DOT	US 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	7/ 31/2011
Subject	Failure Investigation Report – Tennessee Gas Pipeline Co. - Internal Corrosion

Operator, Location, & Consequences

Date of Failure	12/08/2010
Commodity Released	Natural Gas
City/County & State	East Bernard/Wharton County, TX
OpID & Operator Name	19160 Tennessee Gas Pipeline Co
Unit # & Unit Name	4084 Cleveland District
SMART Activity #	132408
Milepost / Location	Tennessee Gas Pipeline Co., Station 17, East Bernard, TX
Type of Failure	Internal corrosion in lateral connecting to station discharge header
Fatalities	0
Injuries	0
Description of area impacted	Operator's facility only.
Property Damage	$ 715,000

Executive Summary

On December 8, 2010, Tennessee Gas Pipeline Company made a notification to the National Response Center reporting a natural gas release on their Tennessee Gas Pipeline (TGP) 100 system. Upon review of the information an investigator from the Southwest Region was dispatched to the accident site the following day. At approximately 4:25 pm CST, December 8, 2010, TGP identified a release of natural gas in the discharge header area of the TGP Station 17, System 100, at East Bernard, TX. The failed pipe consisted of 24” diameter, 0.500” wall, X-40(40,000 SMYS) lateral that connected to the station discharge header piping. The TGP system is monitored by gas control in Houston, Texas and the station ESD was activated immediately when the incident occurred. The rupture had occurred in a dead leg of 24’ diameter pipe connecting to the System 100 30” discharge header at the station. There were no fire or injuries associated with this failure, but FM 1162 was closed by local emergency personnel and two residences evacuated as precautionary measures until site was secured. It took 6 hours for the system to completely blow down after which the road was re-opened and the residents returned to their homes.

The station piping MAOP is 750 psig and was operating normally at approximately 720 psig when the failure occurred. A 12 foot section of the ruptured 24” pipe and was ejected 295’ from the origin of the incident. None of the resulting damage from the rupture was outside the perimeter of TGP Station property. It was established that the section of piping that failed was subject to station discharge pressures with no flow during normal operations. It was also on the station facility plan with annual monitoring for dead legs as part of TGP’s overall integrity plan. An estimated 70 mmcf of natural gas was released due to the rupture.

System Details

Tennessee Gas Pipeline Company (TGP) is a subsidiary of El Paso Corporation. Its primary function is transportation of natural gas for industrial and commercial deliveries. TGP provides natural gas from South Texas to the East Coast through various systems that they operate. The failure occurred on the 100 System. The 100 System consist of 4600 miles of multiple pipelines (24" thru 30") running from Texas to West Virginia. See Appendix C for detailed schematics.

This failure occurred in what is known as the Cleveland District unit which consists of a looped pipeline right of way extending 372 miles from valve 13 near Ganado, Texas to valve 36 on the west side of the Toledo Bend reservoir. The pipelines consist mostly of one 24-inch diameter and two 30-inch diameter pipelines that are looped together with crossovers. There are also 12 laterals in sizes ranging from 4 to 20 inch diameter from producing fields that feed gas into the Tennessee Gas pipeline. There are three compressor stations in this inspection unit: East Bernard station (2 turbines); Cleveland station (9 compressors); Jasper station (20 compressors). Each compressor station serves as an operating office for the pipeline.

Figure 1 Tennessee Gas Station #17

Events Leading up to the Failure

The East Bernard Compressor Station 17 has 3 pipelines (24", 26", and 30") entering via a suction header and 3 pipelines (24", 30", and 30") exiting via a discharge header. All systems operate as a single system for gas flow. The systems were flowing gas normally when the rupture occurred with no warning or abnormal situation occurring.

TGP reported the release to the NRC at approximately 5:38 pm CDT on December 8, 2010. (See Appendix A)

Emergency Response

TGP's Station Emergency Shut Down Device (ESD) activated immediately upon line failure and TGP's Control Center isolated and shut in the 100 System from Wharton to Cleveland, pending determination as to the cause of the alarm. Wharton County Sheriff's Department responded, handling the road closure and residential evacuations. No explosion or fire occurred. Approximately 9 miles of 30" pipeline was blown down to secure the location, taking about 6 hours. Residents were then allowed to return home and the road was re-opened.

Summary of Return-to-service

Following the emergency response, TGP isolated Station 17 and stopped all flow of gas in System 100 through the station. Evaluation of the site was performed, complete with a log of debris location from the incident. Above ground piping, affected by the rupture, was visually inspected for external damage from debris that could affect its integrity. A section of ESD piping was damaged and had to be replaced. TGP's initial startup plan only allowed for System 100-1 to free flow gas through the station at a reduced pressure beginning December 12 @ ≈ 1:30 pm.

The operator removed the tee fitting from the header and all piping associated with this dead leg before returning the system to operations.

TGP's return to service plan has all sections of the by-pass piping being evaluated via tethered pig for any other signs of corrosion within the station. The system 100-1 by-pass is currently in service at a reduced pressure, allowing gas to continue free flowing until all station piping is evaluated and repaired. The by-pass flow was then changed over to system 100-3 while 100-1 was evaluated. During this investigation, no other issues or repairs were identified that affect the system MAOP. System was allowed to return to normal service on January 27, 2011.

Investigation Details

At approximately 5:25 pm CST, December 8, 2010, Tennessee Gas Pipeline Co. (TGP) reported to the National Response Center a release of natural gas due a ruptured pipeline within their East Bernard, Texas, and Station 17 site. PHMSA's Southwest Region received the incident notification and made plans to have an investigator on site the next morning. The investigator arrived on site at 7:30 am on December 9th. Site drawings, safety orientation, pipeline specifications and initial findings were reviewed while operator was still preparing to make site safe for entry. Once cleared, the site was entered and the extent of damage was assessed. The operator's written report can be seen in Appendix B.

Figure 2 Failure section

The MAOP of the Station piping is 750 psig and the incident occurred at 720 psig. The incident was a sudden rupture, leaving a 100' X 25' hole around the pipeline and extricating approximately a 12' section of pipe from the ditch. No injuries or fire was associated with this incident and all damages were contained within the station site.

The PHMSA Investigator was able to view the site with the operator. The failure was a full guillotine failure of the pipeline. Photos of the failed section can be seen in Appendix D.

The investigation revealed that the dead leg was established in 2000 when the 24" high pressure Bay City gathering pipeline that fed directly into the East Bernard Station discharge header was sold and disconnected from the TGP system. The disconnect occurred upstream of the mainline valve feeding into the header, establishing approximately 40 feet of isolated pipe without any gas flow. This abandoned connection became a dead leg in the piping at the station and was the point of failure for the rupture. Inspection during the disconnecting process revealed no internal corrosion issues. Since it was a buried segment of pipe it had not been monitored other than at the time of disconnection. All of the above ground dead legs being monitored in the station had not identified any issues with IC, so they had not dug up the below ground sites. After the incident the remaining two (2) underground dead legs were excavated. No IC was present when investigated.

Integrity verification and remediation

TGP performed visual inspections on all the remaining 11 dead legs listed on their "Facility Inspection log" and reviewed the East Bernard station piping to determine if additional locations existed that should be added to the list. No new locations were identified in the process. During the inspection of existing locations, no additional issues were identified. One location on the cooler by-pass that had monitored wall loss, with no growth, was replaced during the inspection.

TGP also reviewed the data as it pertained to the first station downstream of East Bernard. Again, no issues were identified at that station that duplicated the conditions at East Bernard. TGP reviewed their facility inspection plans at other stations for dead leg inspections. They were looking for other similar locations where the same conditions could exist. The review produced no sites of similar conditions.

TGP has a section of their facility inspection plans for monitoring dead legs in their facilities. It is comprehensive with a list of dead legs and complete with monitored results since program initiation. The plans are established and controlled on an area basis. A review of the program did identify some inconsistencies between operating areas, which TGP plans to address.

Metallurgical Analysis
The section of pipe was sent to El Paso's Houston Metallurgical lab for analysis. The conclusions were:

- The failure mechanism that led to the pipeline rupture was identified as internal microbiologically induced corrosion (MIC).
- The severity of the wall loss was greatest in the area which contained the failure origin. A maximum pit depth through the origin measured 0.418 inches which correlates to an 83.6% wall loss based on nominal wall thickness.
- Tensile test, hardness test, chemical analysis, and charpy test results were all typical for pipe of that era. No abnormalities found.

The corrosion integrity analysis performed indicated that the internal corrosion, at its current state, was severe enough to have caused the pipeline to fail at normal operating pressures experienced by Station 17. The complete report is included in Appendix E.

Findings and Contributing Factors

The rupture occurred at approximately 4:25 pm on December 8, 2010. TGP's Control Center took immediate actions to ESD Station 17 and isolate the piping associated with the rupture. The local station crew was still on site and secured the area. The discovery and isolation was prompt and operator's actions appear to be appropriate.

The failure initiated from a section of dead leg piping established in 2000 when a 24" lateral was disconnected from the stations downstream header. There were obvious indications of residual moisture gathering in the dead leg, contributing to internal corrosion and a thinning of the pipe wall. The internal corrosion was caused by microbiological organisms present due to free moisture in the pipe. Evaluation of all other dead leg segments of pipe in the Station yard found no additional areas affected.

Appendices

A Telephonic Notice Report – NRC #961743
B Written Accident Report 20110002
C Operator Piping Schematic
D Failure Site Photos
E Metallugical Lab Report

Appendix A

NRC # 961743 report is forwarded for your situational awareness. CMC 6-1863

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

Incident Report # 961743

INCIDENT DESCRIPTION

*Report taken by: PO2 BRIAN DOVE at 18:40 on 08-DEC-10
Incident Type: PIPELINE
Incident Cause: OTHER
Affected Area:
Incident occurred on 08-DEC-10 at 16:25 local incident time.
Affected Medium: AIR   ATMOSPHERE

REPORTING PARTY
Name: KENNETH PETERS
Organization: TENNESSEE GAS PIPELINE
Address: 569 BROOKWOOD VILLAGE
BIRMINGHAM, AL 35209
TENNESSEE GAS PIPELINE reported for the responsible party.
PRIMARY Phone: (205)8076163
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY
Name: KENNETH PETERS
Organization: TENNESSEE GAS PIPELINE
Address: 569 BROOKWOOD VILLAGE
BIRMINGHAM, AL 35209
PRIMARY Phone: (205)8076163

INCIDENT LOCATION
22480 FM 1164 RD   County: WHARTON
City: EAST BERNARD   State: TX

RELEASED MATERIAL(S)
CHRIS Code: ONG   Official Material Name: NATURAL GAS
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A RUPTURE AND RELEASE OF GAS FROM A PIPELINE IN THE COMPRESSOR STATION YARD, THE EXACT CAUSE IS UNKNOWN AT THIS TIME. THERE HAVE BEEN 2 HOMES EVACUATED.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO   Fire Extinguished: UNKNOWN

INJURIES: NO   Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO   Empl/Crew: Passenger: Occupant:
EVACUATIONS:YES   Who Evacuated:PRIVATE CITIZENS   Radius/Area:
Damages: NO

Closure Type		Description of Closure	Hours Closed	Direction of Closure
Air:	N			
Road:	Y	FM 1164	ALL	Major Artery:N
Waterway:	N			
Track:	N			

Environmental Impact: NO
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

PIPELINE IS BEING SHUT IN. THE LINE IS EXPECTED TO CONTINUE TO RELEASE FOR 6 MORE HOURS.
Release Secured: NO
Release Rate:
Estimated Release Duration:

WEATHER

Weather: CLEAR, 50ºF

ADDITIONAL AGENCIES NOTIFIED
Federal: NONE
State/Local: STATE ENVIRONMENTAL, LOCAL SHERIFF
State/Local On Scene: LOCAL SHERIFF
State Agency Number: NONE

NOTIFICATIONS BY NRC
CALCASIEU PARISH SHERIFF'S DEPT (CRIMINAL INTELLIGENCE UNIT)
08-DEC-10 18:46 (337)4913778
USCG ICC (ICC ONI)
08-DEC-10 18:46 (301)6693363
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
08-DEC-10 18:46 (202)3661863
EPA OEM (MAIN OFFICE)
(202)5643850
EPA OEM (AFTER HOURS SECONDARY)
(202)5643850
U.S. EPA VI (MAIN OFFICE)
(866)3727745
FEDERAL EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
08-DEC-10 18:46 (800)6347084
USCG NATIONAL COMMAND CENTER (MAIN OFFICE)
(202)3722100
JFO-LA (COMMAND CENTER)
08-DEC-10 18:46 (225)3366513
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
08-DEC-10 18:46 (202)2829201
NOAA RPTS FOR TX (MAIN OFFICE)
08-DEC-10 18:46 (206)5264911
NATIONAL RESPONSE CENTER HQ (MAIN OFFICE)
(202)2671136
HOMELAND SEC COORDINATION CENTER (MAIN OFFICE)
08-DEC-10 18:46 (202)2828300
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
08-DEC-10 18:46 (202)3660568
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VER
(202)3661863
TCEQ (MAIN OFFICE)
08-DEC-10 18:46 (512)2392507
TEXAS STATE OPERATIONS CENTER (COMMAND CENTER)
08-DEC-10 18:46 (512)4242208

ADDITIONAL INFORMATION
CALLER HAD NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT #961743 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

Appendix B

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: 01/31/2013

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	01/06/2011
	No.	20110002 - 15289 (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.*

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	07/05/2011
1. Operator's OPS-issued Operator Identification Number (OPID):	19160
2. Name of Operator	TENNESSEE GAS PIPELINE CO (EL PASO)
3. Address of Operator:	
3a. Street Address	569 Brookwood center, Suite 501
3b. City	BIRMINGHAM
3c. State	Alabama
3d. Zip Code:	35209
4. Local time *(24-hr clock)* and date of the Incident:	12/08/2010 16:25
5. Location of Incident:	
Latitude:	29.531381
Longitude:	-96.1425
6. National Response Center Report Number (if applicable):	961743
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	12/08/2010 17:38
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):	69,908.00
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	12/08/2010 16:25
15b. Local time pipeline/facility restarted	01/27/2011 15:45
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	2
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	12/08/2010 16:25
19b. Local time operator resources arrived on site	12/08/2010 16:25

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:	77435-9487
4. City	East Bernard
5. County or Parish	Wharton
6. Operator designated location	Milepost/Valve Station
Specify:	0
7. Pipeline/Facility name:	East Bernard Station 17
8. Segment name/ID:	High Pressure Gas Gathering Header
9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Incident :	Operator-controlled property
11. Area of Incident (as found) :	Underground
Specify:	Under soil
Other – Describe:	
Depth-of-Cover (in):	39
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 Body
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.5
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	40,000
3d. Pipe specification:	API 5L or equivalent
3e. Pipe Seam – Specify:	Other

- If Other, Describe:	Unknown.
3f. Pipe manufacturer:	A.O. Smith
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 Steel or Plastic – Specify:	
6. Type of Incident involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other – Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other – Describe:	
Approx. size: in. (widest opening):	24
by in. (length circumferentially or axially):	141
- 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:	454
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 cost to Operator :	
7a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$ 0
7b. Estimated cost of gas released unintentionally	$ 600,000
7c. Estimated cost of gas released during intentional and controlled blowdown	$ 0
7d. Estimated cost of Operator's property damage & repairs	$ 110,000
7e. Estimated cost of Operator's emergency response	$ 5,000
7f. Estimated other costs	$ 0
Describe:	
7g. Estimated total costs (sum of above)	$ 715,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	717.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	750.00
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. - 5f. 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):	46,780
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.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other	Yes
- If Other, Describe:	Segment containing failure is a capped "stub" of pipe thus rendering a configuration that does not accommodate an internal inspection tool.
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?	Local Operating Personnel, including contractors
- 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 the following:	Operator employee
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)*	Operating pressures were in normal range.
- 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?	No
- If Yes:	
1a. Describe how many were tested:	
1b. Describe 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. Describe how many were tested:	
2b. Describe 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:	G1 - Corrosion Failure

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

Corrosion Failure – Sub-cause:	Internal Corrosion
- 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:	Other
- If Other, Describe:	MIC deteriorating the inside wall of the pipe.
7. Cause 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	
- Elbow	
- Drop-out	
- Other	Yes
- If Other, Describe:	Dead end (weld cap).
10. Was the gas/fluid 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 Pipeline
13. Were corrosion coupons routinely utilized?	No
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?	No
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?	No
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. 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 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?	No
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 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 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 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 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 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 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

- 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-case 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)*	
- If 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)*	
- If 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 Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Compressor), Vessel 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 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 Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage:	
- If Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure:	
1. Specify:	
- If Other, Describe:	
- If Valve Left or Placed in Wrong Position, but NOT Resulting in an Overpressure:	
- If Pipeline or Equipment Overpressured:	
- If Equipment Not Installed Properly:	
- If Wrong Equipment Specified or Installed:	
- 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:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART - H NARRATIVE DESCRIPTION OF THE INCIDENT

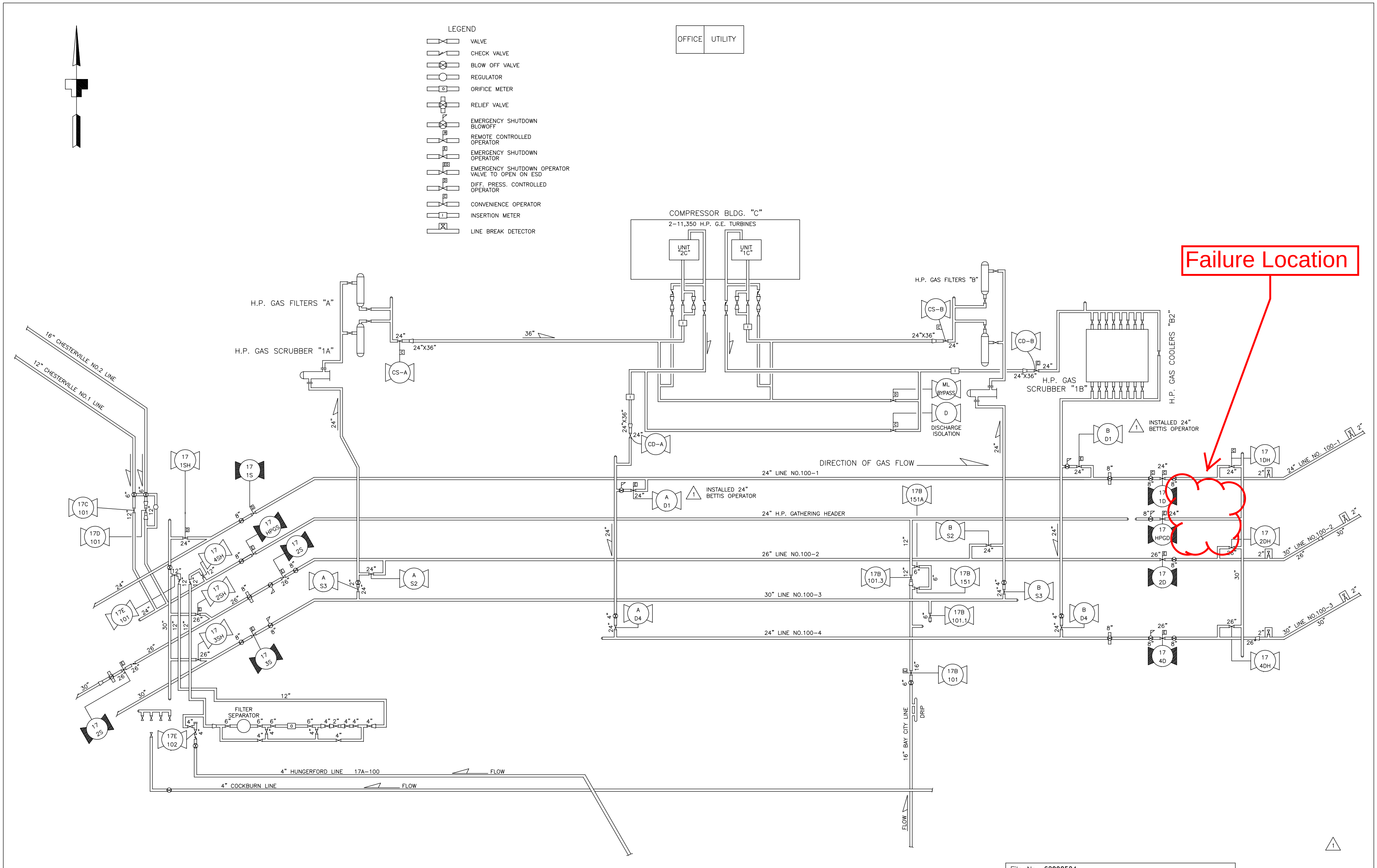
On December 8, 2010, Tennessee Gas Pipeline (TGP) operations personnel at the company's East Bernard Compressor Station (Station 17) heard a loud noise approximately 1,100 feet south of their location. TGP Gas Control observed a corresponding pressure drop in the pipeline near the station. A 24-inch pipe had ruptured without gas ignition. The cause has been determined to be internal corrosion.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Kenneth C Peters
Preparer's Title	Manager - DOT Compliance Field Support
Preparer's Telephone Number	2053257554
Preparer's E-mail Address	ken.peters@elpaso.com
Preparer's Facsimile Number	2053253729
Authorized Signature's Name	Kenneth C Peters
Authorized Signature Title	Manager - DOT Compliance Field Support
Authorized Signature Telephone Number	2053257554
Authorized Signature Email	ken.peters@elpaso.com
Date	07/05/2011

Appendix C



REFERENCE DRAWINGS			
DRAWING NO.	TITLE	DRAWING NO.	TITLE

REVISIONS						
NO.	DATE	REMARKS	REV.	CKD.	COR.	APP.
1	3/04	INSTALLED TWO 24" BETTIS OPERATORS	KW	RAH		FB

TENNESSEE GAS PIPELINE
an El Paso Energy company
Engineering Department
Houston, Texas

DRAWN BY MP DATE 9-11-97
CHECKED BY DATE
DRAFTING COORD. DATE
SUPERVISOR DATE
DESIGN COORD. DATE
DISCIPLINE ENGR. DATE
PROJECT ENGR. DATE
ISSUE DATES ORIGINAL 7-24-92 LAST

File No.: 62990524

SCHEMATIC OF H.P. GAS PIPING
STATION NO. 17
WHARTON COUNTY, TEXAS

APPROVED BY
DATE: MANAGER
Tennessee Gas Pipeline Co.
TO-C17-E1X-Y-101

TGPUS-0000001
(12/08/10 Station 17 Rupture)

Appendix D

TENNESSEE GAS PIPELINE-EAST BERNARD INCIDENT
PHMSA

Pipeline and Hazardous Materials Safety Administration

DRAFT
FOR OFFICIAL USE ONLY


Figure D1 - Rupture Location


Figure D2 – End of Rupture Location


Figure D3 – End of Rupture Location


Figure D4 – Internal surface of pipe

Appendix E Metallurgical Lab Report

This document is on file at PHMSA