this Order.

3. It is requested that Respondent 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 Respondent and demonstrating good cause for an extension.

[75] Pre-hearing Submittal, p.8 and Exhibit 19.

Failure to comply with this 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. § 190.215, 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. Any petition submitted must contain a statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.215. 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.

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Jeffrey D. Wiese   Date Issued
Associate Administrator
for Pipeline Safety