NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 12, 2012

Mr. Kevin Bodenhamer
Senior Vice President
Enterprise Crude Pipeline, LLC
1100 Louisiana Street
Houston, TX 77002

CPF 4-2012-5007

Dear Mr. Bodenhamer:

On April 11-15, 2011, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code were onsite and inspected your Enterprise East Cushing Terminal in Cushing, OK.

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 violation(s) are:

1. **195.264 Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.**

   Impoundment, protection against entry, normal/emergency venting
   (a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tanks.
   (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.
(2) For tanks built to API 2510, the installation of impoundment must be in accordance with section 5 or 11 of API 2510 (incorporated by reference, see §195.3).

Enterprise (the Operator) did not have documentation (surveys, calculations) verifying that the containment dike volume at the East Cushing Terminal met the applicable NFPA 30 requirements after constructing additional tanks within the diked area as recently as 2006. The documentation was requested during the inspection but not provided by the Operator. The Enterprise procedure EGS E-6310, Secondary Containment & Leak Detection, Section 5.0, Diking, specifies requirements but the Operator was not able to produce documentation showing that these procedures had been followed.

2. 195.432 Inspection of in-service breakout tanks.

(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.
(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).
(c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.
(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.

The corrosion rate used by Enterprise to establish the external inspection intervals was not based on actual shell thickness measurements for a given tank or a documented similar service assessment performed according to the requirements the version of API 653, Appendix H. According to interviews performed during the inspection and email correspondence from Enterprise, a corrosion rate of 0.003 inches per year was used if there was no known corrosion rate. The incorporated version of API 653 requires that the external inspection "…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." Therefore, an Operator must determine an actual corrosion rate through measurement or determine a corrosion rate based on a similar service study performed according to the requirements of API 653 Appendix H to establish the external inspection interval.

Pertaining to the Operator’s procedural requirements for external inspections, at the time of the inspection or afterwards, Enterprise presented several breakout tank inspection procedures that included external inspection requirements, so it is not clear which procedure(s) the Operator used. The procedures included Enterprise Products STD.9502, Inspection and Testing of Aboveground Storage Tanks, EPCO, Inc., STD.9503, DOT Breakout Tank Integrity Testing, and EPCO, Inc., EGS E-6320, Tank Inspection Repair, Alteration and Reconstruction. The wording for the external inspection requirements varied between procedures but each intended to convey the external inspection requirements of API 653, although sometimes incorrectly. For example, EPCO, Inc., STD.9503 states that a risk-based inspection assessment may be used to establish the external inspection interval. However, the version of API 653 incorporated by reference states in Section E.3, Technical Inquiry Responses, 653-I-02/03, “RBI can be applied to internal inspection intervals only.” If the operator followed this procedure, it would not be consistent with the requirements of Part 195 for external breakout tank inspections.

Also, at the time of the inspection, Enterprise had set the ultrasonic thickness inspection intervals to the maximum of 15 years. For ultrasonic inspections the version of API 653 incorporated by reference states, “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.” API 653 goes on to state “When the corrosion rate is known, the maximum interval shall be the smaller of RCA/2N 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) or 15 years.” According to interviews with Enterprise personnel during the inspection and email correspondence from Enterprise, the operator did not determine actual corrosion rates or perform a similar service assessment to establish a corrosion rate that would provide the basis allow the ultrasonic corrosion inspection interval to be 15 years. Enterprise has notified PHMSA after the inspection that it was changing its ultrasonic inspection intervals to 5 years.

Pertaining to internal breakout tank inspections, Enterprise employs a risk-based inspection (RBI) methodology to determine the internal inspection intervals. This is allowed by section 6.4.3 of the version of API 653 incorporated by reference. However, the analysis methods used to determine the product side, soil side, and external corrosion rates and the accuracy of these methods and corrosion rates must be considered in the risk-based methodology. Interviews during the inspection as well as email correspondence from Enterprise did not provide adequate justification for the basis of the floor corrosion rates used in the risk-based methodology (from actual measurements or similar service) to determine the internal inspection intervals. As an example of the issue, the API 653 inspection report for tank 1003 in Cushing, OK, performed in April-May 2009, states “A new bottom is to be installed (per client). Consideration should be given to inspecting the new bottom within ten (10) years to establish a corrosion rate (ref. API 653, Para. 6.4.2.2).” Despite not having a measured corrosion rate for the floor, a documented similar service assessment, or other justified means for the floor corrosion rates used, Enterprise set the internal inspection interval for tank 1003 to 15 years as shown on the Tank Data form completed by the Operator. According to API 653, section 6.4.3, Alternative Internal Inspection

Interval, the Operator must consider in an RBI assessment, “c. The methods used for determination of the shell and bottom plate thickness,” “d. The availability and effectiveness of the inspection methods and quality of the data collected,” and “e. The analysis methods used to determine the product side, soil side, and external corrosion rates and the accuracy of these methods and corrosion rates.”

3. 195.432 Inspection of in-service breakout tanks.

> **(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.**
> **(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).**
> **(c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.**
> **(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.**

Enterprise did not make the repairs recommended by the API 653 inspections or did not have adequate documentation to show that the Operator evaluated the recommended repairs and made a determination that the repairs were not needed. For example, notes taken during the inspection from the review of an API 653 inspection report for tank 1007 at the Enterprise East Cushing, OK terminal indicated that there were cracks in the ringwall that needed to be addressed by the Operator. Photographs of the ringwall taken during the PHMSA field inspection showed that the cracks had not been repaired. No documentation was found in the Operator’s records indicating the ringwall repair recommendations had been evaluated and that a decision made and justified that repairs were not required. Another similar example of unrepaired ringwall cracks was found for tank 1008 during the field inspection. Examples of additional significant inspection findings can be found in the API 653 inspection reports for tank 1008 dated August 2, 2001 and tank 1009 dated March 6, 2000. Documentation for repair of each of the findings or justification why the repairs were not made was not found in the Enterprise breakout tank files. The field inspection could not verify that all of the repairs were made. The Enterprise breakout tank records must address the API 653 inspection significant findings and document the repairs or provide justification why the repairs were not needed to ensure the safety of the tank.

4. 195.505 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;
(b) Ensure through evaluation that individuals performing covered tasks are qualified;
(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;
(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195;
(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
(f) Communicate changes that affect covered tasks to individuals performing those covered tasks; and
(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.
(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and
(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

During a Protocol 9 Operator Qualification inspection an Operator employee was asked to perform a routine monthly breakout tank inspection and the technician did not use the prescribed inspection checklist during the inspection, had difficulty in recalling specific items to be checked, difficulty in explaining the basis for determining when an issue should be documented, and difficulty recalling the specific Abnormal Operating Conditions identified by the operator for the task.

Warning Items

With respect to item(s) 2 through 4 we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these item(s). Be advised that failure to do so may result in Enterprise being subject to additional enforcement action.

Proposed Compliance Order

With respect to item(s) 1 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Enterprise. 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. Be advised that all material you submit in response to this enforcement action is subject to being 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 4-2012-5007** 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 Enterprise Crude Pipeline (Enterprise), LLC a Compliance Order incorporating the following remedial requirements to ensure the compliance of Enterprise with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to verifying the containment dike volume at the East Cushing, OK terminal, Enterprise must provide documentation to PHMSA in the form of surveys, drawings, and calculations that show the secondary containment after the addition of the most recent tank at the East Cushing, OK terminal complies with the applicable requirements of NFPA 30, incorporated by reference into Part 195.

3. Enterprise must complete the required documentation within 90 days of the date of the Compliance Order.

4. It is requested (not mandated) that Enterprise 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.