DOT U.S. Department of Transportation
PHMSA Pipelines and Hazardous Materials Safety Administration
OPS Office of Pipeline Safety
Southwest Region

Principal Investigator	Molly Atkins
Region Director	R.M. Seeley
Date of Report	2/24/2014
Subject	Failure Investigation Report – Enbridge Pipelines, LLC, Tank 3013 24-inch Fill Line failure in Cushing, OK

Operator, Location, & Consequences

Date of Failure	5/17/2013[1]
Commodity Released	West Texas Intermediate Crude Oil
City/County & State	Cushing, Lincoln County, OK
OpID & Operator Name	31947, Enbridge Pipelines, LLC
Unit # & Unit Name	22464, Cushing Tank Farm
SMART Activity #	143591
Milepost/Location	Cushing, OK, Tank Farm
Type of Failure	Internal Corrosion, Microbiologically Influenced (MIC)
Fatalities	0
Injuries	0
Description of area impacted	No off-site impacts; however, there were on-site impacts to vegetation, containment ponds, and small animals/reptiles
Property Damage	$13,844,274 (Final Report)[2]

[1] Event occurred on May 17, 2013, but was not discovered or reported until May 18, 2013.
[2] Enbridge Pipelines, LLC. (Revision: 12/18/2013). *7000.1 Report 20130208*.

Executive Summary

On the afternoon of May 18, 2013, Enbridge Pipelines, LLC (Enbridge), reported a release of approximately 2,500 barrels of crude oil from its Tank 3013 fill line into on-site containment ponds. The leak originated on the Tank 3013 fill line located outside of tank containment dike areas in a drainage swale on the morning of Friday, May 17, 2013. The leak—which was not visible at the surface due to vegetation in the drainage swale—was not identified until an odor was detected by operations personnel, prompting further investigation into line balance calculations and site conditions. The leak was observed and confirmed at 1:00 p.m. CT on Saturday, May 18, 2013.

Tank 3013 and its fill line were deinventoried and isolated, a unified command response center was set up, and clean-up began. The Tank 3013 fill line was excavated to investigate the source of the leak, which was found on the bottom of the pipe at the low point of the fill line. The failed pipe section was removed and transported to a metallurgical laboratory for examination and testing. The Tank 3013 fill line was replaced in its entirety. In December 2013, after the new line was tested, Tank 3013 and the fill line were returned to service.

There were no injuries, fatalities, fires, explosions, or off-site impacts as a result of this leak. On-site impacts were limited to vegetation, soil, and retainment pond areas. Approximately 2,246 barrels of crude oil were released and 2,071 barrels were recovered. Forensic metallurgical analysis determined that the immediate cause of failure was internal corrosion.

System Details

The Cushing Tank Farm is operated by Enbridge, which has a terminal located in Cushing, Oklahoma. The Enbridge terminal is 2 miles long and comprised of three operating areas: the North, Central, and South Terminals. The South Terminal is located in Lincoln County, Oklahoma, while the Central and North Terminals are in Payne County, Oklahoma. The Enbridge terminal currently has 89 breakout tanks, as well as several tanks in various stages of inspection or demolition and additional tanks currently under construction. The tally of 89 tanks was taken at the time of the most recent inspection and included 28 breakout tanks in the South Terminal, 34 breakout tanks in the Central Terminal, and 27 breakout tanks in the North Terminal. The terminal is operated by a local control room that is manned 24 hours, seven days per week.

Events Leading up to the Failure

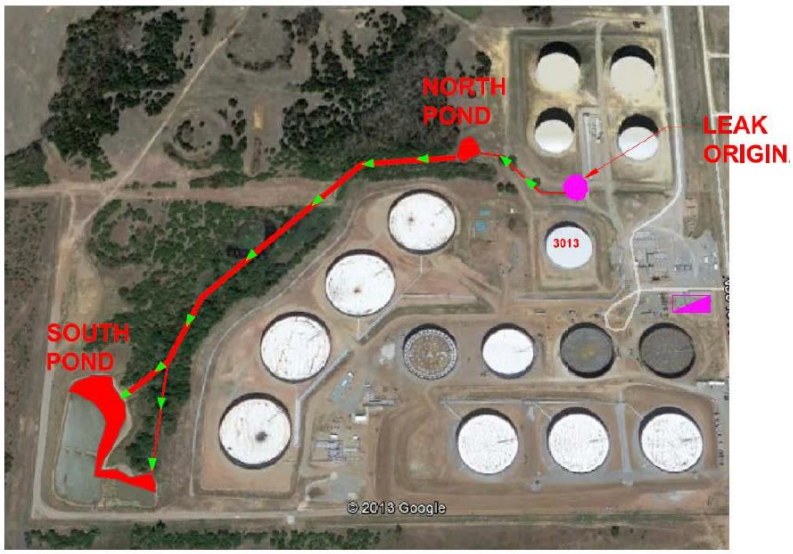
Tank 3013 and the connecting tank fill lines were purchased by Enbridge from Skelly Oil Company in 1980. The tank has operated in crude oil service from the time of purchase to the present. Tank 3013 was out of service for an American Petroleum Institute (API) 653 internal inspection from May 2011 through May 8, 2013, when the tank roof was floated by injection of 50,000 barrels of oil. On May 10, 2013, the tank level radar gage was recalibrated, causing the calculated tank volume to increase by 1,879 barrels although no additional oil was added to the tank. Tank 3013 was refilled on May 14, 2013, after which point no additional withdrawals or injections were made and the tank valves remained in their normal open position for “ready for service” mode until the time of the release.

On Friday, May 17, 2013, maintenance pigging was performed on a line that is part of the Basin Pipeline System, owned by Plains All American Pipeline, L.P. Coordination of activities related to the interface of that pipeline within the Enbridge Cushing Terminal was monitored by the controller on duty during the day shift. Enbridge outside technicians worked with the Plains All American Pipeline personnel who were performing the pigging and line-fill activities in the North Terminal area.

On Friday, May 17, 2013, a product movement alarm was acknowledged for Tank 3013 at 14:39:09 supervisory control and data acquisition (SCADA) time. The alarm noted a volume of (b) (7)(F) [redacted]. Despite the controller's acknowledgment of the alarm, it was not cleared at that time. No further product movement alarms were received for Tank 3013. Because there was not a second alarm during that shift, and because the controller thought the first movement alarm was related to weather and had cleared itself, the alarm remained in the stack and was not discussed in the shift hand-off (SHO).

The SHO from night shift to day shift on Saturday, May 18, 2013, did not mention anything about Tank 3013. The daily balance performed at about 7:30 a.m. Central Time (CT) noted an imbalance of approximately the same value as the tank bottom adjustment for Tank 3013; the coincidental similarity was attributed to the accounting entry rather than a possible leak because the controller did not have any indication of abnormal conditions in Tank 3013. The subsequent balance check performed Saturday morning caused the controller to make a mental note of the imbalance, which he decided to investigate further if it did not return to normal after lunch.

Around 1:00 p.m. CT on Saturday, May 18, 2013, an outside technician was returning to the control room with lunch when he detected an odor. The outside technician communicated this information to the controller, who instructed the outside technician to investigate the Tank 3013 area while he began further review of the balance information and trending data. The outside technician reported to the controller that there were no visible signs of a leak in the vicinity of Tank 3013. However, the controller asked the outside technician to continue looking and indicated that the issue might be related to Tank 3013. By this time the product was just becoming visible on the surface of the dirt bank and the containment pond, into which it was flowing. The following aerial view depicts the site layout:



Tank 3013 Site Layout

Shortly after 1:00 p.m. CT, operations personnel confirmed that oil was leaking from the 24-inch-diameter line connected to Tank 3013 at a low point in the line where it crossed below a drainage ditch. Oil was found to have migrated from the drainage ditch into a nearby containment pond and then into a second, larger containment pond via a connecting drainage creek. Upon confirmation of the leak, all connecting tank and manifold valves were closed to stop the outflow of oil. The outside technician closed the Tank 3013 isolation valve and provided the controller with leak confirmation on the Tank 3013 fill line. The controller initiated spill response notifications and set up the incident command at the Cushing Terminal office location.

Emergency Response

Operator Response

The operator identified the release shortly after 1:00 p.m. CT on May 18, 2013, after which the operator initiated its spill response plan and recovered approximately 2,071 barrels of the 2,246 barrels released. All product was contained onsite and within planned containment areas. The clean-up operations were carried out in extremely severe weather, yet did not result in injury or further release of product.

The operator reported the release to the National Response Center (NRC) Office 1047579 at 2:33 p.m. CT on May 18, 2013. The original release volume was estimated at 1,500 barrels (Appendix B).

PHMSA Response

PHMSA dispatched an accident investigator to the site. The accident investigator arrived on Sunday, May 19, 2013, and remained onsite until Wednesday, May 22, 2013.

Investigation Details

PHMSA's investigation included a detailed review of the events and associated procedures related to internal corrosion prevention, alarm response, and terminal balancing activities, as well as the numerous control room processes related to leak detection and suspected leak investigation.

Terminal piping leak detection is managed by monitoring flow rates, pressures, and tank volumes, as supplemented by the SCADA alarm system. In addition, a tank volume balance procedure is used to identify imbalances in tank levels that could indicate product loss either directly from a tank or from the associated piping.

The SCADA system was designed and is managed by the Enbridge Pipeline Control Systems and Leak Detection group in Edmonton, Canada; however, various inputs to the system are set by operations technicians in Cushing, Oklahoma. (b) (7)(F) —which is set when no tank movement is anticipated and will trigger an alarm if the calculated tank movement exceeds the set value. (b) (7)(F) (b) (7)(F). This volume was chosen due to the size of the tank (capacity greater than 100,000 barrels) and to avoid nuisance alarms during weather events due to shifting of floating roofs and product movement inside the tank, which can generate barrel movement volume ranging from 200 to 300 barrels. Fluctuation of the floating roof during weather events can be an inch or more. If the volume is not set high enough to account for such movements the tank movement alarms would not be meaningful during adverse weather events. In addition to tank balancing, other leak detection methods include visual checks and surveillance by camera. These methods are intended to work in concert with the tank alarms as a comprehensive set of actions designed to detect leaks as early as possible.

Terminal monitoring by outside technician personnel includes a drive-through of the facility on a two-hour cycle, use of the Commodity Movement Tracking System for volumetric measurements on both a two-hour and a daily basis, and surveillance cameras installed inside the tank areas.

Metallurgical Examination

Following initial clean-up, an 8.5-foot section of the failed pipe was sent to Det Norske Veritas Germanischer Lloyd (DNVGL) in Columbus, Ohio, for metallurgical analysis. A summary of DNVGL's findings may be found later in this section, and the complete metallurgical report is provided in Appendix D.

DNVGL's report indicated that the leak in the 24-inch pipe originated from a hole 1.4 inches long and 0.8 inches wide (circumference) that was located beneath black deposits in an area of discrete internal corrosion on the bottom of the pipe. In total, there were four corrosion pits found in the pipe. The leak hole was 100 percent through the pipe wall, while the remaining three pits were between 35 percent and 53 percent through the pipe wall. There was no evidence of general

corrosion or pitting on the external surface of the pipe, and the pipe coating was well adhered in areas away from the leak site.

The pipeline steel's tensile properties, Charpy properties, and chemical composition were shown to meet the API 5LX Grade X70 line pipe steel requirements in place at the time of manufacture. The average wall thickness measured was 0.284 inches, slightly greater than the specified value of 0.281 inches shown on the construction drawings.

High to very high concentrations of aerobic, anaerobic, acid-producing, sulfate-reducing, and iron-related bacteria were detected on the inside surface of the pipe at the leak site. Additionally, low to moderate concentrations of all five bacteria types were detected in deposits removed from the leak location in an area with no significant corrosion. The presence of microorganisms on the pipe surfaces, combined with higher levels of bacteria present at the leak site, indicates that microbiologically induced corrosion (MIC) is likely the primary corrosion mechanism.

DNVGL's analysis determined that the leak occurred as a result of internal corrosion that propagated through the pipe wall at the 6:17 o'clock position. The internal corrosion was likely exacerbated due to the accumulation of deposits/sediments caused by non-flowing conditions. There was no indication that the failure involved a mechanical (i.e. strength-related) component.

Figure 1 provides a field photograph of the failure location and a close-up view of the pipe leak location:

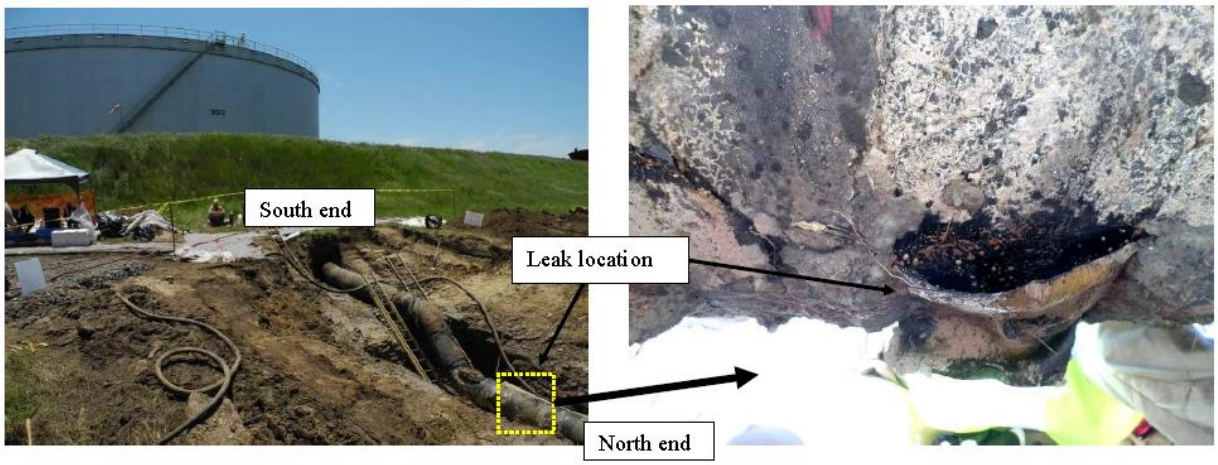


Figure 1. Field photographs showing the pipe section that leaked, prior to removal: overall site view (Left) and close-up (Right).

Findings & Contributing Factors

Enbridge completed a detailed incident investigation and shared their findings with PHMSA, including the following analysis of the events that delayed the detection of the release (Appendix E). These events corroborated the findings of on-site interviews of operations personnel conducted by PHMSA immediately after the release. The following is a summary of findings from the operator's analysis of the delayed detection:

A tank movement alarm was received approximately 2.5 hours after the leak began when a tank movement limit of 310 barrels was exceeded. This was mistakenly believed to be a false alarm due to normal variations in calculated volume caused by weather effects.

Tank balancing calculations conducted every 2 hours on May 17-18 also revealed unexplained losses in tank volume. These were not acted upon, however, because the utilized volume limit was not exceeded in any of the 2-hour time periods.

Finally, a 1,573-barrel-loss in tank volume was recorded by the 24-hour tank balance procedure conducted the morning of May 18. This also was not acted upon, as it was mistakenly believed to be related to a previous instrumentation calibration correction.

These issues allowed a significantly larger volume of crude oil to be released than otherwise would if the SCADA information had been correctly interpreted and acted upon.

In their investigation findings, Enbridge also provided a summary of the events that took place on the day of the intial leak and the actions undertaken following the discovery of the leak. Their findings detailed actions Enbridge personnel should have taken in reponse to the original leak on May 17, 2013, and identified potential shortcomings in their procedures. These findings included a detailed investigation regarding why the leak went undetected for nearly 24 hours, resulting in a significantly increased volume release.

Conclusions

PHMSA concurs with the Enbridge investigation team determination that:

1. The primary cause of the leak was the presence of an undetected internal corrosion defect that extended through the pipe wall and produced a substantial crude oil release that went undetected for almost 24 hours; and

2. The consequences increased in severity due to misinterpretation of SCADA alarm and tank balance information, thereby delaying the discovery of the real reason for loss of product from the tank.

The Enbridge investigation team identified the following items that may also have contributed to this incident:

1. Existing procedures to assess alarm conditions provide Cushing CC operations technicians with little guidance regarding how such assessments should be conducted;

2. A large number of nuisance alarms went off in the control center at the same time that the tank movement alarm was received, which may have partially obscured the importance of that alarm;

3. (b) (7)(F) [redacted]

4. Cushing CC operations technicians do not have dedicated, 24-hour support staff available to help evaluate and manage alarms;

5. No documented guidance was provided to operations regarding when inhibition and/or flushing should be used as mitigation strategies;

6. Heavy vegetation in site drainage ditches and around ponds may have prevented early detection during routine drive-around site inspections; and

7. An undetected maintenance issue with an underflow pipe flume (a large corrosion hole in the pipe) allowed oil to migrate out of the upper pond, through a second drainage ditch, and into a lower pond, resulting in increased contamination and clean-up costs.

As a result of the Enbridge investigation team's key findings, the following areas received recommendations and procedural improvements aimed at the prevention of similar incidents in the future:

- Procedures for locating, inspecting, and mitigating corrosion-prone facilities' piping segments;
- Terminal operating practices related to infrequently used piping;
- Tank movement tracking and terminal alarm systems related to leak detection; and
- Control center procedures regarding recognizing and assessing leak-related alarms.

The procedures related to the prevention of internal corrosion within terminal piping were expanded to incorporate the lessons learned from this accident. Additionally, the replacement tank fill line piping was installed with an internal coating in order to minimize the likelihood of interior corrosion.

Appendices

A Enbridge Cushing Terminal Map

B NRC Report

C Operator Accident/Incident Report to PHMSA

D Laboratory Analysis PP07 8181

E Operator Incident Investigation Report and Findings

Appendix A

Enbridge Cushing Terminal Map

This document is on file at PHMSA

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1047579

INCIDENT DESCRIPTION

*Report taken at 15:33 on 18-MAY-13
Incident Type: FIXED
Incident Cause: EQUIPMENT FAILURE
Affected Area:
The incident occurred on 18-MAY-13 at 14:00 local time.
Affected Medium: OTHER CONTAINMENT ON-SITE

SUSPECTED RESPONSIBLE PARTY

Organization: ENBRIDGE
CUSHING, OK 74023

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

2101 S. LINWOOD AVE. County: LINCOLN
City: CUSHING State: OK Zip: 74023

WITHIN CUSHING TERMINAL SOUTH TANK FARM

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 1500 BARREL(S)

DESCRIPTION OF INCIDENT

A TRUNK LINE GOING TO A TANK ON THE PROPERTY IS LEAKING, THE LEAK HAS MIGRATED OUTSIDE OF A BERM AND IS SETTLING INTO A CONTAINMENT POND. CAUSE IS UNKNOWN. LINE WILL BE SEALED, DUG UP AND REPLACED.

INCIDENT DETAILS

Package: N/A
Building ID:
Type of Fixed Object: TANK FARM
Power Generating Facility: UNKNOWN
Generating Capacity:
Type of Fuel:
NPDES:
NPDES Compliance: UNKNOWN

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES:	NO	Hospitalized:	Empl/Crew:	Passenger:
FATALITIES:	NO	Empl/Crew:	Passenger:	Occupant:
EVACUATIONS:	NO	Who Evacuated:	Radius/Area:	

Damages: NO

Closure Type		Description of Closure	Length of Closure	Direction of Closure
Air:	N			
Road:	N			
Waterway:	N			

Major Artery: N

Track: N

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

EVACUATING LINE, DIGGING UP LINE, CLEANUP UNDERWAY, ALL MATERIAL CONTAINED ON-SITE
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local: OK CC
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

COLORADO INFO ANALYSIS CENTER (FUSION CENTER)
18-MAY-13 15:39
DHS PROTECTIVE SECURITY ADVISOR (PSA DESK)
18-MAY-13 15:39
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
18-MAY-13 15:39
U.S. EPA VI (MAIN OFFICE)
18-MAY-13 15:45
GULF STRIKE TEAM (MAIN OFFICE)
18-MAY-13 15:39
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
18-MAY-13 15:39
NOAA RPTS FOR OK (MAIN OFFICE)
18-MAY-13 15:39
NATIONAL RESPONSE CENTER HQ (AUTOMATIC REPORTS)
18-MAY-13 15:39
NRC SENIOR WATCH OFFICER (MAIN OFFICE)
18-MAY-13 15:45
OFC OF ENV SVC CHEROKEE NATIONS OK (MAIN OFFICE)
18-MAY-13 15:39
SAC AND FOX NATION (EMERGENCY MANAGEMENT)
18-MAY-13 15:39
DEQ OKLAHOMA (MAIN OFFICE)
18-MAY-13 15:39

ADDITIONAL INFORMATION

ALL MATERIAL EXPECTED TO STAY ON PROPERTY, WILL NOTIFY LOCAL AUTHORITIES

*** END INCIDENT REPORT # 1047579 ***

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	06/14/2013
	No.	20130208 - 18846 --- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**

Last Revision Date:	12/18/2013
1. Operator's OPS-issued Operator Identification Number (OPID):	31947
2. Name of Operator	ENBRIDGE PIPELINES (OZARK) L.L.C.
3. Address of Operator:	
3a. Street Address	1100 LOUISIANA , SUITE 3300
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77002
4. Local time *(24-hr clock)* and date of the Accident:	05/18/2013 14:00
5. Location of Accident:	
Latitude:	35.95885
Longitude:	-96.75655
6. National Response Center Report Number (if applicable):	1047579
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	05/18/2013 14:25
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	2,246.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	2,071.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	

13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	No
- If No, Explain:	The tank line was idle at the time of the leak
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	
14b. Local time pipeline/facility restarted:	
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	05/18/2013 14:00
18b. Local time Operator resources arrived on site:	05/18/2013 14:30
PART B - ADDITIONAL LOCATION INFORMATION	
1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Oklahoma
3. Zip Code:	74023
4. City	Cushing
5. County or Parish	Lincoln
6. Operator-designated location:	
Specify:	
7. Pipeline/Facility name:	Cushing Terminal
8. Segment name/ID:	Tank 3013 Line Fill
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Totally contained on Operator-controlled property
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	18
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	
PART C - ADDITIONAL FACILITY INFORMATION	
1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Terminal/Tank Farm Equipment and Piping
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe

- If Pipe, specify:	Pipe Body
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.281
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	24,000
3d. Pipe specification:	Unknown
3e. Pipe Seam , specify:	Other
- If Other, Describe:	Unknown
3f. Pipe manufacturer:	Unknown
3g. Year of manufacture:	1978
3h. Pipeline coating type at point of Accident, specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1979
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	Other
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	Yes
1a. If Yes, specify all that apply:	
- Fish/aquatic	Yes
- Birds	Yes
- Terrestrial	Yes
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	Yes
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	Yes
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	Yes
5. Water contamination:	Yes
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	Yes
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	2,246.00
5c. Name of body of water, if commonly known:	Unnamed tributary to Wildhorse Creek
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	No
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	No
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect"	

determination for this Accident site in the Operator's Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated Property Damage:	
8a. Estimated cost of public and non-Operator private property damage	$ 0
8b. Estimated cost of commodity lost	$ 30,000
8c. Estimated cost of Operator's property damage & repairs	$ 754,000
8d. Estimated cost of Operator's emergency response	$ 5,600,000
8e. Estimated cost of Operator's environmental remediation	$ 7,460,274
8f. Estimated other costs	$ 0
Describe:	
8g. Total estimated property damage (sum of above)	$ 13,844,274

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	15.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	250.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	No
- If Yes - (*Complete 5a. – 5e. below)*	
5a. Type of upstream valve used to initially isolate release source:	
5b. Type of downstream valve used to initially isolate release source:	
5c. Length of segment isolated between valves (ft):	
5d. Is the pipeline configured to accommodate internal inspection tools?	
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	
- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	

- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	=< 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Guard Patrol by Operator or its contractor" is selected in Question 8, specify the following:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	Yes
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	Yes
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	Yes
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	Yes
- If Yes:	
1a. Specify how many were tested:	3
1b. Specify how many failed:	0
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G1 - Corrosion Failure
G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column	
External Corrosion:	
Internal Corrosion:	Yes
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	Localized Pitting
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	Yes
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	Yes

- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	Yes
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	No
11. Was the interior coated or lined with protective coating?	No
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	Not applicable - Not mainline pipe
13. Were corrosion coupons routinely utilized?	Not applicable - Not mainline pipe
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	No
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	No
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	No
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	

4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	

- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause selected below is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	

- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Pump), Tank Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	

Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	

G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage	No
Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	No
1. Specify:	
- If Other, Describe:	
Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure	No
Pipeline or Equipment Overpressured	No
Equipment Not Installed Properly	No
Wrong Equipment Specified or Installed	No
Other Incorrect Operation	No
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	

2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

At 2:00 PM, a tank volume change occurred and Operations personnel discovered a leak in the Cushing South Terminal on Tank 3013. The oil made its way via ditch to a small containment pond west of tank 3013. The oil overflowed from that containment into a nearby tributary to Wildhorse Creek and made its way into the large containment pond in the South Terminal. Crews constructed dams to ensure the oil remained on the South Terminal property. The suspected tank line associated with Tank 3013 was evacuated and isolated. Oil in containment ponds was recovered by vac truck and stored in Tanks 3009 & 3010.

Piping was exposed and failed pipe will be assessed based on facility integrity plan, cut out and shipped to DNV for further investigation. Approximately 5,000 cubic yards of contaminated soil has been removed from release site. The soil has been moved to on site containment for testing and remediation. The recovery of 17,000 BBLs of oil/water is currently being separated. Once complete, a supplemental report will be filed with the revised volume of commodity recovered. Remediation and cleanup is still underway and is nearing completion. Crews are currently working on seeding the creek banks and conducting daily monitoring of the South containment pond ensuring the water quality out flow meets standard.

Update 12/18/13 - Cleanup, remediation and analytical data collection are complete. The banks of the creek have been restored to pre-existing conditions. Monitoring of the remediation site and water quality are also complete. Re-vegetation inspection will continue in 2014 to ensure remediation efforts at the site.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Appendix D

Laboratory Analysis PP07 8181

This document is on file at PHMSA

Appendix E

Operator Incident Investigation Report and Findings

This document is on file at PHMSA