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ROONEY RIPPIE & RATNASWAMY LLP

Kingsbury Center, Suite 600, 350 W. Hubbard St., Chicago, IL 60654 | P. 312-447-2800 | F. 312-447-2899 | www.r3law.com

Darren J. Hunter
(312) 447-2818
darren.hunter@r3law.com

November 6, 2015

Via Federal Express

Jeffrey D. Wiese
Associate Administrator
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Avenue, SE
East Building, 2nd Floor
Washington, DC 20590

Re: CPF No. 4-2013-5004
Enbridge Pipelines (Ozark) L.L.C.'s Petition for Reconsideration

Dear Mr. Wiese,

On behalf of Enbridge Pipelines (Ozark) L.L.C., we file an original and three copies of its Petition for Reconsideration and Brief in Support with regard to Item 1 of the Final Order in the above-referenced matter. Enbridge does not seek reconsideration of Items 2 through 5 of the Final Order. Please return a file-stamped copy in the enclosed self-addressed, stamped envelope.

Should you have any questions or require any additional information, please do not hesitate to contact me.

Sincerely,

Darren J. Hunter

cc: phmsachiefcounsel@dot.gov (with enclosure)

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the matter of:	)	
	)	
Enbridge Pipelines (Ozark) L.L.C.,	)	CPF No. 4-2013-5004
	)	
Respondent.	)	
	)	

PETITION FOR RECONSIDERATION
AND
BRIEF IN SUPPORT

Respondent Enbridge Pipelines (Ozark) L.L.C. ("Respondent"), through its counsel, Rooney Rippie & Ratnaswamy LLP, submits its Petition for Reconsideration and Brief in Support pursuant to 49 C.F.R. § 190.243.

By letter dated October 16, 2015, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") transmitted to Respondent a Final Order dated October 16, 2015, in the matter of CPF No. 4-2013-5004 (the "Final Order"), which was received by Respondent on October 19, 2015. This Petition for Reconsideration seeks reconsideration by the Associate Administrator for Pipeline Safety of Item 1 of the Final Order, including the Finding of Violation of 49 C.F.R. § 195.432(b), Assessment of Penalty and Compliance Order, on the grounds stated herein.

Respondent does not seek reconsideration regarding Items 2 through 5 of the Final Order, and we have paid the Assessment of Penalty regarding Item 4.

PROCEDURAL BACKGROUND

1. Following an inspection of Respondent's Cushing Terminal in Cushing, Oklahoma in November 2011, PHMSA transmitted to Respondent a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order dated March 3, 2013 (the "NOPV"). Regarding Item 1, the NOPV alleged that Respondent violated 49 C.F.R. § 195.432(b), by failing to conduct external inspections of certain in-service breakout tanks consistent with American Petroleum Institute ("API") Standard 653, which is incorporated by reference in 49 C.F.R. §§ 195.3 and 195.432. Specifically, the NOPV alleged that Respondent did not determine the shell corrosion rates used to establish proper external inspection intervals consistent with section 6.3.2.1 of API Standard 653. The NOPV proposed a civil penalty in the amount of $33,700 for Item 1, and also proposed to order Respondent to comply with the regulatory provisions that served as the basis of the alleged violation. The NOPV is attached hereto as Exhibit A.

2. Respondent responded to the NOPV by letter dated April 26, 2013 (the "Response"). In the Response, Respondent explained that it operated in compliance with 49 C.F.R. § 195.432 and API Standard 653. The Response is attached hereto as Exhibit B.

STANDARD FOR PETITION FOR RECONSIDERATION

3. The standard for a Petition for Reconsideration is set forth in 49 C.F.R. § 190.243, which provides that a Respondent may petition the Associate Administrator for reconsideration of a Final Order. Respondent meets the requirements to seek reconsideration of Item 1 of the Final Order.

4. As set forth in more detail in the Legal Discussion, Respondent complied with 49 C.F.R. § 195.432(b) and API Standard 653 regarding external inspection intervals of certain breakout tanks at Cushing Terminal. Consistent with § 190.243(a), Respondent respectfully avers that PHMSA's interpretation of API Standard 653 is contrary to the intent of the standard, contrary to industry practice, and will set an infeasible precedent regarding external inspection intervals of breakout tanks. Respondent respectfully believes that PHMSA's interpretation of API 653 will have unintended and negative consequences. For these reasons, the effectiveness of Item 1 of the Final Order should be stayed.

5. Consistent with § 190.243(b), Respondent states that it will raise additional facts and arguments in the Legal Discussion, including offering two separate opinions from industry experts related to external inspection methodology under API Standard 653. Respondent did not raise those facts and arguments in the original response to the NOPV because Respondent did not anticipate PHMSA's interpretation of the methodology to calculate external inspection intervals, and specifically did not anticipate the far-reaching consequences of PHMSA's interpretation.

6. Respondent will not raise repetitious information or arguments, but will clarify its previously stated position. Respondent concedes that certain language used in its original response was not artfully drafted and, therefore, is concerned that PHMSA may have misinterpreted its meaning and intent. Specifically, Respondent stated in its original response that it is feasible to have a "measurement result in 'negative corrosion growth' which would indicate that the corrosion growth rate is negligible." Exhibit B at 2. Respondent never meant to imply that the shell plate increased in thickness over time. Respondent will further clarify that statement in the Legal Discussion.

7. Consistent with § 190.243(c), Respondent recognizes that the filing of a Petition for Reconsideration stays the payment of the civil penalty, but does not stay compliance with the Compliance Order. Respondent will submit its shell-thickness measurement procedure within thirty (30) days of the Final Order. The other compliance requirements related to Item 1 are long-term actions, and Respondent hopes to resolve this Petition before the deadlines to complete those actions. In the interim, Respondent requests the Associate Administrator to grant a stay.

8. Finally, consistent with § 190.243(d), Respondent will provide any additional information that the Associate Administrator may require to resolve this Petition for Reconsideration.

LEGAL DISCUSSION

9. The legal issue is straightforward. Pursuant to 49 C.F.R. § 190.432(b), operators are required to inspect the physical integrity of each breakout tank consistent with the requirements of API Standard 653. Section 6 of API Standard 653 sets forth the inspection requirements, subsection 6.3 sets forth the external tank inspection requirements, and subsection 6.3.2.1 sets forth the required intervals to conduct external tank inspections. According to subsection 6.3.2.1, operators must conduct external inspections of breakout tanks at least every 5 years or *RCA*/4*N* years, whichever is less. Under this formula, *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.

10. During the inspection, PHMSA believed that Respondent failed to apply this formula correctly. Specifically, PHMSA believed that Respondent failed to incorporate the correct shell corrosion rate (*N*) into the formula, because Respondent did not measure the shell corrosion rate (*N*) at the exact same spot on the subject tanks based on prior measurements. Therefore, PHMSA asserted that Respondent was in violation of subsection 6.3.2.1 of API Standard 653.

11. Respondent concedes that it did not measure the shell corrosion rate at the exact same location on the subject tanks, but states that API Standard 653 does not require that such measurements be taken at the exact same location. Respondent states that it applied the formula exactly as required by the API standard. Thus, the single legal issue in this Petition for Reconsideration is whether Respondent applied the formula consistent with the requirements of API Standard 653.

12. In support of PHMSA's position that Respondent failed to measure the shell corrosion rate correctly, PHMSA noted that the shell corrosion rates for three tanks (#1014, #2228, and #3011) were negative, which implied that the shell plate "increased" in thickness over time. Because it is not possible for a shell plate to "increase" in thickness over time, PHMSA concluded that Respondent applied the incorrect methodology in measuring the shell corrosion rate.

13. In its response to the NOPV, Respondent acknowledged that it did not measure the shell corrosion rate at the exact same spot on the subject tanks. However, Respondent stated that it followed industry practice and the dictates of API Standard 653 in how it took those measurements. Respondent explained that there are variables that affect the calculation, and therefore it is possible to have a measurement result in "negative corrosion growth."

14. In retrospect, Respondent did not provide a sufficiently detailed explanation of the measurement methodology and how the formula should be applied. To be clear, whenever a measurement results in "negative corrosion growth," it simply means that there was either no corrosion or non-material corrosion (within tolerance levels) over the time period at issue. "Negative corrosion growth" does not imply that the shell plate increased in thickness over time. Because there was no corrosion over the time period at issue, the 5-year interval for Respondent to conduct external inspections of the breakout tanks applied.

15. Given the short period of time that PHMSA allows to file a Petition for Reconsideration, Respondent sought the opinions of two subject matter experts to shed light on the measurement methodology under API Standard 653 and industry practices. Both subject matter experts are Professional Engineers, API Authorized Inspectors, and members of the API Committee on Aboveground Storage Tanks.

16. First, John M. Lieb, P.E., the Chief Engineer at Tank Industry Consultants ("TIC"), signed an Affidavit in which he attached and referenced his Curriculum Vitae and Report. Mr. Lieb's Affidavit is attached as Exhibit C, his Curriculum Vitae as Exhibit C-1, and his Report as Exhibit C-2. If called to testify, Mr. Lieb would testify to the issues and opinions stated in those exhibits. In his Report, Mr. Lieb states unequivocally that API Standard 653 does not require operators to measure corrosion growth rates at the exact same locations on the tanks. Mr. Lieb offers the following opinions:

a. Subsection 6.3.3.1 of API Standard 653 provides that: "External ultrasound thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can be an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator." Mr. Lieb emphasized that nowhere in API Standard 653 does it require the operator to measure corrosion rate at the same location on the tank.

b. A tank operator may elect to take measurements at random locations on the tank to determine general corrosion rates and still be in compliance with the letter and intent of API Standard 653. Indeed, in Mr. Lieb's experience, that is the more common method to determine corrosion rates.

c. There are numerous practical limitations in measuring tank thickness at the exact same location on the tank.

d. The determination of uniform general corrosion is based on a statistically valid random sample of measurements. Therefore, there is no technical advantage in duplicating the measurements at the exact same location.

e. Furthermore, in many cases, tank design and construction documentation are not available, so there are no records to establish the baseline thickness. In such cases, it is common practice to take representative thickness measurements of the shell plates to establish the baseline.

f. It is not uncommon to see "negative corrosion growth" with thickness measurement surveys. Mr. Lieb explained that that generally occurs when the tank has not experienced any general uniform metal loss due to corrosion from one time period to the next. Mr. Lieb cited numerous reasons why an operator may see "negative corrosion growth," and that is not reflective that the measurement methodology or application of the formula was incorrect.

g. Respondent's methodology in taking the measurements is consistent with sound engineering principles and the provisions of API Standard 653.

17. Second, Steve Caruthers, P.E., a Professional Engineer and Authorized Inspector at Tank Consultants, Inc. ("TCI"), signed an Affidavit in which he attached and referenced his Curriculum Vitae and Report. Mr. Caruther's Affidavit is attached as Exhibit D, his Curriculum Vitae as Exhibit D-1, and his Report as Exhibit D-2. If called to testify, Mr. Caruthers would testify to the issues and opinions stated in those exhibits. In his Report, Mr. Caruthers states unequivocally that API Standard 653 does not require operators to measure corrosion growth rates at the exact same locations on the tanks. Mr. Caruthers offers the following opinions:

a. Subsection 6.3.3.1 of API Standard 653 gives the discretion to the operator to determine the extent of thickness measurements.

b. The predominant practice in the industry is to take ultrasonic measurements of shell thickness with a straight beam ultrasonic instrument that measures a small spot on the shell approximately 0.125" in diameter to determine general corrosion rates. Mr. Caruthers explained that general corrosion occurs over large areas and the exact spot of measurement will not affect the thickness measured.

c. Mr. Caruthers has been responsible for the inspection and evaluation of thousands of aboveground tanks for oil companies throughout the United States. He stated that virtually all tank operators use ultrasonic thickness readings for in-service tank inspections performed under API Standard 653. He added that very few attempt to identify the exact spot of the previous measurement, because the goal under API Standard 653 is to identify general corrosion, not spot corrosion.

d. It is not uncommon to find shell thickness measurements for in-service inspections to be larger than previous measurements. When thickness readings are encountered that are larger than previous measurements (i.e., negative corrosion growth), the difference is due to mill tolerances. Mr. Caruthers explained that plate materials that are not corroded have varying thicknesses, and each steel specification has a tolerance for plate thickness to be under and over the specified thickness. In these cases, the inspection interval is set at 5 years.

e. Respondent's methodology in taking measurements meets the intent of API Standard 653 and is consistent with best industry practices.

18. From a legal perspective, Respondent is required to comply with 49 C.F.R. § 195.432(b), which in turn requires Respondent to comply with the inspection requirements of API Standard 653. Therefore, Respondent is required to comply with API Standard 653. For the reasons stated by Mr. Lieb and Mr. Caruthers, Respondent complied with the standard.

19. PHMSA has the burden of proof. In this case, to reach the conclusion that Respondent violated 49 C.F.R. § 195.432(b), PHMSA expanded scope of API Standard 653 to require an operator to take the measurements at the exact same locations as the previous measurements. However, API Standard 653 does not require that measurements be taken at the same spot. In PHMSA's rules, PHMSA did not change the measurement methodologies set forth in API Standard 653. Therefore, PHMSA must apply API Standard 653 as it is written. PHMSA

cannot expand the scope of API Standard 653 in the context of a Final Order. The only way PHMSA can expand the scope of API Standard 653 is through the rulemaking process.

20. Furthermore, PHMSA's interpretation of API Standard 653 is counter to industry practices. Thus, if PHMSA's interpretation is permitted to stand, PHMSA's Final Order will not only impact Respondent, it will have a profound impact on the industry as a whole. Both Mr. Lieb and Mr. Caruthers are members of the API Committee on Aboveground Storage Tanks and both have conducted numerous external tank inspections for companies in the oil industry. They both stated that they do not take measurements at the same location as the previous measurement, and both explained that the purpose of API standard 653 is to identify general corrosion, not spot corrosion. They also both stated that there is no advantage to identifying corrosion at the exact same location and, in fact, it is problematic to do so. In summation, Mr. Lieb and Mr. Caruthers both stated that Respondent followed industry practice. Thus, PHSMA's interpretation will have far-reaching consequences on industry.

21. To the extent PHSMA has any doubts or questions regarding the correct measurement methodology under API Standard 653, and given the importance of this issue, Respondent is willing to offer supplemental evidence in further support its position.

CONCLUSION

22. For the foregoing reasons, Respondent Enbridge Pipelines (Ozark) L.L.C. respectfully requests that the Associate Administrator grant its Petition for Reconsideration of Item 1 of the Final Order.

November 6, 2015

Respectfully Submitted,
Counsel for Enbridge Pipelines (Ozark) L.L.C.

Darren J. Hunter
Rooney Rippie & Ratnaswamy LLP
350 W. Hubbard, Suite 600
Chicago, Illinois 60654
(312) 447-2818 – Telephone
(312) 447-2899 – Facsimile
darren.hunter@r3law.com

Cc: phmsachiefcounsel@dot.gov

Exhibits

Exhibit A

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue SE
Washington, DC 20590

OCT 16 2015

Mr. Mark Maki
President
Enbridge Pipelines (Ozark), LLC
1100 Louisiana Street
Suite 3300
Houston, TX 77002

Re: CPF No. 4-2013-5004

Dear Mr. Maki:

Enclosed please find the Final Order issued in the above-referenced case. It makes findings of violation, assesses a civil penalty of $78,700, and specifies actions that need to be taken by Enbridge Pipelines (Ozark), LLC, to comply with the pipeline safety regulations. The penalty payment terms are set forth in the Final Order. When the civil penalty has been paid and the terms of the compliance order completed, as determined by the Director, Southwest Region, this enforcement action will be closed. Service of the Final Order by certified mail is deemed effective upon the date of mailing, or as otherwise provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

for Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Rodrick Seeley, Regional Director, Southwest Region, OPS
Mr. Shaun Kavajecz, Senior Manager, US Pipeline Compliance, Enbridge Energy Company, Inc. 26 E. Superior Street, Suite 309 Duluth, MN 55811

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	)	
	)	
Enbridge Pipelines (Ozark), LLC,	)	
a subsidiary of Enbridge, Inc.,	)	**CPF No. 4-2013-5004**
	)	
Respondent.	)	

FINAL ORDER

During November 2011, 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 Enbridge Pipelines (Ozark), LLC (Enbridge or Respondent), at the company's Cushing Terminal in Cushing, Oklahoma. Enbridge is a subsidiary of Enbridge, Inc., an international energy company involved in the generation, transport, storage and distribution of oil, gas and electricity assets, with its corporate headquarters in Calgary, Canada, and a United States headquarters in Houston, Texas.[1]

As a result of the inspection, the Director, Southwest Region, OPS (Director), issued to Respondent, by letter dated March 3, 2013, 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 Enbridge had committed various violations of 49 C.F.R. Part 195 and proposed assessing a civil penalty of $78,700 for the alleged violations. The Notice also proposed ordering Respondent to take certain measures to correct the alleged violations. The warning items required no further action, but warned the operator to correct the probable violation or face future potential enforcement action.

Enbridge responded to the Notice by letter dated April 26, 2013 (Response). The company contested certain elements of the allegations of violation and provided information concerning the corrective actions it had taken. Respondent did not request a hearing and therefore has waived its right to one.

FINDINGS OF VIOLATION

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

[1] See www.enbridge.com. Current as of January 3, 2015.

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

> **§ 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).

The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b) by failing to properly inspect the physical integrity of several in-service breakout tanks at its Cushing, Oklahoma facility, in accordance with American Petroleum Institute (API) Standard 653.[2] Specifically, the Notice alleged that Enbridge failed to properly determine the shell corrosion rates used to establish proper external inspection intervals under subsection 6.3.2.1 of that standard.[3]

According to the Notice, a critical element in the formula set forth in subsection 6.3.2.1 and used to calculate a shell inspection interval less than the five-year maximum is N, the shell corrosion rate. PHMSA alleged that this variable in the formula should be calculated by dividing the measured metal loss by the time over which it occurred. Metal loss, in turn, is determined by subtracting a more recent shell thickness measurement from one made earlier in time at the same location on the breakout tank. The change in shell thickness would then be divided by the time interval between measurements to determine a corrosion rate. PHMSA asserted that since some of Enbridge's metal loss calculations were negative, such a result would mean that the shell plate had actually *increased* in thickness over time. PHMSA alleged that this result indicated the methodology used by Enbridge was flawed and inconsistent with API Standard 653.

In its Response, Enbridge argued that it had followed "industry-accepted" inspection practices and that the corrosion growth-rate calculation it had used was the same as that set out in API Standard 653 and was "used industry-wide." The company explained that when determining the proper inspection intervals, it had compared shell-plate thickness measurements taken at different locations, instead of multiple measurements taken at the same location. Enbridge

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[2] API Standard 653, "Tank Inspection Repair, Alteration, and Reconstruction" (3rd edition, December 2001, which includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008) and errata (April 2008)), has been incorporated by reference into 49 C.F.R. Part 195 under 49 C.F.R. § 195.3.

[3] API Standard 653, subsection 6.3.2.1, states:

> "**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 five 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."

argued that there are many variables that can affect these calculations, such as steel tolerances, measurement differentials, and differing rates of corrosion across various portions of the tanks that might have resulted in what the company reported as "negative corrosion growth." Enbridge argued that such a result merely indicated that the corrosion growth rate was "negligible."[4]

I find Enbridge's argument unpersuasive. Considering any possible tolerance variables, it is only feasible for Enbridge's methodology to be effective in the unlikely event that corrosion rates were completely uniform across the tanks, but the actual measurements taken by Enbridge show that the corrosion rates were not, in fact, uniform. It is clear that the "negative growth rate" used by Enbridge is inconsistent with the company's own measurements and is most likely the result of a flawed methodology in calculating corrosion growth rate under API Standard 653. While Enbridge may have intended to apply API 653 properly, the company failed to properly determine the corrosion growth rate in accordance with sound engineering principles.

Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. § 195.432(b) by failing to properly inspect the physical integrity of several of its in-service breakout tanks at the Cushing, Oklahoma facility in accordance with API Standard 653.

Item 4: The Notice alleged that Respondent violated 49 C.F.R. §§ 195.565 and 195.571, which state:

> **§ 195.565 How do I install cathodic protection in breakout tanks?**
> After October 2, 2000, when you install cathodic protection under § 195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels ($79.5m^3$) 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 § 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).

The Notice alleged that Respondent violated 49 C.F.R. §§ 195.565 and 195.571 by failing to meet at least one of the applicable criteria for cathodic protection on several Cushing Terminal breakout tanks, as required by API Recommended Practice 651 and NACE SP 0169.

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[4] Response, at 2.

Specifically, the Notice alleged that Enbridge used the 100 mV polarization criterion on a portion of the breakout tanks and the -850 mV with consideration of IR drop on others. According to PHMSA, its inspector had 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, the Notice alleged that Respondent operated multiple tanks (#1153, #1295, #2211, #1182, #2218, #1320, #2212, #2215 and #2223) that did not comply with one of the established cathodic protection compliance criteria.

In its Response, Enbridge did not contest the allegations and noted that it had begun a corrective action plan at the end of 2012 to enable it to successfully acquire 100 mV polarization criterion or -850 mV with consideration of IR drop. In addition, one of the non-compliant tanks was demolished during the first quarter of 2012 and a second was scheduled for demolition in the fourth quarter of 2013.[5] PHMSA commends Respondent's efforts to ensure future compliance, but would note that past non-compliance is not excused as a result.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. §§ 195.565 and 195.571 by failing to meet at least one of the applicable criteria for cathodic protection on several of its Cushing Terminal breakout tanks as required by API Recommended Practice 651 and NACE SP 0169.

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 $100,000 per violation for each day of the violation, up to a maximum of $1,000,000 for any related series of violations.[6] 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; the Respondent's ability to pay the penalty 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 $78,700 for the violations cited above.

Item 1: The Notice proposed a civil penalty of $33,700 for Respondent's violation of 49 C.F.R. § 195.432(b), for failing to properly determine shell corrosion rates necessary to establish external inspection intervals in accordance with API Standard 653. Respondent's method of

[5] Response, at 6.

[6] The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. No. 112-90, § 2(a)(1), 125 Stat. 1904, January 3, 2012, increased the civil penalty liability for violating a pipeline safety standard to $200,000 per violation for each day of the violation, up to a maximum of $2,000,000 for any related series of violations.

measuring thickness resulted in inconsistent and unhelpful results, and as a result, Enbridge lacked accurate data on the shell thickness of several breakout tanks at the company's Cushing Terminal for years. This resulted in reduced safety and an elevated risk of failure because of an ineffective safety-inspection protocol. Enbridge has not presented any evidence or argument that would justify a reduction in the proposed penalty. Accordingly, having reviewed the record and considered the seriousness of the offense and assessment criteria, I assess Respondent a civil penalty of $33,700 for violation of 49 C.F.R. § 195.432(b).

Item 4: The Notice proposed a civil penalty of $45,000 for Respondent's violation of 49 C.F.R. §§ 195.565 and 195.571, for failing to meet at least one of the applicable criteria for cathodic protection on some Cushing Terminal breakout tanks, in accordance with API Recommended Practice 651 and NACE SP 0169. Enbridge neither contested the allegation of violation nor offered any reason for its non-compliance. The failure to maintain proper cathodic protection for the company's breakouts tanks could have led to a failure at a major terminal, where safety violations pose a higher level of risk. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $45,000 for violation of 49 C.F.R. §§ 195.565 and 195.571.

In summary, having reviewed the record and considered the assessment criteria for each of the Items cited above, I assess Respondent a total civil penalty of **$78,700.**

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, Mike Monroney Aeronautical Center, P.O. Box 269039, Oklahoma City, Oklahoma 73125. The Financial Operations Division telephone number is (405) 954-8845.

Failure to pay the $78,700 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 Items 1 and 4 in the Notice for violations of 49 C.F.R. §§ 195.432(b), and 195.565 and 195.571, respectively. 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. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to the violation of § 195.432(b) **(Item 1)**, Respondent must modify its breakout tank inspection program to correctly determine the shell corrosion rates by correctly calculating the shell thickness and corrosion rates on all of the breakout tanks in the Cushing Terminal and re-determining the external inspection intervals for each breakout tank.

2. With respect to the violation of §§ 195.565 and 195.571 **(Item 4)**, Respondent must take appropriate action 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 RP651 have been achieved.

3. With respect to the violation of § 195.432(b) **(Item 1)**, Respondent must submit, for PHMSA approval, a shell-thickness measurement procedure within 30 days of receipt of this Order. Enbridge 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. Enbridge 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.

4. With respect to the violation of § 195.565 **(Item 4)**, Respondent must submit to PHMSA, a plan, with dates, to correct all cathodic protection deficiencies within 30 days of receipt of this Order. Enbridge must complete correction of all deficiencies within 12 months of receipt of this Order.

5. It is requested (not mandated) that Enbridge 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.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent and demonstrating good cause for an extension.

Failure to comply with this Order may result in the administrative assessment of civil penalties not to exceed $200,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

WARNING ITEMS

With respect to Items 2, 3 and 5, the Notice alleged probable violations of Part 195 but did not propose a civil penalty or compliance order for these items. Therefore, these are considered to be warning items. The warnings were for:

> 49 C.F.R. § 195.432(b) and (d) **(Items 2 and 3)** — Respondent's alleged failure to complete certain breakout tank repairs and to conduct required inspections necessary for safe operation or, in the alternative, provide engineering justification for not making such repairs; and
>
> 49 C.F.R. § 195.581 **(Item 5)** — Respondent's alleged failure to consistently apply coating material to all of its breakout tanks suitable to prevent atmospheric corrosion.

Enbridge presented information in its Response showing it had taken certain actions to address the cited items. If OPS finds a violation of any of these items in a subsequent inspection, Respondent may be subject to future enforcement action.

Under 49 C.F.R. § 190.243, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be sent to: Associate Administrator, Office of Pipeline Safety, PHMSA, 1200 New Jersey Avenue, SE, East Building, 2nd Floor, Washington, DC 20590, with a copy sent to the Office of Chief Counsel, PHMSA, at the same address. PHMSA will accept petitions received no later than 20 days after receipt of service of this Final Order by the Respondent, provided they contain a brief 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. Unless the Associate Administrator, upon request, grants a stay, all other terms and conditions of this Final Order are effective upon service in accordance with 49 C.F.R. § 190.5.

for: Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

OCT 16 2015
Date Issued

Payment Instructions

Civil Penalty Payments of Less Than $10,000

Payment of a civil penalty of less than $10,000 proposed or assessed, under Subpart B of Part 190 of the Pipeline Safety Regulations can be made by certified check, money order or wire transfer. Payment by certified check or money order (containing the CPF Number for this case) should be made payable to the "Department of Transportation" and should be sent to:

> Federal Aviation Administration
> Financial Operations Division (AMK-325)
> ATTN: Shelby Jones
> 6500 S MacArthur Blvd.,
> Oklahoma City, OK 79169

Wire transfer payments of less than $10,000 may be made through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfer should be directed to the Financial Operations Division at (405) 954-8845, or at the above address.

Civil Penalty Payments of $10,000 or more

Payment of a civil penalty of $10,000 or more proposed or assessed under Subpart B of Part 190 of the Pipeline Safety Regulations <u>must</u> be made wire transfer (49 C.F.R. § 89.21 (b)(3)), through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfers should be directed to the Financial Operations Division at (405) 954-8845, or at the above address.

INSTRUCTIONS FOR ELECTRONIC FUND TRANSFERS

(1) RECEIVER ABA NO. 021030004	(2) TYPE/SUB-TYPE (Provided by sending bank)
(3) SENDING BANK ABA NO. (Provided by sending bank)	(4) SENDING BANK REF NO. (Provided by sending bank)
(5) AMOUNT	(6) SENDING BANK NAME (Provided by sending bank)
(7) RECEIVER NAME TREAS NYC	(8) PRODUCT CODE (Normally CTR, or as provided by sending bank)
(9) BENEFICIAL (BNF) = AGENCY LOCATION CODE BNF = /ALC-69-14-0001	(10) REASONS FOR PAYMENT Example: PHMSA - CPF # / Ticket Number/Pipeline Assessment number

INSTRUCTIONS: You, as sender of the wire transfer, must provide the sending bank with the information for blocks (1), (5), (7), (9), and (10). The information provided in Blocks (1), (7), and (9) are constant and remain the same for all wire transfers to the Pipeline and Hazardous Materials Safety Administration, Department of Transportation.

Block #1 - RECEIVER ABA NO. - "021030004". Ensure the sending bank enters this 9-digit identification number; it represents the routing symbol for the U.S. Treasury at the Federal Reserve Bank in New York.

Block #5 - AMOUNT - You as the sender provide the amount of the transfer. Please be sure the transfer amount is punctuated with commas and a decimal point. **EXAMPLE: $10,000.00**

Block #7 - RECEIVER NAME - "TREAS NYC". Ensure the sending bank enters this abbreviation. It must be used for all wire transfers to the Treasury Department.

Block #9 - BENEFICIAL - AGENCY LOCATION CODE - "**BNF=/ALC-69-14-0001**". Ensure the sending bank enters this information. This is the Agency Location Code for the Pipeline and Hazardous Materials Safety Administration, Department of Transportation.

Block #10 - REASON FOR PAYMENT - "**AC-payment for PHMSA Case #** / To ensure your wire transfer is credited properly, enter the case number/ticket number or Pipeline Assessment number, and country."

NOTE: A wire transfer must comply with the format and instructions or the Department cannot accept the wire transfer. You as the sender can assist this process by notifying the Financial Operations Division (405) 954-8845 at the time you send the wire transfer.

Exhibit B

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

ENBRIDGE

April 26, 2013

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.

Enbridge Response

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.

PHMSA Finding

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.

<u>Enbridge Response</u>

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.

<u>PHMSA Finding</u>

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

Exhibit C

STATE OF ILLINOIS)
) ss.
COUNTY OF WILL)

I, John M. Lieb, being first duly sworn, declare under oath as follows:

1. That I am a Chief Engineer employed by Tank Industry Consultants, Inc. ("TIC").

2. That my background, experience and expertise, including my experience with regard to API Standard 653, is set forth in my Curriculum Vitae, a copy of which is attached hereto as Exhibit C-1 and incorporated herein by reference.

3. That Exhibit C-1 is true and correct and up-to-date copy of my Curriculum Vitae.

4. That I reviewed the Final Order issued by PHMSA on October 16, 2016 in matter CPF No. 4-2013-5004.

5. That based upon my review of the Final Order and based upon my background, experience and expertise in the oil industry and with regard to inspections of aboveground tanks, it is my opinion, within a reasonable degree of scientific and engineering certainty, that Enbridge operated in compliance with API Standard 653.

6. That I prepared a written report summarizing my opinions, a copy of which is attached hereto as Exhibit C-2 and incorporated herein by reference.

7. That Exhibit C-2 is a true and correct copy of my written report.

8. That all of my opinions in this Affidavit and in my written report are based on a reasonable degree of scientific and engineering certainty.

9. That if called to testify, I would testify as to the facts and opinions set forth in this Affidavit and Exhibits C-1 and C-2.

Further Affiant sayeth not.

John M. Lieb
John M. Lieb

Subscribed and sworn to before me
this 6th day of November, 2015

4-29-18
My commission expires:
Denise A Toman

"OFFICIAL SEAL"
Denise A. Toman
Notary Public, State of Illinois
My Commission Expires April 29, 2018

Exhibit C-1

John M. Lieb, P.E.
Chief Engineer
TANK INDUSTRY CONSULTANTS

CURRICULUM VITAE

Office Address

TANK INDUSTRY CONSULTANTS
24402 W. Lockport Street, Suite 223
Plainfield, Illinois 60544
815-556-8335 Office
E-Mail: lieb@tankindustry.com

Biographical Data

Birthdate:	January 11, 1951
Place of Birth:	Cleveland, Ohio
Citizenship:	United States

Education

Bachelor of Science, 1974, Cleveland State University
Specialization: Civil/Structural Engineering
Cooperative Education Program Diploma

American Institute of Chemical Engineers, March, 1983
Continuing Education Series, Storage and Flow of Solids

Various Continuing Education Courses

Honors and Awards

James F. Lincoln Arc Welding Foundation Award, 1974
API Resolution of Appreciation, 2006
API Resolution of Appreciation, 2007
API Recognition of 25 Years of Service, 2013

Work Experience

Tank Industry Consultants, Inc.
Chief Engineer
February 1, 1999 through present

Mr. Lieb is currently employed with TANK INDUSTRY CONSULTANTS, INC. (TIC) of Indianapolis, Indiana, one of the leading consulting engineering firms specializing in steel and concrete structures, as Chief Engineer. He is responsible for the contracting and execution of a wide range of professional engineering services for the industrial and municipal storage tank industries including:

- Tank Maintenance and Rehabilitation Engineering
- Tank Operating Consulting
- New Tank Specifications and Engineering
- Seismic Evaluation and Retrofit Design
- Assessment of Structural Systems
- Recommendations for Upgrading
- Risk-Based Assessment of Tanks
- Tank Troubleshooting
- API 653 Inspections
- Regulatory and Environmental Compliance
- Specialized Structural Engineering of
    - Plates and Shells
    - Buckling
    - Finite Element Analysis
    - Special Loads
- Modifications Required for Installation of Antennas and Other Appurtenances
- Fitness-for-Service and Change-of-Service Evaluations
- Condition Rating and Prioritization Services
- Floating Roof Tanks and Seals
- Leak Prevention and Secondary Containment Engineering
- Low Temperature and Cryogenic Storage
- Expert Witness and Dispute Resolution
- Training Seminars
- Failure Analysis

Chicago Bridge & Iron Company
Product Design Manager
June 24, 1974 through January 31, 1999

Mr. Lieb has over 24 years experience with Chicago Bridge & Iron Company (CBI) where he was Product Design Manager prior to joining TANK INDUSTRY CONSULTANTS, INC. Most of his experience has been in the design and detailing of complex ground level and elevated plate structures and their associated structural and mechanical systems. These structures have included:

- tanks certified to API 650 and API 620
- stamped and non-stamped ASME pressure vessels
- AWWA water storage tanks
- granular storage and handling systems
- a wide variety of plate structures and structural systems designed in accordance with various international codes and standards.

Mr. Lieb was previously a Product Design Manager in CBI's Plate Structures Engineering Group. In this capacity he was responsible for technical supervision and management of a group of graduate engineers and technicians performing contract and pre-contract design engineering for a wide variety of specialty plate structures for the petroleum, chemical, and granular industries. An important focus in this role was the development of cost-effective, reliable storage and process equipment design based on Customer specified performance requirements. He was also responsible for the preparation and maintenance of CBI Technical Standards related to these product lines. Mr. Lieb also served as CBI's representative to the American Petroleum Institute (API) and is active on the Subcommittee on Pressure Vessels and Tanks and several Special Task Forces. He continues to serve in this capacity for TANK INDUSTRY CONSULTANTS. Mr. Lieb is an ANSI/API 653 certified Aboveground Storage Tank Inspector.

Early in his career with CBI, Mr. Lieb served as a project engineer, design engineer and field engineer on numerous shop and field erected metal plate structures.

Cleveland, Ohio Veterans Administration Hospital
Engineering Draftsman and Technician
1972 through 1974

Mr. Lieb was an engineering draftsman and technician at the VA Hospital for a total of approximately 18 months during his participation in the Cooperative Education program at Cleveland State University.

Key Projects

The following is a list of representative projects Mr. Lieb has been involved in and his project responsibilities:

- Engineering Services Related to Pressure Relief Requirements
  Flint Hills Resources
  2014
  Chief Engineer

- Similar Service Assessment and Risk Based Inspection Programs
  Canal Terminal Company/North American Terminal Services
  2014
  Chief Engineer

- Engineering Services for an Emergency Tank Assessment and New Tank Construction
  Koch Nitrogen Company
  2013/2014
  Chief Engineer

- Review of Tank Design and Calculations for (2) 550,000 Barrel Tanks
  Enbridge Pipelines
  2013
  Chief Engineer

- Multiple Projects Concerning Review of Inspection Reports and Tank Evaluations for Koch Nitrogen Company
  2013
  Chief Engineer

- Engineering Review of Calculations and Design, Seven New Tanks Near Cold Lake, Alberta, Canada for Ganotec
  2013
  Chief Engineer

- Root Cause Failure
  Enbridge Energy
  2012
  Chief Engineer

- Seismic Evaluation of Tank at Kinder Morgan Westridge Terminal
  Golder Associates, Ltd.
  2012
  Chief Engineer

- Seismic Evaluation of 13 Tanks at Kinder Morgan Burnaby Terminal, Golder Associates, Ltd.
  2011
  Chief Engineer

- Engineering and Design Services for Iron Pellet Bin, Phoenix Fabricators & Erectors
  2011 and 2012
  Chief Engineer

- Risk-Based Inspection Program to Establish Out-of-Service Inspection Intervals, Enbridge Pipelines
  2011
  Chief Engineer

- Procedure Development for Floating Roof Tanks, Enbridge Pipelines
  2010
  Certified Inspector and Chief Engineer

- Peer Review of Structural Modifications to a Concrete Thermal Energy Storage Tank, NOVA Southeastern University
  2010
  Chief Engineer

- Wind and Storm Surge Analysis for External Floating Roof Tank
  2010
  Chief Engineer

- Deformation Analysis for Clarifier Tanks at Waste Water Treatment Plant (Bechtel)
  2009-2010
  Certified Inspector and Chief Engineer

- Review current editions of API Standard 653, API Recommended Practice 12R1, STI-SP001, EEMUA 159, UL-142 tank standard, and the pending USEPA SPCC Rules for inspection related issues (Chevron)
  2009
  Certified Inspector and Chief Engineer

- Allied Terminals
  Certified Inspector and Chief Engineer

- Engineering, Design and Testing
  Certified Inspector and Chief Engineer

- Fertilizer Guidelines Review, Koch Nitrogen Company
  2009

- Develop a Similar Service Assessment Program for a number of tanks,
  Enbridge Pipelines, Inc.
  2009

- Evaluate Alternative Methods for Seal Inspection on In-Service Tanks
  Pipeline Research Council International (PRCI)
  2008
  Certified Inspector and Chief Engineer
  Engineering Services Related to High Temperature and Other Tanks

- Flint Hills Resources, Various Locations
  2008
  Certified Inspector and Chief Engineer

- Development of Risk-Based Inspection Schedule for Ammonia Tanks
  Koch Nitrogen Company, Various Locations
  2008
  Certified Inspector and Chief Engineer

- Engineering Services Related to Various Cold Climate Tanks
  Enbridge Pipeline, Edmonton, Alberta, Canada
  2008
  Chief Engineer

- Design of External Floating Roof for 220' Diameter Tank
  James Machine Works for Valero, St. Charles, Louisiana
  2007
  Chief Engineer

- Engineering Inspection and Evaluation of Two Digester Gas Spheres
  City of Toledo, Toledo, Ohio
  2007
  Certified Inspector and Chief Engineer

- Design of External Floating Roof for 260' Diameter Tank
  PALA Interstate for Exxon, Baton Rouge, Louisiana
  2006
  Chief Engineer

- Engineering Services Related to Eight Stainless Steel Ethanol Tanks
  Cornhusker Energy, Lexington, Nebraska
  2005
  Chief Consulting Engineer

- Inspection and Evaluation Services for Various Floating Roof Tanks
  Terasen Pipe Line Company, Various Locations
  2004
  Certified Inspector and Chief Engineer

- Inspection, Evaluation and Rehabilitation Specifications for Refrigerated Ammonia Tanks
  Koch Nitrogen Company, Various Locations
  2004 thru 2008
  Certified Inspector and Chief Engineer

- Inspection and Evaluation Services for Various Petroleum Storage Tanks
  Enbridge Pipe Line Company, Various Locations
  Ongoing
  Certified Inspector and Chief Engineer

- Inspection, Evaluation and Rehabilitation Specifications for Various Wastewater Treatment Tanks
  General Motors Corporation, Various Locations
  2002
  Chief Engineer

- Inspect and Evaluate Fitness-for-Service of Miscellaneous Tanks
  Lone Star Alternate Fuels, Greencastle, Indiana
  2000-2001
  Certified Inspector and Chief Engineer

- Evaluate Fitness-for-Service of Hortonspheroids® and Spheres
  Phillips Pipeline Company, Various Locations
  2000-2001
  Chief Engineer

- Design of 30-inch Floating Suction Line
  Morse Construction Company, Everett, Washington
  2000-2001
  Chief Engineer

- Emissions Evaluation of Floating Roof Tanks
  Peoples Energy Resources Company, Joliet, Illinois
  2000
  Chief Engineer

- Design of Truck Loading Hoppers and Sludge Silos
  US Filter Company
  Jefferson County, Alabama
  2000
  Chief Engineer

- Evaluate Tornado Damaged Crude Oil Tank
  Sun Pipe Line Company, Clarkson, Kentucky
  2000
  Certified Inspector and Chief Engineer

- Inspect 6,000,000 Wet Seal Gas Holder
  Citizens Gas, Cincinnati, Ohio 2000
  Certified Inspector and Chief Engineer

- 2,000,000 Gallon Elevated Single Pedestal Water Tank
  City of Woodbridge, Virginia
  1999
  Engineer of Record

- (6) 55,000 Barrel Jet Fuel Storage Tanks
  Dulles Airport, Chantilly, Virginia
  1999
  Engineer of Record

- 15,000 Ton Alumina Silo
  Reynolds Metal Company
  Massena, New York
  1998
  Product Engineering Manager

- (2) 242,000 Barrel External Floating Roof Crude Oil Tanks
  Tosco Refining Company
  Trainer, Pennsylvania
  1997
  Engineer of Record

- 1000 Tonne Bauxite Ore Bin and Support Structure
  Alcoa of Australia
  Pinjarra, W. Australia
  1997
  Product Engineering Manager

- 1.8 Million Gallon Ellipsoidal Roof Standpipe
  Prince William County Service Authority
  Montclair, Virginia
  1986
  Engineer of Record

- Bottom Replacement in 40 ft Tank
  US Army Corps of Engineers, Peterson Air Force Base
  Colorado Springs, Colorado
  1995
  Engineer of Record

- Install New Dome Roof on Existing Tank
  Warminster Municipal Authority
  Warminster, Pennsylvania
  1995
  Engineer of Record

- 50 ft. Diameter Cone Roof Fire Water Tank
  Huntsman Chemical Corporation
  Belpre, Ohio
  1995
  Engineer of Record

- API Standard 653 Repairs to Foundation and Tank
  BP Oil
  Cleveland, Ohio
  1995
  Engineer of Record

- 3.88 Million Gallon Thermal Energy Storage Tank
  Ohio Edison for University of Akron
  Akron, Ohio
  1994
  Engineer of Record

- Miscellaneous Wastewater Treatment Tanks
  American Electric Power
  Cheshire, Ohio
  1993
  Engineer of Record

- (34) Various Petroleum Processing and Storage Tanks
  GATX Corporation
  Bedford Park, Illinois
  1993
  Engineer of Record

- 4,000,000 Gallon (Chilled Water) Thermal Energy Storage Tank
  State Farm Insurance Company
  Bloomington, Illinois
  1992
  Engineer of Record

- 10,000 Cubic Meter Wet Seal Gasholder
  AECI
  Modderfontein, South Africa
  1992
  Engineer of Record

- 45.5M Diameter Elevated Radial Cone Bottom Mud Thickener Tank
  Alcoa of Australia
  Wagerup, W. Australia
  1991
  Project Engineer

- Steam Plant Turbines and Piping Modernization
  Radford Army Ammunition Plant
  Radford, Virginia
  1991
  Engineer of Record

- Submarine Propulsion Noise Test System, Naval Underwater Systems Center
  Newport, Rhode Island
  1990
  Project Engineering Manager

- 1,000,000 Gallon Elevated Single Pedestal Water Tank
  City of Huron, Ohio
  1990
  Engineer of Record

- Repair 200,000 Gallon Elevated Single Pedestal Tank
  Cedarville College
  Cedarville, Ohio
  1990
  Engineer of Record

- 60 ft Diameter Open Top Tank
  US Department of Energy
  Fernald, Ohio
  1989
  Engineer of Record

- J-6 Rocket Engine Test Facility, US Air Force
  Tullahoma, Tennessee
  1989
  Project Engineer (Pre-Contract Design Phase)

- 40,000 CF Wet Seal Gasholder
  ICI Americas
  Bayonne, New Jersey
  1988
  Project Engineer

- Fixed Digester Cover
  Colorado Metropolitan Waste Water Treatment District
  Security, Colorado
  1988
  Engineer of Record

- (6) ASME Section VIII Pressure Spheres Supported on Load Cells
  Dow Corning
  Carrollton, Kentucky
  1988
  Project Engineering Supervisor

- Analysis of Truss Bridge for Wastewater Tanks
  Denver Metropolitan Plant
  Denver, Colorado
  1987
  Engineer of Record

- Elevated Cone Bottom Sand Silo
  US Navy
  Guam, Marianas Islands
  1987
  Project Engineer and Engineer of Record

- 1,000,000 Gallon Elevated Fluted Column Water Tank
  City of Hopewell, Virginia
  1986
  Engineer of Record

- 75,000 Gallon Elevated Tripod Water Tank
  Pamplin City, Virginia
  1986
  Engineer of Record

- 1000 Ton Elevated Terephthalic Acid Crystal Silo
  Carolina Eastman Company
  1985
  Project Engineer

- J-Fuel Powdered Coal Storage Feasibility Study
  Hitachi-Zosen
  Tokyo, Japan
  1983
  Project Engineer

- 25,000 Ton Refined Sugar Silo
  American Crystal Sugar Company
  Crookston, Minnesota
  1983
  Project Design Engineer

- 10,000 Barrel/Day Shale Oil Retort Project
  Union Oil Company
  Parachute Creek, Colorado
  1981
  Project Engineering Supervisor

- (7) Double-Wall Gasifier Pressure Vessels
  Lurgi/American Natural Gas
  Beulah, North Dakota
  1980
  Project Engineering Supervisor

- Hortonspheroid® Inspection/Evaluation Program
  Sun Oil Company, Phillips Petroleum and Others
  Various Locations
  1978 through 1989
  Inspecting/Evaluating Engineer

- Das Island LNG/LPG Storage Project
  Abu Dhabi
  1984
  Project Design Engineer

- (9) Terephthalic Acid Crystal Elevated Cone Bottom Stainless Steel Tanks
  Amoco Chemical Corporation
  Berkeley County, South Carolina
  1974
  Project Design Engineer

Professional Activities

Registered Professional Engineer in the States of Texas, Ohio, Illinois, Colorado, Maryland, Nebraska, New York, Virginia, Pennsylvania, Florida, Louisiana, Michigan, Minnesota, Wisconsin, Wyoming, and the Provinces of Alberta, British Columbia, and Labrador and Newfoundland, Canada.

American Petroleum Institute (API)
Member of Subgroup Design - Subcommittee on Aboveground Storage Tanks and Special Task Forces, including API Standard 653 development. This Subcommittee maintains API Standards 650, 620, 653 and liaises with other subcommittees on related issues.

ANSI/API 653 Certified Aboveground Storage Tank Inspector
License # 51

STI SP001 Certification
ID # AC 21310

API RP 579 Fitness-for-Service
Completed API RP 579 Fitness-for-Service Training Course, March, 2000

ASCE – American Society of Civil Engineers
Member

Publications/Presentations

Mr. Lieb has authored several technical papers and publications on subjects related to the design, construction, operation, maintenance, inspection, and repair of liquid and granular storage systems and pressure vessels. A list of publications and presentations follows:

- ***Re-Rating Aboveground Storage Tanks***
  Port Technology International Magazine, Fifty-Eighth Edition
  Spring, 2013

- ***EFR-Tracker Floating Roof Monitoring System***
  Port Technology International Magazine, Fifty-Fifth Edition
  Summer, 2012

- ***API 653 Seminar***
  American Electric Power, July 2011

- ***New Technology for Floating Roofs: Sensor System for Monitoring of Floating Roofs in Petroleum Storage Tanks***
  Tank Storage Magazine, June, 2010

- ***Effective Above Ground Storage Tank Management Program***
  Port Technology International Magazine, Forty-Third Edition
  Autumn, 2009

- ***An Evaluation of Alternative Methods for Internal Floating Roof Seal Inspection for In-Service Tanks***
  National Institute for Storage Tank Management (NISTM)
  September 2008

- ***Floating Roof Design***
  Independent Liquid Terminals Assn (ILTA) Conference, June 2007

- ***Hydrostatic Test Exemption***
  2007 ThinkTanks Conference, February 2007

- ***Aboveground Storage Tank Settlement***
  2007 ThinkTanks Conference, February 2007

- ***Getting the Most Value From Your Ammonia Tank Inspection***
  2006 SynGas Conference, April 2006

- ***Similar Service Assessment***
  Hydrocarbon Processing Magazine, July 2007

- ***Floating Roof Penetration Cautions***
  National Institute for Storage Tank Management (NISTM), May 2005

- ***API 650 External Pressure Design Appendix***
  API Storage Tank Management and Technology Conference, November 2003

- ***Typical Tank Failures***
  Independent Liquid Terminals Association (ILTA) Conference, June 2003

- ***New API Pressure Testing Recommended Practice***
  National Institute for Storage Tank Management (NISTM), May 2002

- ***Recent Improvements in API Storage Tank Standards to Improve Spill Prevention and Leak Detection/Prevention***
  Freshwater Spills Symposium, March 2002

- ***API 653 Includes Fitness-For-Service Concepts of API RP 579***
  Independent Liquid Terminals Association (ILTA) Conference,
  June 2001

- ***Welding Research Council Bulletin 453, Minimum Weld Spacing Requirements for API Above Ground Storage Tanks***
  July 2000

- ***Temporary Construction Openings for Above Ground Storage Tanks***
  National Institute for Storage Tank Management Conference
  May 2000

- ***Proper Installation and Retrofitting of Double Bottoms***
  World Refining Magazine, September/October 2009

- ***API 653, Risk Based Assessment of Storage Tanks, Secondary Containment and Leak Detection, Advancements in Aboveground Storage Tank Management Seminar***
  Anchorage, Alaska, February 1999

- ***Aboveground Storage Tanks – not just a wide spot on the pipeline***
  Pipeline Magazine, August 1998

- ***Aboveground Storage Tank Services and Management Program***
  Course Developer and Instructor, Chicago Bridge & Iron Company
  June 1992

- ***Engineering Considerations in Retrofitting and Upgrading Aboveground Storage Tanks***
  Independent Liquid Terminals Association (ILTA) Conference
  June 1990

- ***A Tankbuilder's Perspective on Voluntary Standards Relating to Bulk Liquid Storage Tanks***
  ILTA Conference June 1989

Other Relevant Experience

Mr. Lieb has been personally responsible for the structural engineering design of more than 700 aboveground storage tanks and pressure vessels of all types, and has been involved in a review capacity in more than 1000 additional structures. He has personally inspected or evaluated the suitability for service of more than 500 tanks and vessels.

Exhibit C-2

TIC

TANK INDUSTRY CONSULTANTS

7740 West New York Street
Indianapolis, Indiana 46214
317 / 271-3100 - Phone
317 / 271-3300 – FAX

Plainfield, Illinois
815 / 556-8335

El Paso, Texas
915 / 790-0790

Houston, Texas
281 / 367-3511

Pittsburgh, Pennsylvania
412 / 262-1586

Sacramento, California
916 / 717-3608

November 4, 2015

David Stafford
Sr. Manager, US Pipeline Compliance
Enbridge
119 N. 25th Street East
Superior, WI 54880

Subject: TIC Review of Section 195.432 of
Pipeline and Hazardous Materials Safety Administration
Final Order Report of October 16, 2015
PHMSA CPF No. 4-2013-5004
TIC 15.267.I976.000

Mr. Stafford,

This letter report will summarize TIC's Mr. John M. Lieb's review of Section 195.432 of Pipeline and Hazardous Materials Safety Administration (PHMSA) "Final Order" Report of October 16, 2015. Mr. Lieb also reviewed Enbridge Energy's letter of April 26, 2013 to PHMSA to better understand the context of PHMSA's report of October 16th. Enbridge Energy's letter of April 26, 2013 was in response to PHMSA's "Notice of Probable Violation" (NOPV) dated March 4, 2013. Mr. Lieb did not review the original NOPV dated March 4, 2013 as referenced in the second paragraph of Enbridge Energy's April 26, 2013 letter.

The purpose of the review summarized in this letter report was to provide independent opinions with regard to a number of issues discussed in Section 195.432 of the PHMSA NOPV of March 4, 2013 and subsequent "Final Order" of October 16, 2015. The opinions expressed in this letter report are the opinions of John M. Lieb, P.E., and are based on Mr. Lieb's nearly 43 years of experience as an Engineer in the aboveground storage tank industry, including nearly 28 years as a member of the API Subcommittee on Aboveground Storage Tanks (SCAST). The opinions expressed herein are not to be construed as official interpretations of the American Petroleum Institute (API). The opinions expressed herein are limited to those issues discussed in Section 195.432, "Inspection of in-service breakout tanks" of the PHMSA reports.

BACKGROUND

The NOPV prepared by PHMSA and dated March 4, 2013 stated that *"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."

The "Final Order" prepared by PHMSA and dated October 16, 2015, stated that *"The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b) by failing to properly inspect the physical integrity of several in-service breakout tanks at its Cushing, Oklahoma facility, in accordance with American Petroleum Institute (API) Standard 653. Specifically, the Notice alleged that Enbridge failed to properly determine the shell corrosion rates used to establish proper external inspection intervals under subsection 6.3.2.1 of that standard.*

According to the Notice, a critical element in the formula set forth in subsection 6.3.2.1 and used to calculate a shell inspection interval less than the five-year maximum is N, the shell corrosion rate. PHMSA alleged that this variable in the formula should be calculated by dividing the measured metal loss by the time over which it occurred. Metal loss, in turn, is determined by subtracting a more recent shell thickness measurement from one made earlier in time at the same location on the breakout tank. The change in shell thickness would then be divided by the time interval between measurements to determine a corrosion rate. PHMSA asserted that since some of Enbridge's metal loss calculations were negative, such a result would mean that the shell plate had actually increased in thickness over time. PHMSA alleged that this result indicated the methodology used by Enbridge was flawed and inconsistent with API Standard 653.

In its Response, Enbridge argued that it had followed "industry-accepted" inspection practices and that the corrosion growth-rate calculation it had used was the same as that set out in API Standard 653 and was "used industry-wide." The company explained that when determining the proper inspection intervals, it had compared shell-plate thickness measurements taken at different locations, instead of multiple measurements taken at the same location. Enbridge argued that there are many variables that can affect these calculations, such as steel tolerances, measurement differentials, and differing rates of corrosion across various portions of the tanks that might have resulted in what the company reported as "negative corrosion growth." Enbridge argued that such a result merely indicated that the corrosion growth rate was "negligible."

I (PHMSA) *find Enbridge's argument unpersuasive. Considering any possible tolerance variables, it is only feasible for Enbridge's methodology to be effective in the unlikely event that corrosion rates were completely uniform across the tanks, but the actual measurements taken by Enbridge show that the corrosion rates were not, in fact, uniform. It is clear that the "negative growth rate" used by Enbridge is inconsistent with the company's own measurements and is most likely the result of a flawed methodology in calculating corrosion growth rate under API Standard 653. While Enbridge may have intended to apply API 653 properly, the company failed to properly determine the corrosion growth rate in accordance with sound engineering principles.*

Accordingly, based upon a review of all of the evidence, I (PHMSA) *find that Respondent violated 49 C.F.R. § 195.432(b) by failing to properly inspect the physical integrity of several of its in-service breakout tanks at the Cushing, Oklahoma facility in accordance with API Standard 653".*

DISCUSSION

Based on my review of the documents described above and my understanding of the facts in this matter, I did not conclude that Enbridge Energy failed to satisfy the provisions of API Standard 653 pertaining to corrosion rate and inspection interval calculations for its in-service breakout tanks at the Cushing, Oklahoma facility as alleged in the PHMSA NOPV and "Final Order". My opinions in this matter are based on the following considerations:

1) The PHMSA reports state that *"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."* API Standard 653 does not specify where thickness measurements are to be made to determine the rate of uniform general corrosion. In fact, API Standard 653 specifies in 6.3.3.1 that *"External ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator."* Therefore, while PHMSA's reference to the formula in 6.3.2.1 is correct, there is no requirement or recommendation in API Standard 653 that shell thickness measurements be taken at the same locations as previous measurements.
2) A tank owner/operator may elect to take shell thickness measurements at random locations that vary from previous locations to determine uniform general corrosion rates and still be in compliance with the letter and intent of API Standard 653. In my experience, performing thickness measurement surveys to establish uniform general corrosion rates are more commonly based on random measurement locations than on measurements repeated using the same locations as previous surveys. An exception to this practice is for insulated tanks where inspection openings in the insulation for the purpose of making shell thickness measurements are provided. In this case, dedicated insulation openings are used to minimize damage to the insulation system and to facilitate the thickness measurement process.
3) There are practical limitations in repeating the same exact thickness measurement locations from one thickness measurement survey to the next. For example, duplicating a measurement at the same location of a previous measurement requires either permanently marking the measurement locations on the tank, which can damage or compromise tank coatings; or by using a record document of previous measurement locations and careful measurements to duplicate the same locations for future measurements. The process is complicated when different inspection companies are involved from one survey to the next. Since the determination of uniform general corrosion is based on a statistically valid random sample of measurements, there is no technical advantage in exactly duplicating the previous measurement locations.
4) In many cases, especially for tanks constructed prior to the publication of API Standard 653 in 1991, tank design and construction documentation is not available. In cases where no "baseline" thickness measurement records exist for a tank, it is common practice to perform a thickness evaluation of the shell to establish baseline thicknesses to use for

establishing the uniform general corrosion rate. One common method is to take representative thickness measurements of the shell plates and then to establish the closest standard or "even gage" thickness to the measurements made for each shell course based on factors such as the age of the tank, the manufacturer, the materials in common use at the time of the tank construction and other factors. This method requires engineering judgment and should be done by an individual or company qualified in accordance with the provisions of API Standard 653. This method provides suitable baseline thickness data for establishing uniform general corrosion rates when properly performed. In cases where the original tank record drawings are available, the as-built thicknesses shown on the drawings are typically used as the baseline thicknesses for future measurement surveys. The assessment of uniform general corrosion rate must consider changes in tank service conditions, if any that may occur over the life of the tank. For example, the corrosion rate may change if the service of the tank is changed to a more corrosive one or to a less corrosive one. Such change of service conditions should be factored into the calculation of the inspection interval using the formula in 6.3.2.1.

5) Based on my understanding of the manner in which the baseline thicknesses for the shell were established for the subject tanks, the Enbridge methodology was consistent with sound engineering principles and the provisions of API Standard 653.
6) It is not uncommon to see apparent "negative corrosion growth" with thickness measurement surveys in my experience. This usually occurs in cases where the tank has not experienced any measurable uniform general metal loss due to corrosion from one time period to the next. Some of the conditions that can result in apparent "negative corrosion growth" are:
   a. Variation in as-built shell thickness due to mill tolerances on the supplied thickness. Mill tolerances on rolled steel plate may result in the actual as-built plate thickness being slightly more or less than the ordered plate thickness. Mill tolerances for steel plate manufactured in the United States are specified in American Society for Testing Standards (ASTM) specifications. For example, ASTM A480 would permit variations of 0.06 inches over-thickness and 0.01 inches under-thickness in the thickness of a rolled plate that is between 3/8-inch and 3/4-inch thick and between 84 inches and 120 inches wide. Note that this tolerance is measured along the longitudinal edges of the rolled plate. Thus for a plate ordered at 1/2-inch in thickness, the actual measured plate thickness may vary from 0.490 inches to 0.56 inches as a result of mill thickness tolerances alone.
   b. Variations in tank coating thickness. Making thickness measurements through the thickness of an applied coating or paint can affect the accuracy of steel plate thickness measurements. Accuracy of steel thickness measurements can be improved by removing the exterior coating to allow direct measurement of the steel thickness but this requires destruction of the paint or coating at the locations of the measurements and subsequent repair in most cases. The thickness of coating or paint can vary significantly even within a small area of the shell and can result in higher thickness measurements than previously measured in the same small area. Repainting a tank between one thickness measurement date and the next can affect the accuracy of thickness measurements.
   c. Number of significant figures reported in thickness measurements. The number of significant figures used in recording of thickness measurements varies among inspection companies in my experience. The most common practices in my

experience are to use either two or three significant figures in the decimal measurement using US Customary units, i.e., inches. Thus, a thickness survey using three figures following the decimal point may indicate an apparent gain (or loss) in thickness as compared to a thickness survey using only two figures following the decimal point.

d. Type and calibration of thickness measurement equipment. The accuracy of the thickness measurement survey is dependent on the capabilities and calibration of the equipment or devices used to measure thickness. Inadequate equipment or improper calibration can lead to inconsistencies in the thickness measurement data from one time to the next.

e. Human error. Occasionally, apparent "negative corrosion growth" can be attributed to simple human error, such as transposition of digits in recording thickness measurements. This type of error is usually identified by careful evaluation of the thickness measurement data in my experience.

7) Apparent "negative corrosion growth" is not necessarily an indication that the thickness measurement methodology or the use of the corrosion rate formula by Enbridge was faulty. As discussed above, there are many factors that can affect thickness measurement data. Apparent "negative corrosion growth" is common in tanks that have experienced no measurable or structurally significant general uniform metal loss.

SUMMARY

Based on my review of the documents provided to me and my understanding of the methodology Enbridge Energy utilized to establish baseline shell thicknesses and uniform general corrosion rates, I conclude that Enbridge Energy satisfied the provisions of API Standard 653 with respect to sections 6.3.2.1 and 6.3.3.1.

Please contact me at (815) 556-8335 (office) or Lieb@tankindustry.com if you have any questions.

Sincerely,

Tank Industry Consultants, Inc.

John M. Lieb

John M. Lieb, P.E.
Chief Engineer
API 653 Certified Inspector No. 051
STI Certified Inspector AC 21310

Cc: Stephen W. Meier, P.E., S.E. / Gregory R. "Chip" Stein, P.E. – TIC, Indianapolis
Sabrina Fleming – TIC, Plainfield

Exhibit D

STATE OF OKLAHOMA)
) ss.
COUNTY OF TULSA)

I, Steve Caruthers, being first duly sworn, declare under oath as follows:

1. That I am a Professional Engineer employed by Tank Consultants, Inc. ("TCI").

2. That my background, experience and expertise, including my experience with regard to API Standard 653, is set forth in my Curriculum Vitae, a copy of which is attached hereto as Exhibit D-1 and incorporated herein by reference.

3. That Exhibit D-1 is true and correct and up-to-date copy of my Curriculum Vitae.

4. That I reviewed the Final Order issued by PHMSA on October 16, 2016 in matter CPF No. 4-2013-5004.

5. That based upon my review of the Final Order and based upon my background, experience and expertise in the oil industry and with regard to inspections of aboveground tanks, it is my opinion, within a reasonable degree of scientific and engineering certainty, that Enbridge operated in compliance with API Standard 653.

6. That I prepared a written report summarizing my opinions, a copy of which is attached hereto as Exhibit D-2 and incorporated herein by reference.

7. That Exhibit D-2 is a true and correct copy of my written report.

8. That all of my opinions in this Affidavit and in my written report are based on a reasonable degree of scientific and engineering certainty.

9. That if called to testify, I would testify as to the facts and opinions set forth in this Affidavit and Exhibits D-1 and D-2.

Further Affiant sayeth not.

Steve Caruthers
Steve Caruthers

Subscribed and sworn to before me
this 6th day of November, 2015

Karen D Smith
My commission expires: 3-14-2018

KAREN D. SMITH
Notary Public in and for
STATE OF OKLAHOMA
Commission #02002420
Expires: March 14, 2018

Exhibit D-1

Education: B.S. Civil Engineering, Oklahoma University, 1974

Professional: Registered Professional Engineer, Oklahoma and Texas

API-653 Authorized Inspector Number 0154
American Welding Society Certified Welding Inspector 92120371, 19 yrs
Certified Tank Inspector, State of Pennsylvania
Member: API Committee on Refinery Equipment Subgroup Inspection
API-650 and 653 Standards

Work Experience:

35 years experience in above ground storage tank engineering, construction, maintenance, operation. Founder and President of TCI Services, Tulsa, OK.

22 years member of API Committee on Above Ground Storage Tanks, Subgroup Inspection. Authored many changes to the API standards for tanks including Standard 653, 650, and 620. Participated in task groups responsible for tank settlement measurement and evaluation, inspector qualifications for magnetic flux leakage inspection, repairs to tank bottom critical zone, alternatives for inspection of tank conditions not meeting current standards, and risk based inspection intervals.

Published Papers:

"Hydrotesting not required under new API-653 procedure (Fitness for Service)", Oil and Gas Journal, Jan. 31, 2000.

"Guidelines for Inspecting AST Internals", Oil and Gas Journal, July 8, 1996.

API-653 Appendix F

API-653 4.3.9.1 Weld Spacing Evaluation of Existing Tank Shell Weld Spaces on penetrations

API-653 4.4.5 Minimum Thickness for Tank Bottom Plates

API-650 Appendix T

Compensation: I will receive $300 per hour for work to write this report and any time required for deposition.

Litigation Experience in the last 4 years:

Civil Case No. 99/1996 Domino Oil, Inc. vs Phoenix Assurance Company of New York

Case No. CJ-2007-08167 Matrix v Tank Connection, et. Al.

CB&I v Lansing Asphalt Terminal Co. ("LATCO") et al

Marathon Petroleum Company LLC v Midwest Marine, Inc, et al, Civil Action No. 2:09cv-12804

Case No. 8:12-cv-959-T-33TBM, SATC v. Matrix Service, Inc.

Exhibit D-2

TCI Tank Consultants, Inc.

Nov. 3. 2015

David Stafford
Sr. Manager, US Pipeline Compliance
Enbridge
119 N. 25th Street East
Superior, WI 54880

Ref: PHMSA Shell Corrosion Growth Rate Assessment

Mr. Stafford

I have been asked to provide my opinion regarding a conclusion in CPF No. 4-2013-5004 written by the US DOT, Pipeline and Hazardous Materials Safety Administration. The conclusion to which I have been asked to give an opinion is on Page 3 of the Final Order. In summary, the document states that Enbridge failed to inspect the physical integrity of in-service breakout tanks at the Cushing, Oklahoma facility in accordance with API-653.

The background for this conclusion is that some thickness measurements of the vertical walls of some storage tanks were larger than previous measurements taken at routine inspections, resulting in negative corrosion rates.

API-653 Section 6.3.3.1 states "External, ultrasonic measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator."

The predominant practice throughout the tank maintenance industry is for ultrasonic measurement of shell thickness to be performed with a straight beam ultrasonic instrument that measures a small spot of the shell approximately 0.125" in diameter. As stated in Section 6.3.3.1, the purpose is to determine general corrosion rates. General corrosion occurs over large areas and the exact spot of measurement will not affect the thickness measured. Different measurements within any area of general corrosion will be very close to the same.

I have been responsible for the inspection and evaluation of thousands of above ground storage tanks throughout the United States and beyond for all major oil companies. All tank owners for which my company has worked utilize spot ultrasonic thickness readings for in-service API-653 inspections. Very few attempt to identify the exact spot of the thickness readings because the goal is to find general corrosion, not spot corrosion. Thickness measurements taken in different areas of a single plate will always be different if the plate is not corroded. When we encountered thickness readings larger than measured at previous inspections, we always considered the difference to be due to mill tolerances and set the inspection interval at 5 years.

Plate materials that are not corroded all have varying thickness. Each steel specification has a tolerance for plate thickness to be under and over the specified thickness. For example, the American Society for Testing and Materials (ASTM) specification for a common size of tank steel allows over thickness up to 0.100". This means a single plate just out of the mill can vary in thickness from one side to the other side from the specified thickness to the specified thickness plus 0.100".

In my experience of 41 years of inspecting and evaluating storage tanks to API standards, it is not uncommon to find shell thickness measurements for in-service inspections that are greater than in the previous inspection.

It is my opinion that the practice by Enbridge for taking shell thickness measurements and determining the inspection interval meets the intent of API-653 and is consistent with best industry practices.

I am a professional engineer with 35 years' experience in the design and inspection of above ground storage tanks. I am an API Authorized Inspector #0154 and a member of the API Committee for Aboveground Storage Tanks.

Sincerely,

Steve Caruthers

Steve Caruthers, P.E.

• 4333 W. 21st St. • Tulsa, Oklahoma 74107 • (918) 583) 3968 • FAX (918) 583-3966 • www.tank-consultants.com •
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