NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 10, 2014

Mr. Bill Moyer
President
Centurion Pipeline, L.P.
5 Greenway Plaza, Suite 110
Houston, TX 77046

CPF 4-2014-5028

Dear Mr. Moyer:

On April 2013 to February 2014, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code inspected your procedures, records and pipeline facilities in Texas, New Mexico, and Oklahoma.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **195.432 Inspection of in-service breakout tanks.**

> **(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).**

Centurion did not inspect the physical integrity of in-service atmospheric breakout tanks according to API Standard 653. API Standard 653, Section 6.3.1.2 states the Routine In-Service Inspections shall not exceed one month. Centurion's Liquid Operations Manual, procedure P-195.432, Inspection of In-Service Breakout Tanks, also states the frequency for Routine In-service Inspection is monthly. Their Monthly Inspection of In-service Breakout Tanks Form F-195.432(b) states the inspection form will be retained for five years.

At the time of the inspection, inspection reports were requested for Centurion's breakout tanks for the years 2010 through 2013. Breakout tanks 6832 and 6833 are located in Centurion's Wasson Facility along with three other breakout tanks, 6719, 6830, and 6831. Monthly inspection reports were provided for tanks 6719, 6830, and 6831 for the time period as requested. Centurion failed to provide monthly Routine In-Service Inspection reports for breakout tanks 6832 and 6833 to demonstrate the tanks were inspected as required by 49 CFR 195 and API Standard 653, Section 6.3.1.2, incorporated by reference. Specifically, Centurion did not provide monthly inspection reports for breakout tanks 6832 and 6833 for all of year 2010, January 2011, February 2011, March 2011, April 2011, and August 2011.

2. **195.432 Inspection of in-service breakout tanks.**

> **(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).**

Centurion did not inspect the physical integrity of in-service atmospheric breakout tanks according to API Standard 653. 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."

Centurion's Liquid Operations Manual, procedure P-195.432, Inspection of In-Service Breakout Tanks, also states the frequency for External Inspections is "Every 5 years". Their Monthly

Inspection of In-service Breakout Tanks Form F-195.432(b) states the inspection form will be retained for five years.

The following table summarizes the tanks that exceeded the 5 year interval.

Tank	Nominal Capacity (bbl.)	Date Built	Roof Type	Shell Construction	Bottom Lining	API 653 External Previous	API 653 External Current	External Interval
6688	85000	1950	EFR	Welded	None	2/5/2008	3/7/2014	>5
6965	111000	1950	EFR	Welded	Claymax	8/7/2008	10/10/2013	>5
6948	30000	1950	EFR	Welded	None	06/10/08	3/7/2014	>5
2722	80000	1957	EFR	Welded	Claymax	10/23/2007	6/21/2013	>5

The previous External Inspection for tank 6688 was performed on February 5, 2008, during an out of service internal inspection. The final out of service inspection report demonstrates there was no corrosion rate calculated or established for Tank 6688. According to API 653, Section 6.3.2.1., the External Inspection interval is 5 years since the corrosion rate is unknown. The following External Inspection was performed on March 7, 2014, which exceeded the 5 year interval by 394 days.

The previous External Inspection for tank 6965 was performed on August 7, 2008, during an out of service internal inspection. Centurion did not provide documentation or reports demonstrating a corrosion rate was calculated or established for Tank 6965. According to API 653, Section 6.3.2.1., the External Inspection interval is 5 years since the corrosion rate is unknown. The following External Inspection was performed on October 10, 2013, which exceeded the 5 year interval by 63 days.

The previous External Inspection for tank 6948 was performed on June 10, 2008, during an in-service inspection. Centurion did not provide documentation or reports demonstrating a corrosion rate was calculated or established for Tank 6948. According to API 653, Section 6.3.2.1., the External Inspection interval is 5 years since the corrosion rate is unknown. The following External Inspection was performed on March 7, 2014, which exceeded the 5 year interval by 258 days.

The previous External Inspection for tank 2722 was performed on October 23, 2007, during an out of service inspection. Centurion did not provide documentation or reports demonstrating a corrosion rate was calculated or established for Tank 2722. According to API 653, Section 6.3.2.1., the External Inspection interval is 5 years since the corrosion rate is unknown. The following External Inspection was performed on June 21, 2013, which exceeded the 5 year interval by 240 days.

3. **195.432 Inspection of in-service breakout tanks.**

(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).

Centurion did not inspect the physical integrity of in-service atmospheric breakout tanks according to API Standard 653. API 653, Section 6.3.3.2 states, 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."

Centurion's Liquid Operations Manual, procedure P-195.432, Inspection of In-Service Breakout Tanks, states the frequency for Ultrasonic Thickness Inspections is "Every 5 years". Their Monthly Inspection of In-service Breakout Tanks Form F-195.432(b) states the inspection form will be retained for five years.

Centurion failed to perform "Ultrasonic Thickness Inspections" within the maximum interval of five years prescribed by API 653 Section 6.3.3.2, for the following breakout tanks that have unknown corrosion rates:

Tank	Nominal Capacity (bbl.)	Date Built	Roof Type	Shell Construction	Bottom Lining	API 653 External Previous	API 653 External Current	External Interval
6688	85000	1950	EFR	Welded	None	2/5/2008	3/7/2014	>5
6965	111000	1950	EFR	Welded	Claymax	8/7/2008	10/10/2013	>5
6948	30000	1950	EFR	Welded	None	06/10/08	3/7/2014	>5
2722	80000	1957	EFR	Welded	Claymax	10/23/2007	6/21/2013	>5

The previous Ultrasonic Thickness Inspection (UTI) for tank 6688 was performed on February 5, 2008 during an out of service internal inspection. The final out-of-service inspection report demonstrates there was no corrosion rate calculated or established for Tank 6688. According to API 653, Section 6.3.3.2., the UTI interval is 5 years since the corrosion rate is unknown. The current UTI was performed on March 7, 2014, which exceeded the 5 year interval by 394 days.

The previous UTI for tank 6965 was performed on August 7, 2008, during an out of service internal inspection. The final out-of-service inspection report demonstrates there was no corrosion rate calculated or established for Tank 6965. According to API 653, Section 6.3.3.2., the UTI interval is 5 years since the corrosion rate is unknown. The current UTI was performed on October 10, 2013, which exceeded the 5 year interval by 63 days.

The previous UTI for tank 6948 was performed on June 10, 2008, during an in-service inspection. Centurion did not provide documentation or reports demonstrating a corrosion rate was calculated or established for Tank 6948. According to API 653, Section 6.3.3.2., the UTI interval is 5 years since the corrosion rate is unknown. The current UTI was performed on March 7, 2014, which exceeded the 5 year interval by 258 days.

The previous UTI for tank 2722 was performed on October 23, 2007, during an out of service inspection. The final out-of-service report demonstrates there was no corrosion rate calculated or established for Tank 2722. According to API 653, Section 6.3.3.2., the UTI interval is 5 years since the corrosion rate is unknown. The current UTI was performed on June 21, 2013, which exceeded the 5 year interval by 240 days.

4. §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.

Impoundment, protection against entry, normal/emergency venting
(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.

Centurion failed to construct several breakout tanks in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part. Centurion failed to provide comprehensive written specifications or standards to demonstrate breakout tank containment impoundments met the requirements of NFPA 30 referenced in §195.264. Centurion also failed to present documentation (surveys, calculations) for any of their breakout tanks constructed after October 2, 2000, that verified the containment impoundment volumes met the requirements of NFPA 30.

Centurion owns several breakout tanks throughout west Texas, New Mexico, and Oklahoma. Ten of them were constructed from 2009 to 2012. Tanks 6693, 6832, 6692, 160100, 160101, 6691, 6833, were constructed in 2009, and tanks 6991, 7101, and 160102 were constructed in 2012. The impoundment requirements are contained in several paragraphs throughout the NFPA 30 standard.

5. 195.452 Pipeline integrity management in high consequence areas.

(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.

Centurion failed 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.

On December 3, 2011, Centurion completed a TDW Spirall Magnetic Flux Tool run as part of their continual reassessment of their 16-inch Bretch to Cushing #2 system. This would place the 180 day deadline on or about May 31, 2012. Centurion determined six anomalies met the immediate repair criteria on July 11, 2012, which is 220 days after the tool run was completed. Centurion was unable to demonstrate that the 180 day requirement was impracticable.

6. 195.452 Pipeline integrity management in high consequence areas.

(h) What actions must an operator take to address integrity issues?
(4) Special requirements for scheduling remediation
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:

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.

Centurion failed to maintain safety by temporarily reducing operating pressure or shutting down the pipeline until repairs of immediate conditions that they identified were completed. Centurion failed to reduce the operating pressure, shut down the pipeline or make repairs and evaluations of six immediate repair conditions in an HCA segment that met the immediate repair condition criteria.

Centurion conducted an assessment using TDW's ILI tool on their 16-inch Bretch to Cushing #2 system. There were six anomalies identified, in an HCA segment, by TDW as "deformation (above 4 and 8"oclock positions) … w/associated Metal Loss" which meets the definition of an immediate repair condition per 195.452(h)(4)(i)(C). These determinations were accepted by Centurion. These immediate repairs were located in an HCA segment between the El Reno facility and Cushing segment at MP's 73.53, 74.57-A, B, C, D (four at this location). The immediate repair at MP 84.54 was located approximately three miles upstream of the El Reno facility, on the Bretch to El Reno segment. The six anomalies were identified and were sent to operations for rehab repairs on July 12, 2012. The repairs on the six immediate repairs began 15 days after on July 27, 2012 and were completed 22 days later, on August 3, 2012.

Centurion did not reduce the operating pressure after six immediate repair anomalies were discovered. Pressure charts provided by Centurion demonstrate the El Reno discharge pressure from July 12, 2012 to the end of repairs (August 3, 2012) that affected the immediate repair anomalies at MP 73.52, 74.57A, B, C, and D. The discharge operating pressure readings range from approximately 540 psi to approximately 620 psi, which demonstrates there was no pressure reduction.

Centurion's Integrity Management Plan Section 7.1.2 -Action Required Upon Discovery of an Immediate Repair Condition states, "Upon discovery of an immediate Repair condition, the Manager, Pipeline Integrity will notify the Regional Manager of the need to either shut down the line or reduce the operating pressure as possible until the Immediate Repair Condition is repaired or remediated. The Regional Manager will make operating pressure changes as directed by the Manager, Pipeline Integrity. The Manager, Pipeline Integrity will use guidance in ASME B31.4 for determining the reduction in operating pressure for corrosion anomalies. For all other types of anomalies or if the formula yields a higher operating pressure, the minimum pressure reduction will not be less than twenty percent of the highest operating pressure occurring at the anomaly's location during the preceding sixty days."

ASME B31.4 is not applicable for calculating the temporary pressure reduction required for top-side dents with metal loss. Pressure must be reduced for other types of immediate repair conditions, but operators must develop appropriate engineering justification for the amount of pressure reduction. A reduction in operating pressure is intended to provide an additional safety margin until the defect can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present (i.e., pressures for which safety has been demonstrated). These may be well below the 'maximum operating pressure' for the pipe.

Pressure charts provided by Centurion via email, shows pressures from the preceding two months of the day of discovery. The El Reno discharge pressure chart affecting the immediate repair anomalies at MP 73.52, 74.57A, B, C, and D, shows the highest discharge pressure was approximately 700 psi which occurred on approximately June 5, 2012. Centurion needed to take a minimum of a 20% pressure reduction of the highest operating pressure in the preceding two months as per their IMP procedure 7.1.2.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations.

The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violation(s) and has recommended that you be preliminarily assessed a civil penalty of $165,900 as follows:

Item number	PENALTY
1	$42,400
2	$23,600
3	$23,600
5	$36,000
6	$40,300

Proposed Compliance Order

With respect to items 4 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Centurion Pipeline, L.P. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. All material you submit in response to this enforcement action may be made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

In your correspondence on this matter, please refer to **CPF 4-2014-5028** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Compliance Proceedings

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Centurion a Compliance Order incorporating the following remedial requirements to ensure the compliance of Centurion with the pipeline safety regulations:

Item 1: In regard to Item Number 4 of the Notice pertaining to verifying the containment dike volume for the various breakout tanks, Centurion must evaluate its tank dike areas and ensure that the dike areas meet the impoundment criteria. Centurion must provide documentation to PHMSA in the form of current surveys, drawings, and/or calculations that show the containment complies with the applicable requirements of NFPA 30, incorporated by reference into Part 195.

Item 2: Pertaining to Item 1 of the Proposed Compliance Order, Centurion must complete the required documentation within 90 days of the date of the Compliance Order.

Item 3: It is requested (not mandated) that Centurion Pipeline, L.P. maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to R. M. Seeley, Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration. 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.