March 30, 2017

Mr. Mike Morgan
General Manager - Operations
Centurion Pipeline L.P.
5 Greenway Plaza, Suite 110
Houston, TX 77046

Re: CPF No. 4-2014-5028

Dear Mr. Morgan:

Enclosed please find the Final Order issued in the above-referenced case. It makes findings of violation and assesses a reduced civil penalty of $137,100. The penalty payment terms are set forth in the Final Order. This enforcement action closes automatically upon receipt of payment. Service of the Final Order by certified mail is effective as provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. R.M. Seeley, Director, Southwest Region, PHMSA, OPS
Mr. Ahren Tryon, Tryon Law Firm, 4148 Hockaday Drive, Dallas, Texas 75229

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	)	
	)	
Centurion Pipeline, LP,	)	
a subsidiary of Occidental	)	**CPF No. 4-2014-5028**
Petroleum Corporation,	)	
	)	
Respondent.	)	

FINAL ORDER

From April 2013 to February 2014, pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), conducted an on-site pipeline safety inspection of the facilities and records of Centurion Pipeline, LP (Centurion or Respondent) in Texas, New Mexico, and Oklahoma. Centurion operates approximately 2,500 miles of pipeline transporting crude oil in Texas, New Mexico, and Oklahoma.[1]

As a result of the inspection, the Director, Southwest Region, OPS (Director), issued to Respondent, by letter dated November 10, 2014, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Centurion had committed six violations of 49 C.F.R. Part 195 and proposed a civil penalty of $165,900 for the alleged violations. The Notice also proposed certain corrective measures to correct one of the alleged violations.

Centurion responded to the Notice by letter dated December 17, 2014. Centurion contested several of the allegations and requested a hearing. Centurion submitted an additional written response on April 20, 2015 (Supplemental Response). In accordance with 49 C.F.R. § 190.211, a hearing was held in Houston, Texas, on April 30, 2015, before a Presiding Official from the Office of Chief Counsel, PHMSA. After the hearing, Respondent provided a post-hearing statement for the record dated June 26, 2015 (Closing), as well as on September 4, 2015 (Supplemental Closing). Pursuant to § 190.209(b)(7), the Director submitted a written evaluation of Respondent's response material on July 28, 2015 (Recommendation).

[1] This information is reported by Centurion for calendar year 2015 pursuant to 49 C.F.R. § 195.49.

FINDINGS OF VIOLATION

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

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b), which states in relevant part:

> **§ 195.432 Inspection of in-service breakout tanks.**
> (a) . . . .
> (b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, *see* § 195.3). However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).[2]

The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b) by failing to conduct monthly Routine In-Service Inspections of breakout tanks 6832 and 6833 according to API Standard 653 (API 653). At the time of the inspection, inspection reports were requested for Respondent's breakout tanks for the years 2010 through 2013. Respondent could not provide monthly inspection reports for breakout tanks 6832 and 6833 for calendar year 2010, January 2011, February 2011, March 2011, April 2011, and August 2011.

In its Supplemental Response, Respondent claimed the evidence did not support finding the Company had failed to perform the inspections, but only that Respondent was unable to produce documentation of the inspections. Respondent admitted that it could not produce the inspection reports, but argued that it had identified recordkeeping issues on its own prior to the OPS inspection and had fixed the issue. Respondent argued that it "was in continual compliance with the regulation for all of its breakout tanks but two, and the administrative oversight happened over a limited time period."[3]

Respondent presented no evidence that the inspections actually took place. The absence of records supports finding a violation, particularly since records of monthly breakout tank inspections are required to be kept pursuant to the pipeline safety regulations.[4]

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.432(b) by failing to conduct monthly Routine In-Service Inspections of breakout tanks 6832 and 6833 according to API 653.

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[2] API 653, Section 6.3.1.2 states the time between Routine In-Service Inspections shall not exceed one month.

[3] Supplemental Response at 7.

[4] § 195.404(c)(3) (requiring an operator to maintain a record of each required inspection).

Item 2: The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b), which states in relevant part:

> **§ 195.432 Inspection of in-service breakout tanks.**
> (a) . . . .
> (b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, *see* § 195.3). However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).[5]

The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b) by failing to conduct External Inspections of four breakout tanks, 6688, 6965, 6948, and 2722 within the required five-year interval according to API 653.

With respect to tank 6688, Respondent performed an External Inspection on February 5, 2008, and then March 7, 2014, which exceeded the five-year interval by 394 days. With respect to tank 6965, Respondent performed an inspection on August 7, 2008, and then October 10, 2013, which exceeded the five-year interval by 63 days. With respect to tank 6948, Respondent performed an inspection on June 10, 2008, and then March 7, 2014, which exceeded the five-year interval by 258 days. Finally, with respect to tank 2722, Respondent performed an inspection on October 23, 2007, and then June 21, 2013, which exceeded the five-year interval by 240 days.

Respondent did not dispute that it exceeded the external inspection interval with respect to breakout tanks 6688, 6948 and 2722, but disputed breakout tank 6965.[6] Respondent argued that "PHMSA's inspectors may have cited Respondent because the time period between the external inspections was 1890 days, or 5 years and two months. However, this is not a violation of 49 CFR 195.432(b). The follow-up external inspection occurred within *five calendar years* of the previous external inspection."[7]

Section 195.432(b) requires an operator to inspect a breakout tank according to API 653. One of the inspection requirements in the API Standard is Section 6.3.2.1, which requires a visual in-service inspection "conducted at least every 5 years." Respondent argued that "every 5 years" means at least once every five *calendar years*. For example, under Respondent's reasoning, an operator may inspect a tank in January 2010 and then again in December 2015.

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[5] API 653, Section 6.3.2.1 states, "All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must be conducted at least every 5 years or RCA/4N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) whichever is less. Tanks may be in operation during this inspection."

[6] Supplemental Response at 8.

[7] Supplemental Response at 8 (emphasis added).

Respondent's assertion is incorrect. PHMSA has previously determined the five-year inspection period required by § 195.432(b) means five periods of 365 days. In a previous final order, PHMSA found a pipeline operator had violated § 195.432(b) when the operator exceeded the inspection interval of five 365-day periods, even though the operator had performed the inspection within five calendar years.[8] This means that if an operator inspects a tank in January 2010, the tank must be inspected again no later than January 2015.

Respondent cited to another case in which PHMSA found a violation of § 195.432(b) after an operator "never conducted an external inspection in the 5-year period between 2001 and 2006."[9] It is not evident from that decision, however, when or if the operator actually conducted inspections in 2001 and 2006.

Respondent also contended that during development of the API 653 consensus standard "both approaches [five 365-day periods and five calendar years] were accepted and used by the API committee member representatives."[10] I do not find this information persuasive or controlling, most notably because PHMSA has already determined the five-year inspection period means five periods of 365 days.

Respondent exceeded the five-year external inspection period for each of the four tanks listed in the Notice. After considering the evidence, I find that Respondent violated 49 C.F.R. § 195.432(b) by failing to conduct External Inspections of four breakout tanks within the required five-year interval according to API 653.

Item 3: The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b), which states in relevant part:

> **§ 195.432 Inspection of in-service breakout tanks.**
> (a) . . . .
> (b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, *see* § 195.3). However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).[11]

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[8] Enbridge Pipelines (Ozark), L.L.C., CPF No. 4-2010-5008, Item 1, 2010 WL 6531638 (Aug. 17, 2010) (finding violations of the five-year inspection interval for a number of tanks that were inspected within five calendar years, but not within five periods of 365 days).

[9] Belle Fourche Pipeline Co., CPF No. 5-2009-5042, Item 11, 2011 WL 7006607 (Nov. 21, 2011).

[10] Supplemental Closing at 4.

[11] API 653, Section 6.3.3.2(a) states, "When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following: (a) When the corrosion rate is not known, the maximum interval shall be 5 years. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding 5 years."

The Notice alleged that Respondent violated § 195.432(b) by failing to make Ultrasonic Thickness (UT) measurements of breakout tanks at intervals not to exceed five years according to API 653. Specifically, the Notice alleged that Respondent failed to perform the measurements within the maximum interval for breakout tanks 6688, 6965, 6948, and 2722.

With respect to tank 6688, Respondent performed a UT inspection on February 5, 2008, and then March 7, 2014, which exceeded the five-year interval by 394 days. With respect to tank 6965, Respondent performed a UT inspection on August 7, 2008, and then October 10, 2013, which exceeded the five-year interval by 63 days. With respect to tank 6948, Respondent performed a UT inspection on June 10, 2008, and then March 7, 2014, which exceeded the five-year interval by 258 days. Finally, with respect to tank 2722, Respondent performed a UT inspection on October 23, 2007, and then June 21, 2013, which exceeded the five-year interval by 240 days.

In its Supplemental Response, Respondent stated that the five-year interval only applies when the corrosion rate is unknown, and the five-year interval did not apply in this case because Centurion "was well aware of the corrosion rate for the cited breakout tanks."[12] Respondent explained that it had "adequate experience and UT inspection results with a large number of regulated and unregulated crude oil tanks to conclude that the corrosion rate on these tanks" justified "establishing a 10-year [UT] inspection interval."[13] It stressed that the thickness testing went beyond PHMSA's requirements because Respondent "considers the single spot on each course with the minimum thickness for the course in its shell integrity evaluations, rather than averaging the readings to obtain the general thickness, and rate of general corrosion, of the shell."[14] For the breakout tanks at issue, based on its test results, Respondent determined that "a longer [UT] inspection interval was warranted based on the fact that these and all other tanks have experienced such a consistently low rate of internal corrosion since their installation."[15]

OPS responded that Respondent's claim of using Minimum Wall Thickness was invalid. OPS requested and discussed corrosion rates for these tanks on several occasions with Respondent during the inspection. Respondent did not provide any evidence that it had calculated corrosion rates or estimated corrosion rates from tanks in similar service based on thickness measurements. Instead, Respondent stated that it had adequate experience and many UT inspection results. In order to estimate corrosion rates from other tanks in similar service, OPS argued that Respondent needed to perform an adequate Similar Service Assessment of the tanks, as required by API 653.

The evidence demonstrates Respondent did not properly calculate corrosion rates for the tanks at issue. Therefore, Respondent was required to comply with the five-year maximum interval for UT inspections. While Respondent repeated its assertion from Item 2 that the five-year inspection interval means five calendar years, that argument is rejected for the same reasons stated above.

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[12] Supplemental Response at 10.

[13] Supplemental Response at 10.

[14] Supplemental Response at 10.

[15] Supplemental Response at 10.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 195.432(b) by failing to make UT measurements of breakout tanks at intervals not to exceed five years according to API 653.

Item 4: The Notice alleged that Respondent violated 49 C.F.R. §§ 195.202 and 195.264 which state in relevant part:

> **§ 195.202 Compliance with specifications or standards.**
> Each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part.
>
> **§ 195.264 Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.**
> (a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank195.446 Control room management.
> (b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:
> (1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30:
> (i) Impoundment around a breakout tank must be installed in accordance with section 4.3.2.3.2; and
> (ii) Impoundment by drainage to a remote impounding area must be installed in accordance with section 4.3.2.3.1.

The Notice alleged that Respondent violated 49 C.F.R. §§ 195.202 and 195.264 by failing to construct several breakout tanks in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part. Specifically, the Notice alleged that Respondent failed to have specifications that demonstrated breakout tank containment impoundments met the requirements of NFPA 30 referenced in § 195.264. The Notice also alleged that Respondent failed to present documentation, such as surveys or calculations, for any of their breakout tanks constructed after October 2, 2000, to verify containment impoundment volumes met the requirements of NFPA 30.

Respondent did not contest this allegation of violation. Accordingly, after considering the evidence, I find that Respondent violated 49 C.F.R. §§ 195.202 and 195.264 by failing to construct several breakout tanks in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part.

Item 5: The Notice alleged that Respondent violated 49 C.F.R. § 195.452(h)(2), which states in relevant part:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (h) *What actions must an operator take to address integrity issues?* . . . (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 49 C.F.R. § 195.452 by failing to obtain sufficient information no later than 180 days after an integrity assessment to determine if a condition presented a potential threat to the integrity of its pipeline. Specifically, the Notice alleged that on December 3, 2011, Respondent completed an assessment using a T.D. Williamson, Inc. (TDW) SpirALL Magnetic Flux Leakage Multi Data Set tool (SMFL MDS tool or the tool) as part of its continual reassessment of the 16-inch Bretch to Cushing #2 system. The Notice alleged the 180-day deadline to discover conditions was 180 days from the date of the tool run, or no later than May 31, 2012. The Notice alleged that Respondent discovered six immediate repair anomalies on July 11, 2012, which exceeded the 180-day deadline by 41 days.

Respondent argued that it did not fail to meet the 180-day deadline because the 180-day assessment period had "reset" on December 15, 2011, when the Company was told the tool run had failed and would need to be rerun.[16] Respondent explained that when the tool was retrieved on December 3, 2011, it had suffered extensive damage. The damage "called into question whether or not any salvageable data could be extracted from the ILI [inline inspection] tool much less whether such data would be reliable."[17] The tool vendor determined the tool had collected a large quantity of data, but warned Respondent on December 7, 2011, there was evidence that the data might be unreliable. On December 15, 2011, the vendor informed Respondent that the inline inspection (ILI) run was a "Failed Run" due to data quality issues and an inability to retrieve a sufficient data set from the tool for data evaluation and integration under the specified anomaly detection parameters.[18]

Respondent received over 500GB of data from TDW.[19] Despite having "staffing capabilities to look at a very small portion of the data" and having issues with TDW's technology for grading the full ILI run, Respondent was able to examine a sample of the raw data between December 15 and December 20, 2011.[20] Respondent and TDW worked together throughout late December 2011 and January 2012. On January 27, 2012, TDW declared the tool run data usable and agreed

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[16] Closing at 3.

[17] Closing at 3; TDW Aff. at ¶ 13.

[18] Closing at 3; TDW Aff. at ¶ 17.

[19] Closing at 3; TDW Aff. at ¶ 17.

[20] Closing at 4.

to start grading the data.[21] Respondent ultimately identified six anomalies that met its immediate repair criteria.[22]

Respondent claimed that "TDW's acceptance of the data on January 27, 2012, was critical because before that time, Centurion was left with a 'Failed Run' designation and a data set that was of no use given that Centurion could not have fully processed and graded it."[23] Therefore, it argued, the "clock" had stopped on the 180-day assessment and did not reset until TDW agreed the data could be used. In response to OPS's suggestion that Respondent could have processed the data itself,[24] Respondent claimed that "Centurion would not and could not attempt to grade the SMFL Multi Data Set in-line inspection data from TDW."[25]

Respondent further stated that its actions resulted in a "better outcome from a regulatory and safety standpoint than if Centurion had opted for the other legally permissible approach of adhering to the 'Failed Run' designation and conducting a new ILI run within the allotted reassessment interval (October 2012)."[26]

At the hearing, OPS disagreed the 180-day period ever stopped or reset. OPS argued that pursuant to guidance IMP FAQ 4.13, a "reset" is appropriate only when the "quality of the ILI data is suspect and an entire successful rerun of the ILI tool is performed."[27] Moreover, an assessment is considered complete "on the date which final field activities related to the assessment is performed."[28] Because Respondent did not perform a rerun of the assessment, OPS argued that no reset occurred.[29] At the hearing, the Director claimed Respondent had usable data, which meant the 180-day deadline ran from the integrity assessment on December 15, 2011.[30]

Analysis

Pursuant to the integrity management regulations, after an operator performs an integrity assessment, it must "obtain, within 180 days, the assessment data and determine whether conditions presented a threat to the pipeline."[31] Discovery is tied "to the fact that at the

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[21] Closing at 4; TDW Aff. at ¶ 22.

[22] Closing at 5.

[23] Closing at 12.

[24] Closing at 14; Tr. at 87-88.

[25] Closing at 15-16; Mitchell Aff. at ¶¶ 6 to 9, 13 to 14.

[26] Closing at 15-16.

[27] PHMSA IMP FAQ 4.13.

[28] Recommendation at 6-7; PHMSA IMP FAQ 4.13.

[29] Recommendation at 7.

[30] Tr. at 89.

[31] BP Pipelines (North America) Inc., CPF No. 3-2005-5030, Final Order, 2006 WL 4453895, *aff'd*, Decision on Petition for Reconsideration, at 2, 2006 WL 7129217 (Sep. 6, 2006); Alyeska Pipeline

completion of a tool run there are assessment results from which an operator can obtain sufficient information about the condition to determine that condition presents a potential threat to the integrity of the pipeline."[32] In a prior enforcement decision, PHMSA explained that:

> While it is usually evident when an integrity assessment is completed (*e.g.*, at the conclusion of a pressure test or ILI tool run), PHMSA has issued guidance to assist operators in applying the regulation in less common situations. 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."[33]

In the current proceeding, Centurion performed an integrity assessment that was completed on December 3, 2011. The regulation required Respondent to analyze the data and determine whether the conditions in the pipe presented a threat within 180 days. Respondent did not perform a rerun and did not otherwise argue the 180-day requirement was impracticable.

Following the tool run on December 3, 2011, there was approximately 40 days between December 15, 2011, and January 27, 2012, during which Respondent believed the tool data was unusable. But once Respondent understood the data was usable on January 27, 2012, Respondent had more than 120 days before the regulatory deadline to determine the conditions on the pipeline. Respondent has not contended, nor do I find, this constituted an impracticability.

Respondent's notable effort to salvage workable data from a potentially failed tool run is considered below in the penalty assessment section. After considering all of the evidence, however, I find that Respondent violated 49 C.F.R. § 195.452(h)(2) by failing to obtain sufficient information about a condition to determine if the condition presented a potential threat to the integrity of the pipeline no later than 180 days after the integrity assessment.

Item 6: The Notice alleged that Respondent violated 49 C.F.R. § 195.452(h)(4), which states in relevant part:

Service Co., CPF No. 5-2006-5018, Final Order at 2, 2010 WL 6500066, *aff'd* Decision on Petition for Reconsideration, 2010 WL 2228550 (Mar. 1, 2010) (finding that the operator violated 49 C.F.R. § 195.452(h)(2) by failing to promptly obtain, within 180 days after an integrity assessment, sufficient information about anomalous conditions on the pipeline to determine if they present a potential threat to integrity where vendor data was not provided until approximately 330 days after the integrity assessment).

[32] BP Pipelines (North America) Inc., CPF No. 3-2005-5030, Decision on Petition for Reconsideration, at 4, 2006 WL 4453895 (Sep. 6, 2006).

[33] ExxonMobil Pipeline Co., CPF No. 4-2011-5016, Final Order at 21, 2013 WL 4478404 (June 27, 2013) (*citing* PHMSA IMP FAQ 4.13), *aff'd*, Decision on Petition for Reconsideration, 2014 WL 4635422 (July 9, 2014).

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) . . . .
> (h) *What actions must an operator take to address integrity issues?* . . . (4) *Special requirements for scheduling remediation*—(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in Section 451.6.2.2 (b) of ANSI/ASME B31.4 (incorporated by reference, *see* § 195.3). An operator must treat the following conditions as immediate repair conditions:
> (A) Metal loss greater than 80% of nominal wall regardless of dimensions.
> (B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in Sec. 195.3.
> (C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.
> (D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.
> (E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

The Notice alleged that Respondent violated 49 C.F.R. § 195.452(h)(4) by failing to temporarily reduce operating pressure or shut down a pipeline until repairs of immediate conditions were completed. Specifically, the Notice alleged that Respondent discovered six immediate repair conditions on July 11, 2012, but failed to reduce operating pressure or shut down the pipeline until the completion of the repairs on August 3, 2012.

Respondent argued that it did not violate the regulation for two reasons. First, Respondent argued there were no immediate repair conditions. Respondent stated that the locations were incorrectly identified as having dents with metal loss because the ILI tool "produced high-resolution data sets with such granularity that it was capable of picking up what Centurion found to be mill defects."[34] In other words, Respondent had acted on "preliminary information out of an abundance of caution" and upon digging up the conditions found only "very small dent[s] but

[34] Respondent Post-hearing Brief at 25 (emphasis omitted).

no metal loss at each site."[35] Second, Respondent argued that even if the conditions were immediate repair conditions, Respondent complied with the regulation by repairing the defects within about two hours of digging up the conditions.

Analysis

Section 195.452(h)(4) requires a pipeline operator to remediate integrity issues according to a schedule. Certain conditions must be repaired immediately, including any dent on the top of the pipeline that has any indication of metal loss. An operator must immediately reduce pipeline operating pressure or shut down a pipeline that has an immediate repair condition until the repair is completed.

Respondent identified six conditions on July 11, 2012. The conditions were classified as immediate repair conditions causing Respondent to schedule excavations to validate the conditions. Although Respondent may not have known for certain if the conditions met immediate repair criteria until their excavations, Respondent had enough information to classify the conditions and Respondent did in fact classify them as immediate repairs. This obligated Respondent to reduce operating pressure or shut down the pipeline even if classification of the conditions was a conservative estimate based on the information available.[36]

In prior enforcement proceedings, PHMSA has consistently determined that an operator must comply with § 195.452(h)(4) and reduce operating pressure or shut down the pipeline, even if the operator's classification of a condition is a conservative estimate. PHMSA has also determined that § 195.452(h)(4) requires a pressure reduction or shutdown even if the condition meets immediate repair criteria only after factoring in conservative tool tolerances.[37]

After considering the evidence, I find that Respondent violated 49 C.F.R. § 195.452(h)(4) by failing to lower operating pressure or shut down the pipeline upon discovering six immediate repair conditions.

These findings of violation 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 $200,000 per violation for each day of the violation, up to a maximum of $2,000,000 for any related series of violations.

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[35] Respondent Post-hearing Brief at 25.

[36] *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 is a conservative estimate.)

[37] ExxonMobil Pipeline Co., CPF No. 4-2013-5027, Item 5, 2015 WL 7175715, at *17 (Oct. 1, 2015).

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; and any effect that the penalty may have on its 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 $165,900 for the violations cited above.

Item 1: The Notice proposed a civil penalty of $42,400 for Respondent's violation of 49 C.F.R. § 195.432(b), for failing to conduct monthly inspections of two breakout tanks.

Respondent requested that the penalty be eliminated due to the alleged insufficiency of the record compiled by PHMSA with respect to the assessment criteria requirements of 49 C.F.R. § 190.225. Having reviewed the record, including the Violation Report, which discusses each of the assessment factors for each of the violations, I find Respondent's argument does not warrant elimination of the penalty.

With regard to *nature* and *circumstances*, OPS noted in the Violation Report this violation concerned a failure to provide reports that documented monthly tank inspections. Respondent argued that the penalty should be reduced under these factors because the violation was simply a failure to keep records and only involved two tanks for a limited period of time. I reject this argument. Respondent failed to provide any evidence that the required monthly inspections were actually conducted and the time period in question is not insignificant.

With regard to *gravity*, OPS noted in the Violation Report that safe operation was minimally affected. Respondent did not challenge this assessment.

With regard to *good faith*, the Violation Report suggested no credit. Respondent argued that the penalty should be reduced under this factor because the violation only involved two tanks for a limited period of time, the Company complied with the regulation for other tanks, and the Company corrected the non-compliance before the inspection. I reject these arguments. The number of tanks and the period of non-compliance warrants the proposed civil penalty.

With regard to *culpability*, OPS noted in the Violation Report that the operator failed to take appropriate steps to comply with a requirement that was clearly applicable. Respondent argued that the penalty should be reduced under this factor because it discovered the non-compliance and took documented action to address the issue. I find Respondent's argument persuasive. The record reflects that Respondent had monthly inspection records for all breakout tanks after August 2011. Since Respondent discovered and corrected the non-compliance before the OPS inspection, a reduction to the penalty is appropriate.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a reduced civil penalty of $20,800 for violation of 49 C.F.R. § 195.432(b).

Item 2: The Notice proposed a civil penalty of $23,600 for Respondent's violation of 49 C.F.R. § 195.432(b), for failing to conduct five-year external inspections of four breakout tanks.

With regard to *nature* and *circumstances* OPS noted in the Violation Report that this violation concerned a failure to inspect the breakout tanks at the proper interval to evaluate suitability for continued service, which presented a risk to pipeline safety. Respondent argued that the penalty should be reduced because breakout tank 6965 was inspected within five calendar years. Since the finding of violation already explains how Respondent violated the regulation, this argument is rejected.

With regard to *gravity*, OPS noted in the Violation Report that safe operation was minimally affected. Respondent did not challenge this assessment. The Violation Report suggested no credit under the *culpability* and *good faith* factors. In support of reduction of the penalty under these factors, Respondent only repeated arguments that have already been rejected.

As operator of the pipeline facility, Respondent is culpable for this violation of the pipeline safety regulations. I have also weighed Respondent's history of prior offenses and find that when viewed as a whole, it supports the proposed penalty and does not warrant reduction.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $23,600 for violation of 49 C.F.R. § 195.432(b).

Item 3: The Notice proposed a civil penalty of $23,600 for Respondent's violation of 49 C.F.R. § 195.432(b), for failing to make ultrasonic thickness measurements of four breakout tanks.

With regard to *nature* and *circumstances*, OPS noted in the Violation Report that this violation concerned a failure to measure thickness of the tanks at the proper interval to evaluate suitability for continued service, which presented a risk to pipeline safety. Respondent argued that this item should be withdrawn because the Company was well aware of the corrosion rate for the cited breakout tanks based on thickness measurements over the service life of these and other tanks in similar service. Respondent argued that because of these estimates, the five-year interval did not apply. Since the finding of violation already explains how Respondent violated the regulation, these arguments are rejected.

With regard to *gravity*, OPS noted in the Violation Report that safe operation was minimally affected. Respondent did not challenge this assessment. The Violation Report suggested no credit under the *culpability* and *good faith* factors. Respondent argued that if this item is not withdrawn, the penalty should be eliminated or significantly reduced. In support Respondent only repeated arguments that have already been rejected.

As operator of the pipeline facility, Respondent is culpable for this violation of the pipeline safety regulations. I have also weighed Respondent's history of prior offenses and find that when viewed as a whole, it supports the proposed penalty and does not warrant reduction.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $23,600 for violation of 49 C.F.R. § 195.432(b).

Item 5: The Notice proposed a civil penalty of $36,000 for Respondent's violation of 49 C.F.R. § 195.452(h)(2) by failing to obtain sufficient information about a condition to determine if the condition presented a potential threat to the integrity of the pipeline no later than 180 days after an integrity assessment.

Respondent argued that this item should be withdrawn because the Company did not fail to meet the 180-day deadline. Since the finding of violation already explains how Respondent violated the regulation, this argument is rejected.

With regard to *nature*, OPS noted in the Violation Report that this violation concerned an activities violation. Respondent did not challenge this assessment. With regard to *circumstances*, OPS noted in the Violation Report that this violation began on June 1, 2012 and had a duration of 40 days. Respondent argued that there was no violation and that the June 1, 2012 date should be modified to reflect a start date for the "discovery period" of January 27, 2012. Since the finding of violation already explains how Respondent violated the regulation, this argument is rejected.

With regard to *gravity*, OPS noted in the Violation Report that the failure to discover conditions within 180 days of an integrity assessment could result in a hazardous situation to the pipeline. Respondent argued that the penalty should be reduced because there is no evidence in the record that pipeline safety or integrity was compromised. I reject this argument. I find sufficient support in the record that violating the pipeline safety regulations by delaying discovery of unsafe conditions on the pipeline constituted an increased risk that compromised safety.

With regard to *culpability*, I note that Respondent made an effort to salvage workable data from an initial tool run that had, at least at one point, been considered by the tool vendor to be a failed run. This eventually led to a data set that could be analyzed for potential threats to pipeline integrity in a shorter period of time than if Respondent had rerun the tool. Thus I find a reduction to the penalty is appropriate.

Accordingly, having reviewed the record and considered the assessment criteria I assess Respondent a reduced civil penalty of $28,800 for violation of 49 C.F.R. § 195.452(h)(2).

Item 6: The Notice proposed a civil penalty of $40,300 for Respondent's violation of 49 C.F.R. § 195.452(h)(4) by failing to temporarily reduce operating pressure or shut down the pipeline until repairs of immediate conditions were completed.

With regard to *nature* and *circumstances*, OPS noted in the Violation Report that this violation concerned a failure to temporarily reduce operating pressure or shut down the pipeline until classified immediate repairs were completed. Respondent argued that this item should be withdrawn because there were no immediate repair conditions and that the defects were repaired within two hours of digging up the conditions. Since the finding of violation already explains how Respondent violated the regulation, these arguments are rejected.

With regard to *gravity*, OPS noted in the Violation Report that the failure to reduce pressure upon discovery of immediate repair conditions may result in the release of product into the environment. Respondent argued that the penalty should be reduced because there is no evidence in the record that pipeline safety or integrity was compromised. I reject this argument. I find sufficient support in the record that Respondent's failure to comply with the pipeline safety regulations that required the Company to immediately reduce pressure or shut down the pipeline due to unsafe conditions constituted an increased risk that compromised safety.

The Violation Report suggested no credit under the *culpability* and *good faith* factors. Respondent only repeated arguments that have already been rejected.

As operator of the pipeline facility, Respondent is culpable for this violation of the pipeline safety regulations. I have also weighed Respondent's history of prior offenses and find that when viewed as a whole, it supports the proposed penalty and does not warrant reduction.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $40,300 for violation of 49 C.F.R. § 195.452(h)(4).

In summary, Respondent is assessed a total civil penalty of **$137,100**.

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

Failure to pay the $137,100 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 Item 4 in the Notice for violations of 49 C.F.R. §§ 195.202 and 195.264. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601. The Director indicated that Respondent has taken the following actions specified in the proposed compliance order:

> With respect to the violations of §§ 195.202 and 195.264 (**Item 4**), Respondent evaluated its tank dike areas and ensured that the dike areas meet the impoundment criteria. Centurion has provided documentation to PHMSA in the form of current surveys, drawings, and calculations that show the containment is in compliance with the applicable requirements.

I find that compliance has been achieved with respect to this violation. Therefore, the compliance terms proposed in the Notice are not included in this Order.

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. Any petition submitted 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. The other terms of the order, including 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.

March 30, 2017

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Date Issued