Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

January 18, 2016

Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
8701 South Gessner, Suite 1110
Houston, TX 77074

Attn: Mr. R. M. Seeley
Director, Southwest Region, PHMSA

Re: Notice of Probable Violation and Proposed Civil Penalty CPF 4-2015-5023
Enterprise Crude Pipeline LLC ("Enterprise")

Dear Mr. Seeley,

Enterprise is in receipt of the above referenced Notice of Probable Violation (NOPV) and Proposed Civil Penalty (PCP) dated October 14, 2015. On November 12, Enterprise requested an extension of 60 days to allow for additional time to review and submit our response. This letter serves as Enterprise's timely response to the five (5) Alleged Violations.

<u>Item 1:</u>

§195.430 Firefighting equipment.

Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be-
(c) Locate so that it is easily accessible during a fire.

EP Crude failed to have firefighting equipment located so that it is easily accessible at Wildfire Station #2. The station did not have the fire protection equipment (fire extinguisher) within the pump station fence perimeter. There was a fire extinguisher at the truck offloading area outside the fenced enclosure.

The EP Crude Procedure 1306 Fire Fighting Equipment states

> *"Firefighting equipment will be located at each pump station and breakout tank area for Company operated pipeline systems…*
>
> *The firefighting equipment must be in proper operating condition at all time, plainly marked as to its identify and the types of fires it is suited for. The equipment shall be located so that it is easily accessible in the event of a fire."*

After the inspection, EP Crude remediated the situation by installing an additional fire extinguisher located in the proximity of the booster pump and GASO Pump.

Enterprise Response to Item 1:

Enterprise installed an additional fire extinguisher within fenced enclosure in close proximity to the pumps in accordance with Enterprise's procedures.

Item 2:

§195.432 Inspection of in-service breakout tanks.

(b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, see § 195.3). However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).

EP Crude failed to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks by performing the routine monthly inspection as required by EP Crude Standard.9503 and API 653.

EP Crude Standard.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks sections 7.1 and 8.1 state,

*"**7.1 Periodic Monthly Inspections***
*Otherwise known as the "Monthly Visual Inspection" by industry, the external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This routine periodic in-service inspection shall include a visual inspection of the tank's exterior surfaces. The periodic Monthly visual inspection is intended for monitoring the external AST condition and its containment structure. The periodic Monthly visual inspection does **NOT** require a certified inspector.*

8.1 Periodic Monthly Inspections
The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month. The inspection checklist form is utilized in Appendix A, for periodic Monthly visual inspections."

API 653 Tank Inspection, Repair, Alteration, and Reconstruction section 6.3.1.1 states,

*"**6.3.1 Routine In-Service Inspections***

***6.3.1.1** The external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This inspection may be done by owner/operator personnel, and can be done by other than authorized inspectors as defined in 3.5. Personnel performing this inspection should be knowledgeable of the storage facility operations, the tank, and the characteristics of the product stored.*

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

6.3.1.3 *This routine in-service inspection shall include a visual inspection of the tank's exterior surfaces. Evidence of leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems, and appurtenances should be documented for follow-up action by an authorized inspector."*

EP Crude failed to perform the December 2013 monthly In-Service Breakout Tank inspections for Tanks #5610, #5611, #5617, #5618, #5650, #5653, & #5654.

Enterprise Response to Item 2:

Enterprise has updated the inspection database to include these required tank inspections.

Item 3:

§195.432 Inspection of in-service breakout tanks.

(b) Each operator must inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, see § 195.3). However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).

EP Crude failed to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks by performing the external inspection as required by EP Crude Standard.9503 and API 653.

EP Crude Standard.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks sections 7.2 and 8.2 state,

"7.2. External Inspection
All tanks shall be given a visual external inspection by an authorized inspector. Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof. Tanks may be in operation during this inspection. Documented external inspections are performed by an authorized API 653 inspector only.

8.2. External Inspection Frequency
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..."

API 653 Tank Inspection, Repair, Alteration, and Reconstruction section 6.3.1.1 states,

> *"**6.3.2 External Inspection***
>
> ***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."*

During the Headquarters office review of tank records, PHMSA Inspectors reviewed External Inspection records for several breakout tanks. It was noted that the inspections for Tank 1009 dated 5/10-11/2005 and 4/5/2012, had exceeded the 5 year interval required by API 653 sections 6.3.2.1.

<u>Enterprise Response to Item 3:</u>

Tank Integrity personnel will ensure that the External and UT inspections are performed in accordance with Enterprise's standards.

<u>Item 4:</u>

§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).

EP Crude failed to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks by performing the ultrasonic thickness inspection as required by EP Crude Standard.9503 and API 653.

EP Crude Standard.9503 Inspection and Testing of Atmospheric and Low-Pressure DOT Breakout Tanks sections 7.3 and 8.3 state,

> ***"7.3. Ultrasonic (UT) Thickness Inspection***
> *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...*
>
> ***8.3. Ultrasonic Thickness Inspection Frequency – UT***
> *When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following.*
>
> *(1) When the corrosion rate is **not known**, the maximum interval shall be five years. Corrosion rates may be estimated from tanks in*

similar service based on thickness measurements taken at an interval not exceeding five years. For additional details, contact the Enterprise Tank Integrity Supervisor.

*(2) When the corrosion rate is **known**, the maximum interval shall be the smaller of RCA/2N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) or 15 years."*

"6.3.3 Ultrasonic Thickness Inspection

***6.3.3.1** 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.*

***6.3.3.2** When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following:*

a. When the corrosion rate is not known, the maximum interval shall be 5 years. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding 5 years.

b. When the corrosion rate is known, the maximum interval shall be the smaller of RCA/2N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) or 15 years."

During the Headquarters office review of tank records, PHMSA Inspectors reviewed Ultrasonic Thickness inspection records for several breakout tanks. It was noted that the inspections for Tank 1009 dated 5/10-11/2005 and 4/5/2012, had exceeded the 5 year interval required by API 653 sections 6.3.3.2. The corrosion rate for the tank was unknown.

Enterprise Response to Item 4:

Tank Integrity personnel will ensure that the External and UT inspections are performed in accordance with Enterprise's standards.

Item 5:

§195.452 Pipeline integrity management in high consequence areas.

(g) What is an information analysis? In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:

(2) Data gathered through the integrity assessment required under this section;

EP Crude did not to include the threat of SCC on Line S1 into the Information Analysis performed on February 28, 2011. Thus, EP Crude failed to analyze all available information about the integrity of Line S1 and the consequences of a failure prior to the ILI run completed on September 19, 2014.

The EP Crude Procedure IMP-SEC6-01 Information Analysis - Line Pipe, section 2.1.10.8 states,

> *"Indicate if tests for the presence of SCC have been performed on the segment. If tested, identify the number of SCC indications that were found."*

On March 15, 2009, an MFL inline inspection (ILI) tool was run on the Line S1 pipeline segment - 30" Jones Creek to Cedar. Following the ILI run, Integrity Dig #5 was performed on April 13, 2010 for 15 corrosion anomalies. SCC was discovered during the integrity dig and investigation. The SCC was not one of the 15 anomalies called by the ILI run. The investigation determined the SCC was not 'Signification SCC' as defined in NACE SP 0204-2008 Stress Corrosion Cracking (SCC) Direct Assessment Methodology. Significant SCC is defined as,

> *"An SCC cluster was defined to be "significant" by the Canadian Energy Pipeline Association (CEPA) in 1997 provided that the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. CEPA also defines the interaction criteria. The presence of extensive and "significant" SCC typically triggers an SCC mitigation program (see discussion under Post-Assessment Step), but a crack that is labeled "significant" is not necessarily an immediate threat to the integrity of the pipeline."*

The EP Crude Pipeline Integrity Program Std. 9009 Stress Corrosion Cracking Definition, section 2.0 Definitions, states,

> *"(3) **Insignificant SCC** - SCC which is neither Significant SCC nor is associated with dents, gouges, etc.*
> *(9) **Significant SCC** - axially or circumferentially oriented SCC (which is not associated with dents, gouges, or other geometrical pipeline features) where the SCC depth is greater than 50% WT, or the SCC depth is greater than 10% WT and has an interacting length greater than or equal to 75% of the critical length of a 50% through wall flaw that would fail at a stress level of 110% SMYS."*

In February 2014 during the PHMSA inspection, it was discovered that the Information Analysis performed on the pipeline segment on February 8, 2011 omitted the presence of the SCC on Line S1. EP Crude informed PHMSA, the SCC had been left out of the Information Analysis and Risk Algorithm by mistake. EP Crude planned to perform a new Information Analysis prior to the scheduled 2014 ILI run. The ILI was scheduled for March 15, 2014, but due to construction activities associated with the Seaway Loop Project in close proximity to Line S1, a deviation was filed and the ILI run was rescheduled for July 25, 2014. EP Crude completed the Information Analysis on June 27, 2014 prior to the rescheduled ILI run. The presence of SCC was included in the Information Analysis and Risk Algorithm. Due to several more issues with the *rescheduled ILI run, two additional deviations were taken prior to completing the run. EP Crude stated that due to a time constraint resulting from the 3 deviations, the ILI run was performed using an MFL tool and a Deformation tool as originally scheduled. The tool selection was not changed to include a crack detection tool due to no availability of said tool.*

The Information Analysis recommended that additional data gathering and analysis activities be performed as defined in the SCC process for line pipe which contains non-FBE coating and where NACE insignificant SCC has been identified. Crack detection tool assessments are being performed on AID's 849 and 850 of the Seaway Pipeline to identify long seam cracks due to railroad fatigue. EP Crude will evaluate the results of the upcoming Crack Detection Tool assessments for SCC. EP Crude will re-inspect the SCC if the evaluation supports SCC re-inspection.

Although three deviations were taken prior to the ILI run, the assessment was completed on September 19, 2014 which was before the 68 month deadline of November 15, 2014.

The failure of EP Crude to include the presence of SCC in the Information Analysis in a timely manner prior to the 2014 ILI run, resulted in the SCC threat exclusion during the tool selection process. Therefore, EP Crude failed to analyze all available information about the integrity of Line S1 and the consequences of a failure prior to the ILI run completed on September 19, 2014.

<u>Enterprise Response to Item 5:</u>

Enterprise instituted a number of improvements to integrity engineering processes in order to better identify and track occurrences of Stress Corrosion Cracking. Namely, our Correlation Report, NDE Report, Pipeline Integrity Engineer Review Tracker, and our Information Analysis documents were updated.

Should you have any questions, require additional information or wish to discuss this matter in greater detail, please do not hesitate to contact our office. Enterprise welcomes the opportunity to work with PHMSA regarding the safe operation of our pipelines.

Sincerely,

Graham Bacon
Executive Vice President, Operations & Engineering