Enbridge Energy
26 E Superior Street, Suite 309
Duluth, MN 55811
www.enbridgepartners.com

Shaun Kavajecz, Sr. Manager
U.S. Pipeline Compliance
Tel 218 464 5740
shaun.kavajecz@enbridge.com

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VIA ELECTRONIC TRANSMISSION

Mr. Rodrick M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
8701 South Gessner, Suite 1110
Houston, Texas 77074

RE: CPF 4-2013-5004

Dear Mr. Seeley:

In November 2011, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) Southwest Region inspected Enbridge Pipelines (Ozark) L.L.C.'s (Enbridge) Cushing Terminal facility in Cushing, Oklahoma.

On March 11, 2013, Enbridge received PHMSA's Notice of Probable Violation ("NOPV"), Proposed Civil Penalty and Proposed Compliance Order dated March 4, 2013. Enbridge appreciates the opportunity to respond to the alleged deficiencies and offers the following response. The general format of our response lists the abbreviated probable violations in PHMSA's Notice, followed by our response.

PHMSA Finding

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 required 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.

Enbridge Response

When Enbridge acquired the Cushing facility, as built tank information was not available. For situations where the nominal thickness is unknown, industry-accepted inspection practice is to use the nearest standard plate thickness in the corrosion growth rate calculation.

The corrosion growth rate calculation used by Enbridge is the calculation set forth by API 653 and used industry-wide. There are many variables that could affect the calculations, such as steel tolerances, measurement differentials, etc. During inspections, the minimum of the actual thickness measurements is used in the calculation to add further conservatism to the inspection interval. Considering the tolerance variables, it is feasible have a measurement result in “negative corrosion growth” which would indicate that the corrosion growth rate is negligible.

Enbridge has developed the multiyear program to take baseline thickness measurements of the tanks to calculate re-inspection intervals. Enbridge is currently in the first phase of a multiyear program to establish corrosion growth rates on tank shell thickness of affected tanks within Cushing Terminal. In 2013, Enbridge will be completing base line thickness measurements on tanks where original records are not available due to missing records at the time of acquisition. Measurements will be taken utilizing a new procedure that is currently being vetted internally. The procedure will be sent to PHMSA by May 8, 2013, in accordance with the Proposed Compliance Order.

In 2014, Enbridge will re-inspect the previously inspected tanks to determine the corrosion growth rate. Current methodology for determining tank inspection intervals for external inspection is stated in API 653 6.3.2.1, which is the lesser of 5 years or RCA/4N.

PHMSA Finding

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, 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.

Enbridge Response

After tank inspection reports have been received, Enbridge creates a corrective action/reconciliation report to document and outline actions to be taken in response to items identified in the tank inspection report. Each item identified in the tank inspection report will have a corresponding action or engineering justification for no action needed, delaying action, or monitoring. Previous inspections for the tanks outlined in item 2 of the NOPV (1014, 1015, 1016, 1153, and 1154) indicated no immediate need for repair on ringwalls or grading. The corrective action/reconciliation report indicated monitoring as the remedial action for these situations. Enbridge is taking the following actions to further assess and mitigate, if necessary.

For Tank 1014: Enbridge will retain a consultant to assess the integrity of the ringwall and the effect the integrity of the ringwall has on the tank. If there is an integrity concern associated with the ringwall, the consultant will provide a recommendation for the appropriate repair for this ringwall. Additionally, an assessment will be made to determine proper site drainage. Estimated timeframe for completing these assessments is by the third quarter of this year.

For Tank 1015: This tank has been demolished and no further action is needed.

For Tank 1016: This tank is currently out of service and in the process of being demolished, no further action is needed.

For Tank 1153: This tank is currently out of service undergoing an API 653 internal inspection. Corrective actions will be determined once the inspection report has been received.

For Tank 1154: Similar to Tank 1014, Enbridge will retain a consultant to assess the integrity of the ringwall and the effect the integrity of the ringwall has on the tank. If there is an integrity concern associated with the ringwall, the consultant will provide a recommendation for the appropriate repair for this ringwall. Additionally, an assessment will be made to determine proper site drainage. Estimated timeframe for completing these assessments is by the third quarter of this year.

PHMSA Finding

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

Enbridge did not perform the monthly inspection 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.

<u>Enbridge Response</u>

Enbridge utilizes Maximo for inspection scheduling and documentation. Enbridge Cushing Terminal Operations Technicians performed the monthly tank inspections as required by 49 CRF 195 and API 653. The Technicians however, did not always enter the data into Maximo during the month in which the inspections were performed. The information regarding some inspections was logged into Maximo during the month following the inspection activity. When this occurred, the employee did not change the default date in Maximo. As a result, the date recorded in Maximo was the date of the data entry and not the inspection date. This then gives the false impression that the monthly tank inspections are not being performed within the required timeframes. To correct this clerical oversight, on May 23, 2012 Cushing region's Maximo Administrator issued a region-wide reminder to all Maximo users around this issue. Additionally, the Maximo Administrator conducted one-on-one training session with each Operations Technician concerning the tank inspection work orders. These one-on-one training sessions were completed June 2012. The email reminder and face-to-face sessions will ensure that future inspections will report the actual tank inspection date on the tank inspection work order within Maximo and prevent this issue from re-occurring.

<u>PHMSA Finding</u>

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 100 mV of polarization was achieved. Without instant off readings, the only check that can be made is *against the -850 mV with consideration of IR drop criterion (energized reading). Several of the energized readings taken using the profile tube did not meet the -850 mV criterion even before considering IR drop (20 feet, -625 mV, 25 feet, -607 mV, 30 feet, -684 mV, 40 feet, -702 mV).*

As another example, the records for tank #1295 do not show any depolarization measurements so one of the -850 mV criteria must be applied. Some of the structure-to-soil measurements did not meet either of the -850 mV criteria listed in NACE SP 0169 or API RP 651 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 Standard 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.

Enbridge Response

Enbridge has a corrective action plan (attached) in place that will enable us to successfully acquire 100mV polarization criterion or -850mV with consideration of IR drop. The plan requires the installation of coupons under the tanks to facilitate obtaining IR free readings (instant-off) as well as native potentials. Native potentials will enable the use of the 100mV shift criteria. Being able to obtain native potential and utilizing the instant-off potential will allow Enbridge to determine if the 100mv shift criteria have been met. It will also allow us to use the instant-off potentials in comparison to the -850mV baseline to determine if they are more electro-negative and thereby meeting the -850mV with consideration of IR drop criteria.

The corrective action plan was developed at the end of 2012 (prior to the receipt of this NOPV/Compliance Order) and finalized February 2013. The schedule and sequencing identified in the attached plan will be revised to indicate that tanks identified in the NOPV will be prioritized and completed as per the Compliance Order. We will then progress with remaining tanks in the Cushing Terminal with expected completion of the entire program targeted for end of 2014. The plan allows for effectively measuring pipe-to-soil potentials at the Cushing Terminal without interrupting all current sources within the potentially influenced area. For your reference, Tank 2212 was demolished in Q1 2012 and Tank 2211 is scheduled for demolition in Q4 2013.

PHMSA Finding

5. §195.581 Which 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.

§195.581 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.

Enbridge Response

Enbridge standard D04-102 4.3.1 states that the bottom four feet of the shell exterior shall be painted to protect the floor-to-shell "chime" weld and appurtenance area. This portion of the standard was included due to the area of the tank being defined as a critical zone due to the floor-to-shell "chime" weld and horizontal surfaces on the tank. It is not because Enbridge has had issues with this area of the tank with respect to tank shell corrosion. This area of the tank is most likely to be the wet zone, where water coming down the tank wall will splash up when it hits the ground and become stagnant on horizontal surfaces. This item was intended for those tanks that are not fully painted already. Enbridge respectfully disagrees with the statement that indicates painting the floor-to-shell "chime" weld and appurtenance area is confirmation that shell corrosion damage is occurring.

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 thickness 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 SP 0169 or API RP 651 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 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.*

Enbridge Response

1. See Enbridge response to NOPV Item Number 1.

2. See Enbridge response to NOPV Item Number 4.

3. See Enbridge response to NOPV Item Number 1.

4. Enbridge will gather and provide requested cost information.

Enbridge would appreciate your consideration of the additional information provided and proposed measures in this matter. Should you have any questions or require further information, please contact me at (218) 464-5740.

Respectfully,

Shaun Kavajecz
Sr. Manager, US Pipeline Compliance