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

Investigator	David York
Region Director	R.M. Seeley
Date of Report	10/5/2016
Subject	Failure Investigation Report—Tennessee Gas Pipeline Company, LLC, in-service stress corrosion cracking (SCC) failure

Operator, Location, & Consequences

Date of Failure	8/3/2015
Commodity Released	Natural Gas
City/County & State	Falfurrias/Brooks County, TX
OpID & Operator Name	19160 Tennessee Gas Pipeline Company
Unit # & Unit Name	4024 Edinburg District 409
SMART Activity #	151027
Milepost/Location	Section 403; MP 9.69
Type of Failure	Stress Corrosion Cracking (high-pH)
Fatalities	0
Injuries	0
Description of area impacted	Open field /Non-HCA
Total Costs	$191,498[1]

[1] 20150110-16929

Executive Summary

On August 3, 2015, the Tennessee Gas Pipeline Company, L.L.C. (TGP), experienced an in-service failure on their San Salvador Line 400-1 natural gas pipeline. The line ruptured at approximately 8:30 p.m. Central Standard Time (CST), 1.5 miles southeast of Falfurrias, TX. The operator in the TGP control room recognized the failure and initiated emergency response procedures, notifying company operations personnel and shutting down the system. The TGP reported the release to the National Response Center at 9:49 p.m. local time.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order (CAO) on August 6, 2015, requiring the TGP to take certain corrective actions following the release. The TGP sent samples of the failed pipe to Antech Labs in Houston, TX, for metallurgical and mechanical analysis, which was performed by EN Engineering (ENE). The final report, dated September 18, 2015, concluded the failure was due to environmentally influenced cracking within the pipe material. The failure originated in the pipe body and spread along the long weld seam of the pipe.

The estimated 50 million cubic feet of escaped gas did not ignite; several residences were temporarily evacuated, however, and roadways were closed by County emergency responders in the hours following the rupture. No fatalities or injuries were reported as a result of this incident.

System Details

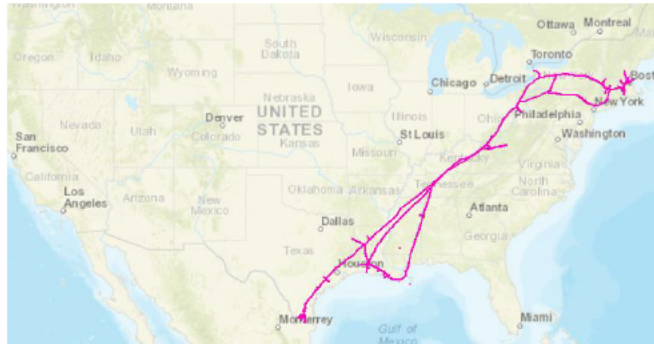


Figure 1: Tennessee Gas Pipeline

The TGP is a subsidiary of Kinder Morgan Energy Partners, L.P. Their 11,900-mile natural gas pipeline originates in Texas, travelling eastward through Louisiana before terminating in the northeastern United States.

The 98.79-mile segment designated Line 400-1 was initially constructed by the TGP in 1947 and has always transported natural gas. The TGP operates a parallel mainline designated Line 400-2 that transports gas south through five counties in Texas, from Agua Dulce Compressor Station to Edinburgh Compressor Station.

Pipe Specifications

The specified outside diameter of Line 400-1 is 16 inches, and the wall thickness is 0.25 inches. The API 5L X42-specified pipe, originally manufactured in 1947, was crafted with a direct current electric resistance seam weld (DC-ERW) by Youngstown Sheet & Tube. The pipe did not have an internal coating, and the external coating consisted of coal tar enamel.

The pipeline operates with a design-limited 903 psig maximum allowable operating pressure, which corresponds to a stress level of 68% of the material's specified minimum yield strength (SMYS).

Events Leading up to the Failure

From May 1 through August 2, 2015, the average operating pressure of Line 400-1 ranged from 781 to 853 psig. Just prior to the failure Line 400-1 was operating normally at approximately 827 psig, transporting gas south in both Line 400-1 and parallel Line 400-2. Both the upstream and downstream compressor stations were online.

The rupture occurred at approximately 8:30 p.m. local time on August 3, 2015. Controllers for the TGP received a critical alarm for a pressure rate change at 8:36 p.m., and by 8:37 p.m. a call was received by a TGP employee describing a possible leak near Highway 285 outside of the city of Falfurrias, TX.

Emergency Response

The TGP dispatched personnel to the failure site and to mainline valves located upstream and downstream of the incident location. Responding TGP personnel arrived at the failure site around 8:45 p.m., and took the upstream Agua Dulce Compressor Station offline at approximately 8:46 p.m. The TGP depressurized and isolated an 11.16-mile section of pipe containing the failure segment and mainline valves. The Falfurrias Fire Department temporarily closed a five-mile section of Highway 285 and evacuated homes in a half-mile radius (shown in Figure 2), allowing residents to return just after midnight.

PHMSA's Office of Pipeline Safety (OPS) Southwest Region received notification of the incident from the TGP on August 3, 2015, at 9:49 p.m. local time, prior to the filing of the telephonic report to the National Response Center. Responding to the telephonic notification, representatives from the Pipeline Safety department of the Railroad Commission of Texas reported to the incident site. Following determination of jurisdictional classification, these representatives departed.

Figure 2: Map of Incident Location

OPS conducted a site evaluation on August 4, 2015; however, due to safety concerns immediately following the incident, initial observation was conducted at a distance from the pipe. The rupture appeared to have stemmed from the long seam and travelled along approximately 55 feet of pipe, with the crack stopping at the adjacent pipe sections. The rupture did not eject the pipe from the ditch, but expelled the ground cover a distance from the crater, which measured roughly 70 feet long by 30 feet wide. The external coating was found to be damaged during the incident, with large sections no longer bonded to the pipe surface. There were no visible signs of mechanical damage to the pipe or evidence of external/internal corrosion.

Summary of Initial Start-Up and Return-to-Service

Following this visit by OPS to the failure site, PHMSA issued a CAO to the TGP on August 6, 2015. The CAO covered almost 100 miles of Line 400-1 and defined two sections: a contiguous 98.79-mile "Affected Segment" between Edinburgh Compressor Station and Agua Dulce Compressor Station, and an 11.16-mile "Isolated Segment" (including the incident location) bounded by mainline block valves.

[redacted]

The CAO limited the operations of the two defined segments, and required the following elements be adhered to:

- 20% operating pressure restriction
- Complete mechanical & metallurgical testing
- Complete a root cause failure analysis (RCFA)
- Complete & follow a remedial work plan (RWP)
- Development of a restart plan

The damaged portion of pipe was replaced with 16-inch outer diameter, 0.312-inch wall, grade API-5L X65 pipe with fusion-bonded epoxy external coating which was manufactured by the Stupp Corporation. Approximately 97 feet of this pipe was hydrostatically tested to 2,368 psig on August 6, 2015. The TGP installed 62.8 feet August 7, 2015, completing the repair of the pipeline damaged during the incident.

The TGP completed the testing, RCFA, restart plan, and elements of the RWP. With the approval of the director of OPS Southwest Region, the TGP restarted Line 400-1 on January 17, 2016, initially limiting the restart pressure to 80% of the actual operating pressure immediately prior to the failure. Following an instrumented leak survey on the Affected Segment OPS removed the pressure restriction, returning the line to normal operation on February 4, 2016, without incident.

Investigation Details

The failure occurred within the TGP's right-of-way, which is shared with the 400-2 Line, a 26-inch outer diameter natural gas pipeline also operated by the TGP and unaffected by the incident. The pipeline route was slightly uphill to the south, and there was no measureable bend in the joint where the failure occurred. The site is outside the city limits of Falfurrias, TX, and the closest residence was more than 500 feet to the north. There was a total of 1.01 miles of Line 400-1 in a high consequence area (HCA); however, the incident did not occur within an HCA. Reports show that local officials initially established a 5-mile evacuation radius, eventually reducing it to a half-mile radius. The incident did not result in a fire or fatalities.

Four years of cathodic protection potentials prior to the failure at test locations nearest to the incident location show the level exceeded the applied minimum criteria of -0.85 millivolts. Even though this section of the pipeline appeared to be adequately protected, however, partial shielding by dis-bonded coatings could have caused the pipeline to lie in the potential range for cracking.[2] The original coal tar enamel external coating was absent from the ruptured section of pipe; however, this type of coating is known to promote the environment needed for stress corrosion cracking (SCC) when dis-bonded from the pipe surface.

Figure 1 : Photo looking North at failure site

Prior to the incident on August 15, 2015, there were no documented in-service SCC failures on Line 400-1. The TGP has experienced previous hydrostatic test failures due to SCC, however, all of which occurred in the valve section just upstream of Edinburgh Compressor Station. The segment where the failure occurred was successfully hydrostatically tested to 1,225 psi (or 93.33% SMYS) in 1997.

In the section where the incident occurred, [redacted], the TGP had not experienced a leak or test failure due to SCC. The TGP's pipeline examination process includes investigating for signs of SCC under circumstances where coating is dis-bonded or bare pipe exists. The TGP utilizes a written procedure to mitigate SCC, referencing Appendix A-3 of ASME B31.8S, which contains criteria for considering the susceptibility of a pipeline system to the threat of SCC. The TGP considered the August incident an exception, as all company criteria for the identification of SCC were not met at the time of the failure. It would appear that the lack of a comparable historical failure, coupled with the metallurgical report's findings that existing manufacturing defects influenced the colonies of SCC,

[2] OPS TTO#8 Stress Corrosion Cracking Study, Baker (2005).

allowed [redacted] to bypass SCC detection. This prevented it from being included in the operator's SCC Integrity Management Program (which applies to both covered and non-covered segments).

The review of the TGP's records show that the 98.79-mile segment of Line 400-1 between Edinburgh Compressor Station and Agua Dulce Compressor Station contained pipe that was susceptible to the threat later determined to be the cause of the rupture.

Hydrostatic Spike Testing
The CAO required the TGP to develop and follow a remedial work plan to address any known factors and causes of the incident.

The Affected Segment was hydrostatically tested in six sections from October 28, 2015, through December 11, 2015. The TGP followed their written procedure in the remedial work plan to complete 1-hour spike tests immediately followed by a 7-hour strength test. The pressure test records provided to OPS by the TGP indicated that the entire segment, mostly comprised of 1947 X-42 16-inch outer diameter Youngstown Steel pipe, was subjected to a hydrostatic spike test above 100% SMYS and a 7-hour test corresponding to a stress level over 95% SMYS of the lowest strength pipe. The testing resulted in 15 failures through 5 test sections, including an instance where the pipe failed during the spike test at a pressure level below a previous test failure. Failures such as these were anticipated when testing this vintage of pipe to over 100% SMYS, particularly considering that the Affected Segment was not previously subjected to a Subpart J pressure test.

The failed pipe was removed and sent to An-Tech Laboratories in Houston, TX, for failure analysis, which revealed nine of the testing failures were due to manufacturing defects related to the pipe's long seam fusion and heat-affected zone. The remaining failures were due to axially oriented high-pH SCC. All SCC testing failures occurred in pipe similar to that impacted by the incident on August 3, 2015: 16-inch outer diameter, 0.25in wall thickness, APL 5L Grade X42, ERW, with coal tar enamel external coating manufactured in 1947 by Youngtown Sheet & Tube. Test failure pressures ranged from approximately 85-105% SMYS.

Line 400-1 was repaired following each failed hydrostatic spike test by replacing the damaged pipe segments, and testing was completed December 12, 2015.

Metallurgical Analysis
In accordance with the CAO issued by OPS following the incident, the TGP secured ENE of Chicago, IL, to perform both mechanical and metallurgical testing of the failed pipe. Following a preliminary examination at the failure site on August 4, 2015, approximately 60 feet of pipe was removed from the site and shipped to Antech Laboratories in Houston, TX.

The ENE found the fracture initiation area, located at the 3:50 o'clock position, was "approximately 7 feet, 1.66 inches and 7 feet, 9.34 inches from the upstream weld." This places the fracture origin in the pipe base metal, within the weld heat-affected zone and adjacent to the seam fusion line. Examination found oxidation indicative of a preexisting crack, and revealed the fracture grew inward from the pipe wall's outer diameter, measuring at 0.226 inches at the deepest point. Magnetic particle inspection of the surfaces adjacent to the fracture's origin revealed several axially oriented linear indications, typical of environmentally assisted cracking.

Three samples were selected for examination with a scanning electron microscope (SEM). The SEM analysis shows the fracture surface was "heavily corroded," indicating signs of mechanical damage, preexisting intergranular cracking, and final overload shear fractures.

The ENE found that "outside of the initiation area, the fracture propagated in and along the weld line both upstream and downstream, for the entire joint, and arrested in the upstream and downstream joints of pipe."

Metallographic analysis revealed the presence of seams and oxide inclusions near the fracture surface on both the outer and inner diameter of the steel, and concluded the intergranular cracking was linked with the aforementioned inclusions.

Hardness tests performed did not indicate that the hardness of the base steel contributed to the cause of the failure, and chemical and mechanical property testing also determined the pipe met the requirements of 1947 vintage API 5L Grade X42 pipe.

The ENE concluded the rupture was caused by high-pH SCC (also known as environmentally assisted cracking), as well as the intergranular attack linking with preexisting oxide inclusions, laps, and seams in the base metal.

Findings and Contributing Factors

PHMSA's findings concur with the ENE metallurgical report that the rupture likely occurred due to a reduction in the pipe's capacity to safely operate after high-pH SCC initiated in the outer diameter and grew through the pipe wall. This is supported by ENE's metallurgical analysis that discovered:

- Preexisting crack-like features in the origin area;
- A colony of axially oriented cracks adjacent to the fracture;
- Intergranular propagation of cracks and crack tips.

Contributing to the failure was the exclusion of [redacted] from the operator's SCC Management Program. The TGP manages stress corrosion cracking through their operations and maintenance program, which applies to both HCA and non-HCA areas. Using guidance from ASME B31.8S, the TGP relied on the gathering and integration of historical data to identify the threat of SCC in [redacted] Under this process, however, SCC in [redacted] would remain undetected without hydrostatic leaks or in-service failures until the opportunity for discovery presented itself through unrelated pipeline work or failure. A root cause failure analysis was performed by Integrity Plus out of Fort Collins, CO, as required by the CAO. Using the Systematic Cause Analysis Technique developed by Det Norske Veritas Germanischer Lloyd (DNV GL), the analysis determined the incident root cause should be classified under Section 10.3, "Inadequate standards, specifications, and/or design criteria," related to the TGP's SCC management program. This report provided the TGP with corrective actions, which were later developed into the RWP required by the PHMSA-issued CAO.

Appendices

A Map of Failure Site

B NRC Report #1124690

C Form PHMSA F 7100.2 #201504110-16929

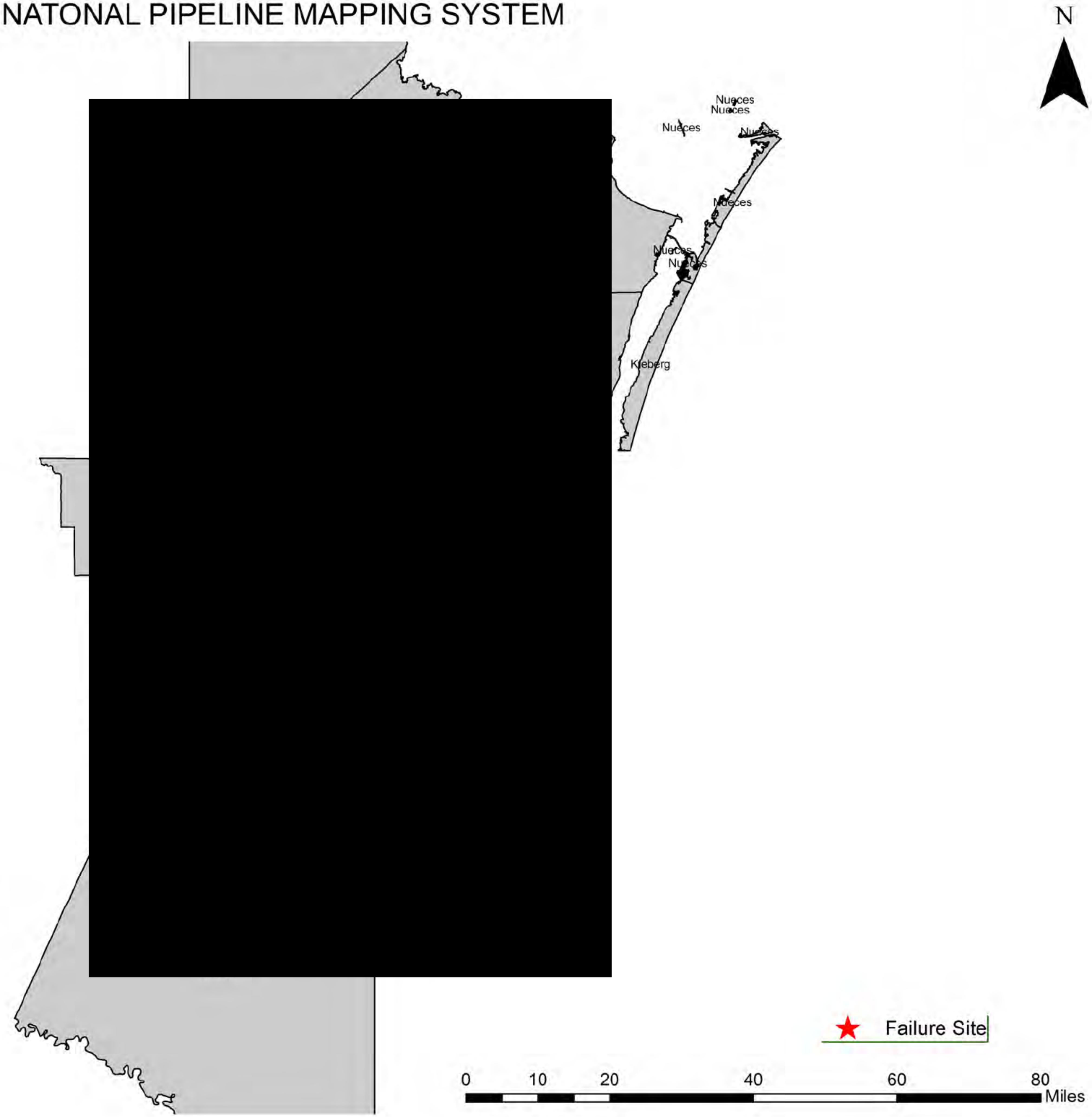
D EN Engineering—Metallurgical Analysis of 16 inch OD x 0.250 inch WT API 5L X42 ERW TGP San Salvador 400-1 Line Failure (Project # 156645.00) 9/18/2015

E Integrity Plus: San Salvador Line 400-1 Root Cause Analysis report 11/3/2015

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

NATONAL PIPELINE MAPPING SYSTEM



NRC Number: 1124690

Call Date: 08/03/2015 **Call Time:** 22:49:00

Caller Information

First Name:	KRISTIN	Last Name:	VAN DER LAAN
Company Name:	TENNESSEE GAS PIPELINE		
Address:	1001 LOUISIANA ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	77002
Phone 1:	7202368666	Phone 2:	
Organization Type:	PRIVATE	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	KRISTIN	Last Name:	VAN DER LAAN
Company Name:	TENNESSEE GAS PIPELINE		
Address:	1001 LOUISIANA ST.		
City:	HOUSTON	State:	TX
Country:	USA	Zip:	77002
Phone 1:	7202368666	Phone 2:	
Organization Type:	PRIVATE		

Spill Information

State:	TX	County:	BROOKS
Nearest City:	FALFURRIAS	Zip Code:	

Location

Spill Date:	08/03/2015 (mm/dd/yyyy)	Spill Time:	20:36:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

NATURAL GAS IS RELEASING FROM A PIPELINE (UNKNOWN SIZE) DUE TO AN UNKNOWN CAUSE AT THIS TIME AFTER THEY NOTICED A PRESSURE DROP.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
NATURAL GAS	ONG	0 UNKNOWN AMOUNT	

Medium Type: <- Select Medium Type ->

Additional Medium Information:

ATMOSPHERE

Injuries:		Fatalites:	
Evacuations:	(•) Yes ( ) No ( ) Unknown	No. of Evacuations:	
Damages:	( ) Yes ( ) No (•) Unknown	Damage Amount:	
Federal Agency Notified:	( ) Yes ( ) No (•) Unknown	State Agency Notified:	( ) Yes ( ) No (•) Unknown
Other Agency Notified:	( ) Yes ( ) No (•) Unknown		

Remedial Actions

THEY ARE IN THE PROCESS OF ISOLATING THE PIPELINE ON EITHER END.

Additional Info

PHMSA WILL BE NOTIFIED. AN UNKNOWN NUMBER OF HOMES AND PEOPLE WERE EVACUATED BY THE FIRE DEPT FOR A 5 MILE RADIUS. THE ROAD CLOSURE IS STILL ONGOING.

Latitude

Degrees: Minutes: Seconds: Quadrant:

Longitude

Degrees: Minutes: Seconds: Quadrant:

Distance from City: Direction: E

Section: Township:

Range: Milepost:

Rescinded **Comments** (max 250 characters)

<< Previous 2..2 of 2 << Save >>

NOTICE: This report is required by 49 CFR Part 191. 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: 2137-0522 EXPIRATION DATE: 10/31/2016

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	09/02/2015
	No.	20150110 - 16853 (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING 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/library/forms.*

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	09/02/2015
1. Operator's OPS-issued Operator Identification Number (OPID):	19160
2. Name of Operator	TENNESSEE GAS PIPELINE COMPANY
3. Address of Operator:	
3a. Street Address	1001 LOUISIANA ST SUITE 1000
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code:	77002
4. Local time *(24-hr clock)* and date of the Incident:	08/03/2015 20:36
5. Location of Incident:	
Latitude:	27.22217
Longitude:	-98.11031
6. National Response Center Report Number (if applicable):	1124690
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	08/03/2015 21:49
8. Incident resulted from:	Unintentional release of gas
9. Gas released: (select only one, based on predominant volume released)	Natural Gas
- Other Gas Released Name:	
10. Estimated volume of commodity released unintentionally - Thousand Cubic Feet (MCF):	50,740.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	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 fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	Yes
- If No, Explain:	

- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	08/03/2015 22:06
15b. Local time pipeline/facility restarted	
- Still shut down? (* Supplemental Report Required)	Yes
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	100
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident– effective 10-2014, changed from "Incident" to "failure"	08/03/2015 20:36
19b. Local time operator resources arrived on site	08/03/2015 21:30

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Incident onshore?	Yes
- Yes (Complete Questions 2-12)	
- No (Complete Questions 13-15)	
If Onshore:	
2. State:	Texas
3. Zip Code:	78355
4. City	Falfurrias
5. County or Parish	Brooks
6. Operator designated location	Survey Station No.
Specify:	[redacted]
7. Pipeline/Facility name:	San Salvador (400-1)
8. Segment name/ID:	Line 400-1
9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Incident :	Pipeline Right-of-way
11. Area of Incident (as found) :	Underground
Specify:	Under soil
Other – Describe:	
Depth-of-Cover (in):	33
12. Did Incident occur in a crossing?	No
- If Yes, specify type 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 Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Onshore Pipeline, Including Valve Sites
3. Item involved in Incident:	Pipe
- If Pipe – Specify:	Pipe Seam
3a. Nominal diameter of pipe (in):	16
3b. Wall thickness (in):	.250
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	42,000

3d. Pipe specification:	X42
3e. Pipe Seam – Specify:	Longitudinal ERW - Low Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Youngstown
3g. Year of manufacture:	1947
3h. Pipeline coating type at point of Incident – 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. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	1947
5. Material involved in Incident:	Carbon Steel
- If Material other than Carbon Steel or Plastic – Specify:	
6. Type of Incident involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other – Describe:	
- If Rupture - Select Orientation:	Other
- If Other – Describe:	Under investigation
Approx. size: in. (widest opening):	16
by in. (length circumferentially or axially):	144
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Class Location of Incident:	Class 2 Location
2. Did this Incident occur in a High Consequence Area (HCA)?	No
- If Yes:	
2a. Specify the Method used to identify the HCA:	
3. What is the PIR (Potential Impact Radius) for the location of this Incident? Feet:	332
4. Were any structures outside the PIR impacted or otherwise damaged due to heat/fire resulting from the Incident?	No
5. Were any structures outside the PIR impacted or otherwise damaged NOT by heat/fire resulting from the Incident?	No
6. Were any of the fatalities or injuries reported for persons located outside the PIR?	No
7. Estimated Property Damage :	
7a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 6-2011, "paid/reimbursed by the Operator" removed	$ 0
Estimated cost of gas released unintentionally – effective 6-2011, moved to item 7f	
Estimated cost of gas released during intentional and controlled blowdown – effective 6-2011, moved to item 7g	
7b. Estimated cost of Operator's property damage & repairs	$ 40,601
7c. Estimated cost of Operator's emergency response	$ 3,312
7d. Estimated other costs	$ 0
Describe:	
7e. Property damage subtotal (sum of above)	$ 43,913
<u>Cost of Gas Released</u>	
7f. Estimated cost of gas released unintentionally	$ 147,585
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 0
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 147,585
Total of all costs	$ 191,498

PART E - ADDITIONAL OPERATING INFORMATION	
1. Estimated pressure at the point and time of the Incident (psig):_	827.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	903.00
Added 10-2014 2a. MAOP established by 49 CFR section:	192.619(a)(2)
- If Other, specify:	
3. Describe the pressure on the system or facility relating to the Incident:	Pressure did not exceed MAOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP?	No
- If Yes - (*Complete 4a and 4b 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?	Yes
- If Yes - (*Complete 5a. – 5e. below):*	
5a. Type of upstream valve used to initially isolate release source:	Manual
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	58,925
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- 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?	No
- If Yes, which operational factors complicate execution? *(select all that apply)*	
- Excessive debris or scale, wax, or other wall build-up	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other	
- If Other, Describe:	
5f. Function of pipeline system:	Transmission System
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?	Yes
- If Yes:	
6a. Was it operating at the time of the Incident?	Yes
6b. Was it fully functional at the time of the Incident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
7. How was the Incident initially identified for the Operator?	SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations)
- If Other – Describe:	
7a. If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 7, specify:	
8. 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 Incident?	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 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)*	The rupture was not related to controller actions and the controller notified TGP Operations as soon as the incident was identified.
- If Yes, Descr be 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	
- 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	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above –	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

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

PART G - APPARENT CAUSE

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

Apparent Cause:	G8 - Other Incident Cause

G1 - Corrosion Failure - *only one **sub-cause** can be picked from shaded left-hand column*

Corrosion Failure – Sub-cause:	
- 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 incident?	
- If Yes, Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the incident?	
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:	
- If Other, Describe:	
7. Cause of corrosion *(select all that apply)*:	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- 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	
- Other	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*:	
- Low point in pipe	
- Elbow	
- Drop-out	
- Other	
- If Other, Describe:	
10. Was the gas/fluid treated with corrosion inh bitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. 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 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:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	

- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. 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 examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, 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, Descr be:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Descr be:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Descr be:	
- 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 Incident 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 Previous Damage Due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Incident" (From Part C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Incident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Year:	
- Ultrasonic	
Year:	
- Geometry	
Year:	

- Caliper	
Year:	
- Crack	
Year:	
- Hard Spot	
Year:	
- Combination Tool	
Year:	
- Transverse Field/Triaxial	
Year:	
- Other:	
Year:	
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 Incident?	
- 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 Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident 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 Incident 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	
Year:	
- Guided Wave Ultrasonic	
Year:	
- Handheld Ultrasonic Tool	
Year:	
- Wet Magnetic Particle Test	
Year:	
- Dry Magnetic Particle Test	
Year:	
- Other	
Year:	
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? - Yes - No	
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 vis ble 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, then one predominant second level CGA-DIRT Root Cause as well*):	
- Predominant first level CGA-DIRT 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 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, Descr be:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Incident?	
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 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:	
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 Incident?	
- 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 Incident :	
Most recent year conducted:	
- If Yes, but the point of the Incident 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 Incident 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 - Pipe, Weld, or Joint Failure	**Use this section to report material failures ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is "Pipe" or "Weld."** Only one **sub-cause** can be selected from the shaded left-hand column

Pipe, Weld or Join Failure – Sub-Cause:	
1. The sub-cause shown above 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	
2. List contr buting 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:	
- If 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 Incident?	
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 Incident?	
- 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 Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident 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 Incident 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:	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	

- Power Failure	
- Stopple/Control Fitting	
- Pressure Regulator	
- ESD System Failure	
- Other	
- If Other, Describe:	
- If Compressor or Compressor-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 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 gas/fluid	
- 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:	
- If Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure:	
1. Specify:	
- If Other, Describe:	
- If Other Incorrect Operation:	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Incident 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 Incident:	
5. Was the task(s) that led to the Incident 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 Incident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Incident Cause – Sub-Cause:	Unknown
- If Miscellaneous:	
1. Describe:	

- **If Unknown:**	
2. Specify:	Still under investigation, cause of Incident to be determined* (*Supplemental Report required)

PART - H NARRATIVE DESCRIPTION OF THE INCIDENT

On 08/03/2015 at approximately 8:36pm Tennessee Gas Pipeline (TGP) gas control received a pressure rate of change critical alarm on Line 400-1.
The gas controller contacted TGP operations to dispatch personnel to the possible leak site and take TGP Station 1 offline.
The controller also confirmed that local Emergency Responders, including the Brooks County Sheriffs department, were on-site.
Operations initiated emergency response. The 400-1 line from [redacted]1 was isolated at 10:06pm and the isolated section was blown down to a zero pressure by 10:15pm.
The fire marshal evacuated homes and TX DOT temporarily closed Hwy 285 for a 5 mile distance east and west until the isolated segment was blown down.
The incident is still under investigation.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Kristin van der Laan
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Date	09/02/2015

Appendix D

Metallurgical Analysis

This document is on file at PHMSA

Appendix E

Root Cause Analysis

This document is on file at PHMSA