NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 4, 2013

Mr. Richard Adams
Vice President, U. S. Operations
Enbridge Pipelines, LLC
City Center Office
1409 Hammond Ave.
Superior, WI 54880-5247

CPF 4-2013-5004

Dear Mr. Adams:

In November 2011, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your Enbridge Pipeline, LLC Cushing Terminal (Enbridge) 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. **§195.432 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).

API Standard 653 “Tank Inspection, Repair, Alteration, and Reconstruction” (3rd edition, December 2001, includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)).

6.3.2.1 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.

(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.

Enbridge did not properly determine the shell corrosion rates necessary to establish the external inspection intervals as required by API Standard 653, 6.3.2.1, incorporated by reference into Part 195. Paragraph 6.3.2.1 of API Standard 653 requires the external inspection interval to be determined by subtracting the minimum required shell thickness from the measured shell thickness and dividing the result by four times the actual shell corrosion rate. The shell corrosion rate is calculated by dividing the measured metal loss by the time over which it occurred. The metal loss is determined by subtracting a more recent shell thickness measurement from a shell thickness measurement made earlier in time at the same location on the breakout tank. The change in shell thickness is then divided by the time interval between measurements to determine a corrosion rate. Some of the Enbridge calculations of metal loss were negative, indicating the shell plate had increased in thickness over time. This occurred because the methodology used by Enbridge to measure the shell plate thickness was flawed. Consequently, tanks #1014, #2228, and #3011 had improperly calculated inspection intervals.

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).

(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.

API Standard 653 "Tank Inspection, Repair, Alteration, and Reconstruction" (3rd edition, December 2001, includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)).

6.9.3.2 It is the responsibility of the owner/operator to review the inspection findings and recommendations, establish a repair scope, if needed, and determine the appropriate timing for repairs, monitoring, and/or maintenance activities. Typical timing considerations and examples of repairs are: a. Prior to returning the tank to service—repairs critical to the integrity of the tank (e.g., bottom or shell repairs). b. After the tank is returned to service—minor repairs and maintenance activity (e.g., drainage improvement, painting, gauge repairs, grouting, etc.). c. At the next scheduled internal inspection—predicted or anticipated repairs and maintenance (e.g., coating renewal, planned bottom repairs, etc.). d. Monitor condition for continued deterioration—(e.g., roof and/or shell plate corrosion, settlement, etc.). The owner/operator shall ensure that the disposition of all recommended repairs and monitoring is documented in writing and that reasons are given if recommended actions are delayed or deemed unnecessary.

4.5.2 Foundation Repair or Replacement

4.5.2.1 If there is a need for foundation repair or replacement, foundations shall be restored to the tolerance limits of 10.5.6.

4.5.2.2 Concrete pads, ringwalls, and piers, showing evidence of spalling, structural cracks, or general deterioration, shall be repaired to prevent water from entering the concrete structure and corroding the reinforcing steel.

C.1.1.1 Concrete Ring

d. Check that runoff rainwater from the shell drains away from tank.

C.1.1.5 Site Drainage

a. Check site for drainage away from the tank and associated piping and manifolds.

Enbridge did not complete some breakout tank repairs identified by the API 653 standard and the required inspections as necessary to maintain a tank condition suitable for safe operation or in the alternative provide engineering justification for not making the repairs. The issues include failing to make repairs to cracked or deteriorated ringwalls and failing to modify the grade so that water drains away from the tanks. Inadequate repairs were found on tanks #1014, #1015, #1016, #1153, and #1154.

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).

(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.

API Standard 653 "Tank Inspection, Repair, Alteration, and Reconstruction" (3rd edition, December 2001, includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)).

6.3.1.2 The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month.

Enbridge did not perform the monthly inspections of its breakout tanks as required by 49 CFR 195 and API Standard 653, incorporated by reference. According to the Enbridge Work Order List Report for monthly breakout tank inspections, breakout tank 1181 was inspected on January 4, 2011 but not inspected again until March 1, 2011, a span of 56 days with no February inspection. Breakout tank 1182 was inspected on January 29, 2011 but not inspected again until March 7, 2011, a span of 37 days with no February inspection. The January Work Order List indicates that breakout tank 3364 was not inspected until February 1 but inspected again on February 28 with no January inspection. There are several additional Cushing Terminal breakout tanks where the inspections are not being performed according to the API Standard 653 requirement. Enbridge must modify its inspection schedule to meet the requirement of performing API Standard 653 routine in-service inspections.

4. §195.565 How do I install cathodic protection on breakout tanks?

After October 2, 2000, when you install cathodic protection under Sec. 195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels (79.5m3) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the system in accordance with API Recommended Practice 651. However, installation of the system need not comply with API Recommended Practice 651 on any tank for which you note in the corrosion control procedures established under Sec. 195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

§195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this Subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169 (incorporated by reference, see § 195.3).

Enbridge did not meet at least one of the applicable criteria for cathodic protection on some Cushing Terminal breakout tanks as required by API RP 651 and NACE SP 0169. The Operator uses the 100 mV polarization criterion on a portion of the breakout tanks and the -850 mV with consideration of IR drop criterion on others. The inspection found several breakout tanks where Enbridge was not meeting the specified criteria or had not taken the appropriate measurements to determine if the specified criterion was being met.

For example, Enbridge states that the 100mV criterion is being used tank #1153 but only energized (on) readings were taken during the 2011 annual survey. To determine if the 100 mV criterion is being met, the operator must compare the polarized measurement, eliminating IR drop, (instant off) to the depolarized measurement. However, no instant off readings were taken in 2011 to determine if the 100mV of polarization was achieved. Without instant off readings, the only check that can be made is against the -850mV with consideration of IR drop criterion (energized reading). Several of the energized readings taken using the profile tube did not meet the -850mV criterion even before considering IR drop (20 feet, -625mV, 25 feet, -607mV, 30 feet, -684mV, 40 feet, -702mV).

As another example, the records for tank #1295 do not show any depolarization measurements so one of the -850mV criteria must be applied. Some of the structure-to-soil measurements did not meet either of the -850mV criteria listed in NACE SP0169 or API RP651 for 2009, 2010, or 2011. Enbridge records indicate that a new groundbed was installed in 2010 but some of the 2011 structure-to-soil readings were still not meeting one of the -850 mV criteria.

Tank #2211, which was cited in a previous enforcement action (CPF 4-2010-5008) for exceeding the API 653 internal inspection interval, was diagnosed with a depleted groundbed as early as 2007. The tank was scheduled to be taken out of service in 2012 but Enbridge continued to operate the tank with deficient cathodic protection in 2009, 2010, and 2011.

Other examples of tanks not meeting one of the cathodic protection criteria include #1182, #2218, #1320, #2212, #2215, and #2223.

5. §195.581Which pipelines must I protect against atmospheric corrosion and what coating material may I use?

You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section. (b) Coating material must be suitable for the prevention of atmospheric corrosion. (c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will- (1) Only be a light surface oxide; or (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

§195.583 What must I do to monitor atmospheric corrosion control?

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by Sec. 195.581.

Enbridge has not consistently applied coating material (paint) to all of its breakout tanks in the Cushing Terminal suitable for the prevention of atmospheric corrosion as required by 195.581(a). Enbridge has several tanks at their Cushing, OK terminal that have not been completely painted and have an atmospheric corrosion scale on the unpainted exterior surface. Enbridge argues that the corrosion scale is a form of protective coating and that the tanks do not need to be painted to protect them from atmospheric corrosion. However, according to the Operator, the bottom four feet on these tanks has been painted "to protect the floor-to-shell ("chime") weld and appurtenance area." The acknowledgment that a portion of the tank had to be painted for protection from atmospheric corrosion indicates that corrosion damage is occurring and constitutes a contradiction to the Operator's argument that the corrosion scale is adequate protection from atmospheric corrosion.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any 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 $78,700 as follows:

Item number	PENALTY
1	$33,700
4	$45,000

Warning Items

With respect to item(s) 2, 3, and 5 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 Enbridge Pipeline being subject to additional enforcement action.

Proposed Compliance Order

With respect to item(s) 1 and 4 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Enbridge Pipeline. 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 4-2013-5004** 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 Enbridge a Compliance Order incorporating the following remedial requirements to ensure the compliance of Enbridge with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to improperly determining the shell corrosion rates, Enbridge must modify its program to correctly determine the shell thicknesses and corrosion rates on all of the breakout tanks in the Cushing Terminal and re-determine the external inspection intervals for each breakout tank.

2. In regard to Item Number 4 of the Notice pertaining to failing to achieve adequate cathodic protection on some of the breakout tanks and piping in the Cushing Terminal, Enbridge must take appropriate actions to remedy all cathodic protection deficiencies and show by structure-to-soil measurements that one or more of the cathodic protection criteria listed in NACE SP0169 or API RP651 has been achieved.

3. In regard to Item Number 1 of the Notice, Enbridge must submit, for PHMSA approval, a shell thickness measurement procedure within 30 days of receipt of this Order. The Operator must then complete shell thickness re-measurements according to the approved procedure for all Cushing Terminal breakout tanks within 180 days of receiving PHMSA approval for the procedure. The Operator must also propose an initial shell re-measurement interval appropriate to determine a valid shell corrosion rate, and once the second measurement has been completed, recalculate the external inspection interval for all Cushing Terminal breakout tanks. Enbridge must complete the entire process to properly determine the external inspection intervals within 60 months from of receipt of this Order. In regard to Item Number 4 of the Notice, Enbridge must submit to PHMSA, a plan, with dates, to correct all cathodic protection deficiencies within 30 days of receipt of this Order. The Operator must complete correction of all deficiencies within 12 months of receipt of this Order.

4. It is requested (not mandated) that Enbridge Pipeline, LLC 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.