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

Principal Investigator	Gene Roberson
Region Director	R.M. Seeley
Date of Report	11/3/2016
Subject	Failure Investigation Report—Gulf South Pipeline Company, LP Sub-sea Fitting Failure—Eugene Island Block 95

Operator, Location, & Consequences

Date of Failure	8/26/2015
Commodity Released	Natural Gas
City/County & State	Gulf of Mexico, Louisiana, Eugene Island Block 95
OPID & Operator Name	31728 Gulf South Pipeline Company, LP
Unit # & Unit Name	1534 Lafayette Offshore
SMART Activity #	152248
Milepost/Location	Eugene Island Block 95
Type of Failure	Sub-sea connection failed, causing a pipeline system in the Gulf to separate. Estimated natural gas release was 2,631 thousand cubic feet (MCF).
Fatalities	None.
Injuries	Three (3), none requiring hospitalization.
Description of area impacted	Offshore in approximately 25-30 feet of water in the Gulf of Mexico. There was no structure in the vicinity that could be affected by the release.
Property Damage	$843,098

Executive Summary

On Tuesday, August 25, 2015, C-Dive, a contractor for the Gulf South Pipeline Company, LP (Gulf South), began jetting procedures to facilitate a sub-sea pipeline abandonment project involving their 10-inch pipeline located on Eugene Island, Block 95, off the coast of Louisiana in the Gulf of Mexico. At approximately 8:45 p.m. CST on August 26, 2015, C-Dive was working to identify and validate the location for abandonment when the pipeline separated from the mechanical sub-sea fitting, releasing aprroximately 2,631 thousand cubic feet (MCF) of natural gas. This produced a surface fire on the Gulf of Mexico that burned for approximately 2 hours. All facilities in the area were shut-in, allowing the fire to burn out.

At 9:40 p.m. CST on August 26, 2015, Gulf South made an initial notification to the National Response Center (NRC), NRC #1126790, regarding this incident. An update to the original report, NRC #1126839, was filed at 1:27 p.m. CST on August 27, 2015, to address the sheen associated with condesate from the pipeline (Appendix A).

The release occurred approximately 40 miles offshore in approximately 25 feet of water, with no above-water structure that could be affected. The contractors' dive boat was on the surface of the water at the time of the incident, resulting in minor injuries for three contract employees (incurred during the initial response) and negligible fire damage to the boat. After the Bureau of Safety and Environmental Enforcement (BSEE) approved Gulf South's plan, the pipe and fitting was removed and transported to Houma, Louisiana, for initial evauluation. It was then sent to Stress Engineering Services in Houston, Texas, for further testing and evaluation.

System Details

Gulf South is owned by Boardwalk Pipeline Partners, LP. They operate a network of approximately 7,400 miles of gas transmission piplines located in the Gulf Coast States of Texas, Louisiana, Mississippi, Alabama, and Florida. The Lafayette Offshore Unit—the unit affected by this incident—is a system that consists of about 75 miles of pipeline in the Gulf Of Mexico in which natural gas is collected offshore and transported to systems onshore for distribution to end users.

The offshore portion of this system begins in the Eugene Island Block 110 area and terminates onshore in Burns, Louisiana. The 10.75-inch-diameter, 3.33-mile segment (BSEE Segment Number 14162) from Block 110 to Block 95 was being prepared for abandonment under BSEE approval at the time of the incident.

The failure occurred at the sub-sea tie-in assembly area identified in the upper section of the area detail.

[redacted]

Figure 1: Abandonment Area

Pipeline Specifications

The pipe was 10.750-inch-diameter, 0.500-inch wall thickness American Petroleum Institute (API) 5LX-52. The sub-sea connection was an American National Standards Institute (ANSI) 900 compression-type fitting manufactured by HydroTech Systems, Inc., that was designed to connect 10.750-inch-diameter pipe in a subsea environment without welding.

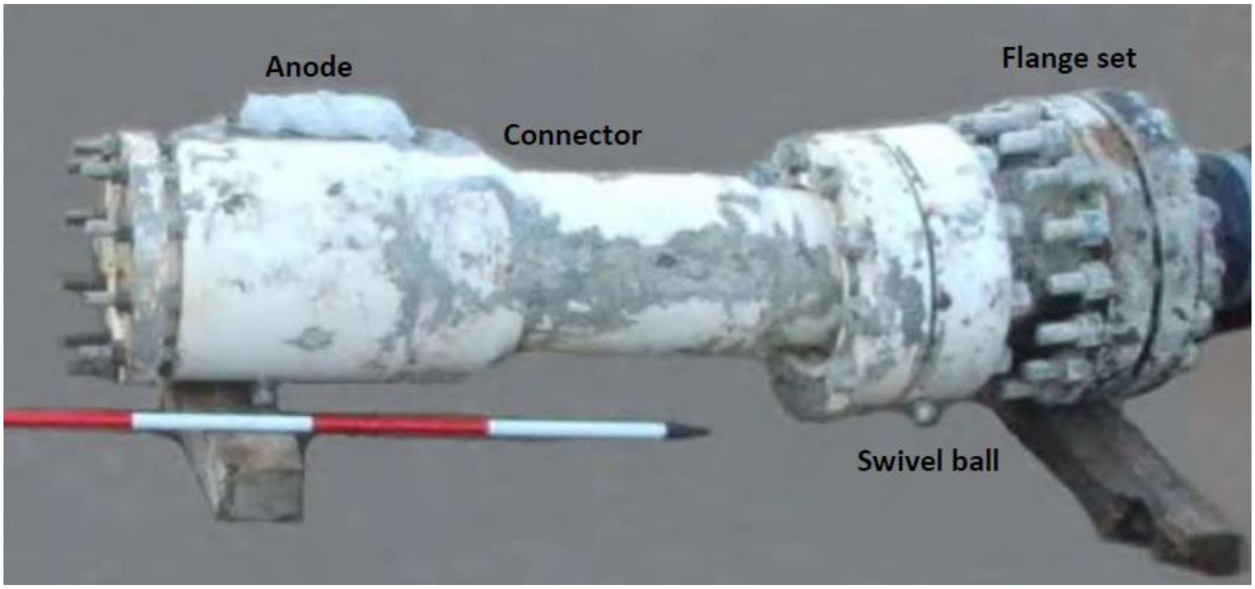

Figure 2: Sub-sea Fitting

The connector was installed in 2006 as an approved repair to damage from Hurricanes Katrina and Rita in 2005.

Events Leading up to the Failure

On August 25, 2015, Gulf South's contractor mobilized on site in preparation for the abandonment of the pipeline system. A crew boat was supplied with diving and jetting equipment, then it and the requisite divers traveled to the appropriate location and anchored in preparation for the abandonment operations. Jetting was being performed to expose the sub-sea isolation valve and connection associated with the shut-in and abandonment. The average water depth on location is 21 feet, and the depth of cover was documented as 7 feet. On August 26, 2015, at 8:45 p.m. on the second day of this operation, when the pipe was exposed and the connection located the pipe dislodged from the mechanical fitting, allowing the pipelines to separate and the incident to occur. It was also noted during this process that an existing stand-off brace had been damaged and dislodged from the pipeline as a result of a previous sub-sea incident. The ensuing incident allowed the 10-inch pipelines to separate and release a full stream of natural gas onto the sea bed. The vapors bubbled to the surface where they ignited, burning until the gas source was isolated. The pipeline was immediately shut-in and the fire allowed to burn out.

Gulf South initially reported the incident to the NRC (#1126790) at approximately 9:43 p.m. CST on August 26, 2015. An updated report was made to the NRC (#1126839) the following day at 2:27 p.m. CST to include the condensate sheen from the release (Appendix A).

Emergency Response

Gulf South responded by immediately isolating the affected systems and allowing the pressure to blow down to atmospheric pressure. The work boat moved off site during this process, and the fire was allowed to burn out. No further actions were required, but the project was shut down pending investigation into the cause of the incident.

The release was located offshore of Lousiana, affecting only a small surface area of the water and the crew boat performing the operation. No emergency response personel were required, and the volume of the gas loss was estimated to be 2.63 million cubic feet (MMCF). A slight sheen from condensate in the system was briefly observed, but quickly dispersed and dissipated.

Summary of Return to Service

Following the emergency response, the pipeline system was isolated and shut-in pendinginvestigation into the cause of the incident. A revised plan, including the removal of the failed mechanical fitting so it could be evaluated, was submitted to BSEE with a new scope for the pipeline system abandonment. Once the new plan was approved, Gulf South mobilized again and completed the removal and abandonment project. The other affected systems shut-in due to the incident were returned to service 11 days later on September 6, 2015.

Investigation Details

At approximately 9:43 p.m. CST on August 26, 2015, Gulf South reported to the NRC a release of natural gas due to an unknown cause at their Eugene Island Block 95 sub-sea connection in the Gulf of Mexico. The Southwest Region division of the Pipeline and Hazardous Materials Safety Administration (PHMSA) received the incident notification and began an investigation the following morning. No response to site was initiated, as the incident was sub-sea. Gulf South coordinated with PHMSA and BSEE regarding the removal of the fitting and its transport to Stress Engineering in Houston, Texas, for evaluation. Upon arrival at Stress, the Southwest Region performed a visual examination of the fitting and a scope for the investigation was established. The primary indication of the failure appeared to be mechanical, and did not indicate any material failure.

Mechanical Analysis

The sub-sea connector was sent to a Houston, Texas, metallurgical lab for analysis, where it was determined that the connector performed as designed and that all damage observed to the connector slips, seals, and pipe occurred during the incident.

Conclusion

Stress Engineering's conclusion was: "the connector fitting likely failed due to a combination of external forces from the pipe being exposed and the lack of support from the damaged stand off found while exposing the pipe." PHMSA concurs with this finding, since this incident occurred sub-sea and site evaluation was limited.

Appendices

A Telephonics Notice Report—NRC #1126839

B Operator Accident Report—ODES #20150114

C Stress Engineering—Document No: 1461154-PL-RP-01 (Rev. 1)

PHMSA Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

Rules of Behavior Home Logout Menu

[Return to Search]

NRC Number: 1126839
Call Date: 08/27/2015 **Call Time:** 14:27:00

Caller Information

First Name: STEPHEN Last Name: BATUK
Company Name: GULF SOUTH PIPELINE COMPANY
Address: 2300 VEROT SCHOOL RD
City: LAFAYETTE State: LA
Country: USA Zip: 70508
Phone 1: 8008500051 Phone 2:
Organization Type: PRIVA Is caller the spiller? Yes No No Response
Confidential: Yes No No Response

Discharger Information

First Name: STEPHEN Last Name: BATUK
Company Name: GULF SOUTH PIPELINE COMPANY
Address: 2300 VEROT SCHOOL RD
City: LAFAYETTE State: LA
Country: USA Zip: 70508
Phone 1: 8008500051 Phone 2:
Organization Type: PRIVA

Spill Information

State: LA County: EUGENE ISLAND AREA
Nearest City: Zip Code:
Location

Spill Date: 08/26/2015 (mm/dd/yyyy) Spill Time: 20:45:00 (24hh:mm:ss)
DTG Type: Select DTG Type
Incident Type Reported Incident Type PIPELINE
Description

///NRC REPORT UPDATE TO REPORT NUMBER 1126790/// THE CALLER IS REPORTING A RELEASE OF NATURAL GAS DUE A SMALL LEAK IN THE PIPELINE LINE. THE CALLER STATED THAT THERE IS A FIRE COMING FROM THE RELEASE SITE. NO REPORTED INJURIES OR EVACUATIONS. DURING AN OVER FLIGHT A SHEEN WAS ALSO OBSERVED ON THE WATER WHICH WAS CREATED BY THE DISCHARGE OF CONDENSATE. THE IMPACT IS THE WATER ATMOSPHERE. THE DAMAGES AMOUNT IS UNKNOWN.

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:

GULF OF MEXICO

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

DIVE BOAT ON SITE. PIPELINE SHUT IN AND SHUT DOWN.

Additional Info

///UPDATE TO NRC REPORT 1126790 TO ADD A MATERIAL TO THE LIST OF MATERIALS DISCHARGED, AS WELL AS TO UPDATE THE INCIDENT SUMMARY AS REQUESTED BY THE RESPONDING COAST GUARD UNIT.

Latitude
Degrees: Minutes: Seconds: Quadrant:
Longitude
Degrees: Minutes: Seconds: Quadrant:
Distance from City: Direction:
Section: Township:
Range: Milepost:

Rescinded Comments (max 250 characters)

<< Previous 1..1 of 1 << 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: 10/31/2017
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	09/18/2015
	No.	20150114 - 17139 (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. All responses to this collection of information are mandatory. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

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	**Yes**

Last Revision Date:	07/08/2016
1. Operator's OPS-issued Operator Identification Number (OPID):	31728
2. Name of Operator	GULF SOUTH PIPELINE COMPANY, LP
3. Address of Operator:	
3a. Street Address	9 GREENWAY PLAZA SUITE 2800
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code:	77046
4. Local time *(24-hr clock)* and date of the Incident:	08/26/2015 20:45
5. Location of Incident:	
Latitude:	29.043056
Longitude:	-91.69944
6. National Response Center Report Number (if applicable):	1126790
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	08/26/2015 21:40
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):	2,631.00
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	08/26/2015 20:45
15b. Local time pipeline/facility restarted	09/06/2015 16:00
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	Yes
17. Did the gas explode?	No
18. Number of general public evacuated:	0
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident– effective 10-2014, changed from "Incident" to "failure"	08/26/2015 20:45
19b. Local time operator resources arrived on site	08/26/2015 23:50

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Incident onshore?	No
- Yes (Complete Questions 2-12)	
- No (Complete Questions 13-15)	
If Onshore:	
2. State:	
3. Zip Code:	
4. City	
5. County or Parish	
6. Operator designated location	
Specify:	
7. Pipeline/Facility name:	
8. Segment name/ID:	
9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)?	
10. Location of Incident :	
11. Area of Incident (as found) :	
Specify:	
Other – Describe:	
Depth-of-Cover (in):	
12. Did Incident occur in a crossing?	
- 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:	25
14. Origin of Incident:	On the Outer Continental Shelf (OCS)
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	Eugene Island
- Block #:	95
15. Area of Incident:	Below water, pipe buried or jetted below seabed

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Offshore Pipeline, Including Riser and Riser Bend
3. Item involved in Incident:	Flange
- If Pipe – Specify:	
3a. Nominal diameter of pipe (in):	
3b. Wall thickness (in):	
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	

3d. Pipe specification:	
3e. Pipe Seam – Specify:	
- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Incident – Specify:	
- 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:	2006
5. Material involved in Incident:	Carbon Steel
- If Material other than Carbon Steel or Plastic – Specify:	
6. Type of Incident involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	Connection Failure
- 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. Class Location of Incident:	Class 1 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:	382
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	$ 625,000
7c. Estimated cost of Operator's emergency response	$ 10,000
7d. Estimated other costs	$ 200,000
Describe:	Investigation
7e. Property damage subtotal (sum of above)	$ 835,000
Cost of Gas Released	
7f. Estimated cost of gas released unintentionally	$ 8,098
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)	$ 8,098
Total of all costs	$ 843,098

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):	925.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	1,200.00
Added 10-2014 2a. MAOP established by 49 CFR section:	192.619(a)(1)
- 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:	Automatic
5b. Type of downstream valve used to initially isolate release source:	Automatic
5c. Length of segment isolated between valves (ft):	174,240
5d. Is the pipeline configured to accommodate internal inspection tools?	No
- 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.)	Yes
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other	Yes
- If Other, Describe:	Sub-sea tie-in
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	Yes
- 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	Yes
- 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?	No
7. How was the Incident initially identified for the Operator?	Notification From Public
- 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)*	Incident occurred while contractor was onsite for scheduled outage performed by area.
- If Yes, Describe 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?	Yes
- If Yes:	
1a. How many were tested:	2
1b. How many failed:	0
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?	Yes
- If Yes:	
2a. How many were tested:	24
2b. How many failed:	0

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 inhibitors 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, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- 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 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, 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, Describe:	
- 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 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:	
- 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:	Miscellaneous
- If Miscellaneous:	
1. Describe:	Dive company was jetting to expose sub-sea tie-in valve assembly for pipeline abandonment. Sub-sea connector

Appendix C

Stress Engineering—Document No: 1461154-PL-RP-01 (Rev. 1)

This document is on file at PHMSA