Failure Investigation Report – Williams (Transco) Corrosion Failure
April 26, 2010

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

Principal Investigator	Jon Manning
Region Director	R.M. Seeley
Date of Report	3/31/2011
Subject	Failure Investigation Report – Williams (Transco) Corrosion Failure

Operator, Location, & Consequences

Date of Failure	4/26/2010
Commodity Released	Natural Gas
City/County & State	Kleberg County, TX - near Kingsville
OpID & Operator Name	19570 Williams Gas Pipeline - Transco
Unit # & Unit Name	13314 Transco South Texas District
SMART Activity #	129876
Milepost / Location	Milepost 97.53
Type of Failure	Leak caused by External Corrosion
Fatalities	0
Injuries	0
Description of area impacted	Ranch Property
Property Damage	$57,084

Executive Summary

On April 26, 2010, Williams Gas Pipelines – Transco (Transco, the Operator) reported to the NRC (No. 938267) a leak on their 24-inch "A Pipeline" near Kingsville, TX. A pipeline technician assigned to take annual cathodic protection readings initially observed bubbles in standing water on the pipeline right-of-way on April 22, 2010. The area is crisscrossed with crude oil gathering pipelines and Operator personnel were initially unsure that the release was from the Transco pipeline. After discovery, production supplying the "A Pipeline" was shut-in and the valve segment isolated. Excavation revealed that the release was occurring from a small external corrosion anomaly located on the pipeline at approximately the 5 o'clock position. Additional isolated corrosion pits in the segment near the leak site required the Operator to replace approximately 30 feet of 24-inch pipe to accomplish the repair.

The metallurgical evaluation performed by Stork Testing and Metallurgical Consulting determined the probable cause of failure to be Microbiologically-influenced Corrosion (MIC). The metallurgical analysis also indicated that the coal tar coating near the leak was degraded, and may have been damaged by hydrocarbon liquids leaking from a deteriorated gathering pipeline that crossed above the Transco pipeline. The leaking hydrocarbons would have also created an environment conducive to the growth of sulfate reducing bacteria.

The Operator recently changed the cathodic protection on this segment from using the -850mV with consideration for IR drop to the 100 mV depolarization criterion. A close-interval survey (CIS) performed in 2009 did not indicate any areas where the 100mV criterion was not being met. While MIC is a different failure mechanism than traditional electrochemical corrosion, research by T. Barlo and W. Berry at Battelle Columbus Laboratories in 1984 concluded that 200 to 300 mV of polarization may protect carbon steel from corrosion caused by sulfate reducing bacteria. Subsequent studies have determined that higher polarization potentials may be required to accomplish this protection depending on the specific environment around the pipeline. While there was no indication that Transco was not meeting one of the required cathodic protection requirements of Part 192, the level of cathodic protection potentials maintained on the "A Pipeline" apparently were not adequate to inhibit MIC.

System Description

Williams Gas Pipeline Company (WGP) is an interstate pipeline operator that is comprised of three pipeline systems – Northwest Pipeline, Transco, and Gulfstream. The Transco system consists of approximately 9,000 miles of DOT jurisdictional pipeline in Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, New Jersey, New York, and Pennsylvania. Transco transports natural gas from the Gulf Coast to the northeast and southeast states.

The 24-inch pipeline was constructed in 1949 and is 0.281-inch wall, 24-inch ERW pipeline with a Specified Minimum Yield Strength (SMYS) of 52,000 psig. The MAOP on the pipeline is 877 psig. The pipeline is coated with coal tar enamel.

Incident Description

On April 26, 2010, Williams Gas Pipelines – Transco (Transco, the Operator) reported to the National Response Center (NRC) a leak on their 24-inch "A Pipeline" on King Ranch property near Kingsville, TX. (See Appendix A). PHMSA responded to the incident by conducting an onsite investigation. PHMSA investigators arrived on site April 28, 2010.

The incident occurred at approximate Milepost (MP) 97.53. The pipeline is included in the Transco South District inspection unit and runs from the DCP La Gloria processing plant near Falfurrias, TX at MP 78.85 northeast to the Lavaca River at MP 178.88.

Operating Conditions Prior to Incident

On April 22, 2010 the Transco "A Pipeline" was operating normally when bubbles were observed by a technician in standing water above the pipeline near MP 97.457 on property owned by King Ranch. The pressure at the leak site was estimated to be approximately 560 psig and transporting approximately 64 MMcfd when the leak was discovered. The MAOP of the system is 877 psig.

Investigation and Operating Conditions After the Incident

A pipeline technician assigned to take annual cathodic protection readings observed bubbles in standing water on the pipeline right-of-way on April 22, 2010. Transco responded to the potential leak by shutting-in and isolating the pipeline valve segment. The area is crisscrossed with small diameter gathering pipelines making the Operator initially unsure that the release was from the Transco pipeline. Pressure monitoring was inconclusive so the Operator decided to excavate to confirm the source of the leak.

Excavation of the pipeline was delayed by the permitting process required by the King Ranch. The leak was visually confirmed on April 26 and telephonically reported at 8:08 PM that evening. Excavation of the pipeline revealed that the release was occurring from a small (less than ¼-inch in diameter) external corrosion anomaly at approximately the 5 o'clock position. After confirmation, production supplying the pipeline was shut-in, the pipeline was taken out of service, and the valve segment isolated and blown down. The coating was removed on both sides of the leak site and additional isolated corrosion pits were found.

The Operator replaced approximately 30 feet of 24-inch pipe to make the repair. The pipeline was returned to service on April 29, 2010 at approximately 11:00 AM. The Operator's investigation and analysis of the incident is documented in a report titled "WGP Incident Root Cause Analysis," and is included in Appendix B.

The area on King Ranch where the leak occurred is crisscrossed by several crude oil gathering pipelines, most of which are operated by ExxonMobil. These unregulated pipelines are old, not well marked, not mapped, and are not cathodically protected. Transco personnel reported a strong hydrocarbon smell in the area and initially suspected the leak was from one of the gathering pipelines. However, the Transco release was visually confirmed when the pipe was excavated.

The cause of failure was determined to be MIC, and according to the Operator there were no prior indications of MIC on this pipeline segment. While MIC is a different failure mechanism than traditional electrochemical corrosion, the Operator's cathodic protection records were reviewed to determine if there were any indications of other external corrosion issues on this pipeline. There were no previous external corrosion related repairs on the failed valve segment and recent annual survey readings did not indicate cathodic protection deficiencies in the area of the leak. Transco records indicate that a close interval survey (CIS) was performed in 2009 and afterwards the Operator began using the 100 mV depolarization criterion on this valve segment. The CIS did not identify any areas on the valve segment not meeting the 100 mV depolarization criterion. At the leak location the CIS showed an "on" potential of approximately -1,231 mV, a polarized potential of approximately -808 mV, and polarization of approximately 555 mV.

Transco operates a rectifier and ground bed approximately ¼ mile upstream of the leak site. The Operator recently equipped all of the rectifiers on this valve segment with satellite synchronized interrupters that include remote monitoring capability. The system is designed so that the corrosion technician automatically receives electronic notification if an operational problem is detected with a rectifier on this segment. There were no indications of a problem with the protection system.

During the repair of the pipeline a significant quantity of black powder was found on the inside of the pipeline. Black powder may be an indication of internal corrosion as it is a form of iron oxide. During the investigation PHMSA reviewed the SCADA information. Pressure monitoring was inconclusive at the time of the leak so the Operator decided to excavate to confirm the source of the leak. A subsequent review of the data after the failure was also inconclusive. Typically, small leaks of this type are difficult to detect through normal SCADA monitoring.

The aerial patrol performed on April 21, 2010 did not report the leak. Transco personnel stated the size of the leak made it difficult to visually detect from the air and the standing water on the pipeline right of way from the rain was reported to have occurred after the flight. The leak was not in an area determined by the Operator to be a Part 192 High Consequence Area (HCA).

There was no ILI data to review. The “A Pipeline” cannot be pigged due to the design of the mainline valves. The operator plans to replace the valves in 2011 so that the pipeline can be maintenance pigged and ILI’s can be performed to assess the integrity of the pipeline.

Metallurgical Analysis

The failed pipeline segment was sent to Stork Testing & Metallurgical Consulting, Inc. (Stork) of Houston, TX for metallurgical analysis. Stork determined that the probable cause of failure was from microbiologically-influenced corrosion (MIC). The metallurgical analysis also indicated that the coal tar coating near the leak was degraded, and was likely due to a substance leaking from a deteriorated gathering pipeline that crossed the Transco pipeline above the area of the leak. This also likely created an environment conducive to the growth of sulfate reducing bacteria. The PHMSA 7100.2 Incident Report is included in Appendix C and the Stork Metallurgical Analysis Report is included in Appendix D.

Findings

1. The “A Pipeline” was leaking from a small corrosion anomaly (approximately ¼ inch diameter) at approximately the 5 o’clock position on the pipeline.

2. With the exception of the area around the leak, the coating appeared to be intact.

3. The process of obtaining permission and permits to excavate on the King Ranch property resulted in the time delay between the initial discovery on April 22 and confirmation on April 26. The telephonic report was made by the Operator after confirmation.

4. At the time of the discovery, the Transco 24-inch pipeline was operating at approximately 560 psig and transporting approximately 64 Mmcfd. The MAOP on the pipeline is 877 psig.

5. An In-line Inspection (ILI) has not been performed on this section of the "A Pipeline" due to the design of the mainline valves. The pipeline has not had any previously reported failures due to corrosion.

6. The Operator committed to further investigate the black powder substance found inside the pipe at the failure site.

Conclusions

1. Microbiological-influenced Corrosion (MIC) was determined to be the probable cause of failure.

2. The operator took reasonable actions to confirm the source of the leak which resulted in a time lapse between initial discovery and the telephonic reporting.

Appendices

Appendix A – Telephonic Notice Report (NRC 938267)

Appendix B – WGP Incident Root Cause Analysis

Appendix C – PHMSA 7100.2 Incident Report

Appendix D – Metallurgical Analysis Report

Appendix E - Photographs

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

Incident Report # 938267

INCIDENT DESCRIPTION

*Report taken at 20:41 on 26-APR-10
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident was discovered on 26-APR-10 at 18:08 local time.
Affected Medium: AIR

SUSPECTED RESPONSIBLE PARTY

Organization: WILLIAMS GAS PIPELINE TRANSCO
HOUSTON, TX 77056

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

County: KLEBERG
City: KINGSVILLE State: TX
Distance from City: 12 MILES
Direction from City: W

12 MILES WEST OF KINGSVILLE, TX / PIPELINE MILE 97.530

RELEASED MATERIAL(S)

CHRIS Code: ONG Official Material Name: NATURAL GAS
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

A LEAK WAS DISCOVERED ON A 24" PIPELINE. THE CAUSE IS UNKNOWN AT THIS TIME.

INCIDENT DETAILS

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

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN

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

Closure Type		Description of Closure	Length of Closure	Direction of Closure		
Air:	N					
Road:	N				Major Artery:	N
Waterway:	N					
Track:	N					

Passengers Transferred: NO

Environmental Impact: UNKNOWN

Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

LINE ISOLATED

Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: CLEAR, ºF

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: NONE
State/Local On Scene: NONE
State Agency Number: NONE

NOTIFICATIONS BY NRC

USCG ICC (ICC ONI)
26-APR-10 20:46
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
26-APR-10 20:46
U.S. EPA VI (MAIN OFFICE)
26-APR-10 20:58
JFO-LA (COMMAND CENTER)
26-APR-10 20:46
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
26-APR-10 20:46
NOAA RPTS FOR TX (MAIN OFFICE)
26-APR-10 20:46
TCEQ (MAIN OFFICE)
26-APR-10 20:46
TX GENERAL LAND OFFICE (TXGLO REGION 3)
26-APR-10 20:46
TEXAS STATE OPERATIONS CENTER (COMMAND CENTER)
26-APR-10 20:46

ADDITIONAL INFORMATION

CALLER HAD NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT # 938267 ***

Appendix B – WGP Incident Root Cause Analysis

This document is on file at PHMSA

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:**	05/13/2010
	No.	20100023 - 15038 (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. Public reporting for this collection of information is estimated to be approximately 10 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this 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.*

PART A - KEY REPORT INFORMATION

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

Report Status:	Submitted
Create Date:	06/04/2010
1. Operator's OPS-issued Operator Identification Number (OPID):	19570
2. Name of Operator	WILLIAMS GAS PIPELINE - TRANSCO
3. Address of Operator:	
3a. Street Address	2800 POST OAK BOULEVARD
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code:	77056
4. Local time *(24-hr clock)* and date of the Incident:	04/26/2010 06:08
5. Location of Incident:	
Latitude:	27.51171
Longitude:	-97.9847
6. National Response Center Report Number (if applicable):	938267
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	04/26/2010 09:00
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):	4.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	6,819.00
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	04/26/2010 07:15
15b. Local time pipeline/facility restarted	04/29/2010 11:05
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
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	04/26/2010 06:15
19b. Local time operator resources arrived on site	04/26/2010 07:15

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:	78363
4. City	Kingsville
5. County or Parish	Kleberg
6. Operator designated location	Milepost/Valve Station
Specify:	97.457
7. Pipeline/Facility name:	MAINLINE A
8. Segment name/ID:	
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):	65
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):	.281
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	52,000
3d. Pipe specification:	TGTC-1A

3e. Pipe Seam – Specify:	DSAW
- If Other, Describe:	
3f. Pipe manufacturer:	Consolidated Western
3g. Year of manufacture:	1950
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:	
5. Material involved in Incident:	Carbon Steel
- If Material other than Steel or Plastic – Specify:	
6. Type of Incident involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	Pinhole
- 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:	491
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	$ 5,000
7b. Estimated cost of gas released unintentionally	$ 15
7c. Estimated cost of gas released during intentional and controlled blowdown	$ 26,069
7d. Estimated cost of Operator's property damage & repairs	$ 25,000
7e. Estimated cost of Operator's emergency response	$ 1,000
7f. Estimated other costs	$ 0
Describe:	
7g. Estimated total costs (sum of above)	$ 57,084

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	518.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	878.00
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):	53,118
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	Yes
- 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?	No
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?	Ground Patrol by Operator or its contractor
- 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)*	Incident was material failure.
- 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:	External Corrosion
- If External Corrosion:	
1. Results of visual examination:	Localized Pitting
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	Yes
- 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	Yes
- Determined by metallurgical analysis	
- Other	
- If Other – Describe:	
4. Was the failed item buried under the ground?	Yes
- If Yes:	
4a. Was failed item considered to be under cathodic protection at the time of the incident?	Yes
- If Yes, Year protection started:	1950
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	Yes
4c. Has one or more Cathodic Protection Survey been conducted at the point of the incident?	Yes
If "Yes, CP Annual Survey" – Most recent year conducted:	2009
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?	Yes

- 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?	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

A call from a Williams employee was received at 6:15PM stating that a leak on 24" Mainline A has been discovered. After having notified Gas Control in Houston, several South Texas District employees were contacted and requested that they close both Block Valves 10-A-70 and 10-A 80, which would isolate the section of pipeline where the leak was located. The pipeline was isolated and had been made secure by 7:15 PM. NRC was contacted at 7:37 PM and any other agencies that would normally be included in the notification process. These notifications were completed by 8:00 PM that evening..

A Gas Handling Plan and a Work Plan were generated early on Tuesday morning and the section of pipeline between the two block valve settings was blown down. A contractor was dispatched to the location and once the pipeline was made safe, started excavating the line to expose the area of the leak. During the excavation process, an old and mostly corroded 2" pipeline which was already in pieces was uncovered. This 2" pipeline was located approximately 2 ½" above our 24" pipeline. This 2" pipe was abandoned and been out of service for some time. The soil around the 2" pipeline and down to our pinhole leak was saturated with some type of product that smelled very much like condensate. The pinhole leak was located and after close inspection, a 30' section of pipe was cut out and replaced with new pretested pipe. The original 24" pipe at both ends of the 30' section was in excellent condition both internally and externally. Soil samples were taken of the immediate area and were shipped overnight to a lab for further analysis. Williams had a metallurgical test of the pipe that was cut out in order that it can identify the Root Cause of the corrosion at that particular site.

The 24" pipeline was purged, packed and placed back in service at 11:00 AM on Thursday, April 29th, 2010.

Metallurgical analysis confirmed that the reason for the leas was Microbiological on 6/2/2010. The Metallurgical report found the following;

The coal tar corrosion protection that coated the pipeline when it was originally installed had been severely degraded in the area around the leak, probably by a chemical substance that had apparently leaked from the 2-inch pipeline installed over the 24-inch line.

Visual examination of the leak showed corrosion pitting on the outside surface. Some of the pits had a fibrous appearance indicating preferential attack following the pipe axis. The fibrous appearance was characteristic of microbiologically-influenced corrosion (MIC).

Metallographic analysis of the corrosion pits showed undercutting and pits within pits, which are also unique characteristics of MIC.

The leak was caused by MIC, which occured after the coal tar coating had been degraded exposing the bare pipe. The presence of sulfur and moisture in the soil around the leak created an ideal environment for MIC to occur.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Edgar Rodriguez
Preparer's Title	Pipeline Safety Specialist II
Preparer's Telephone Number	7132152846

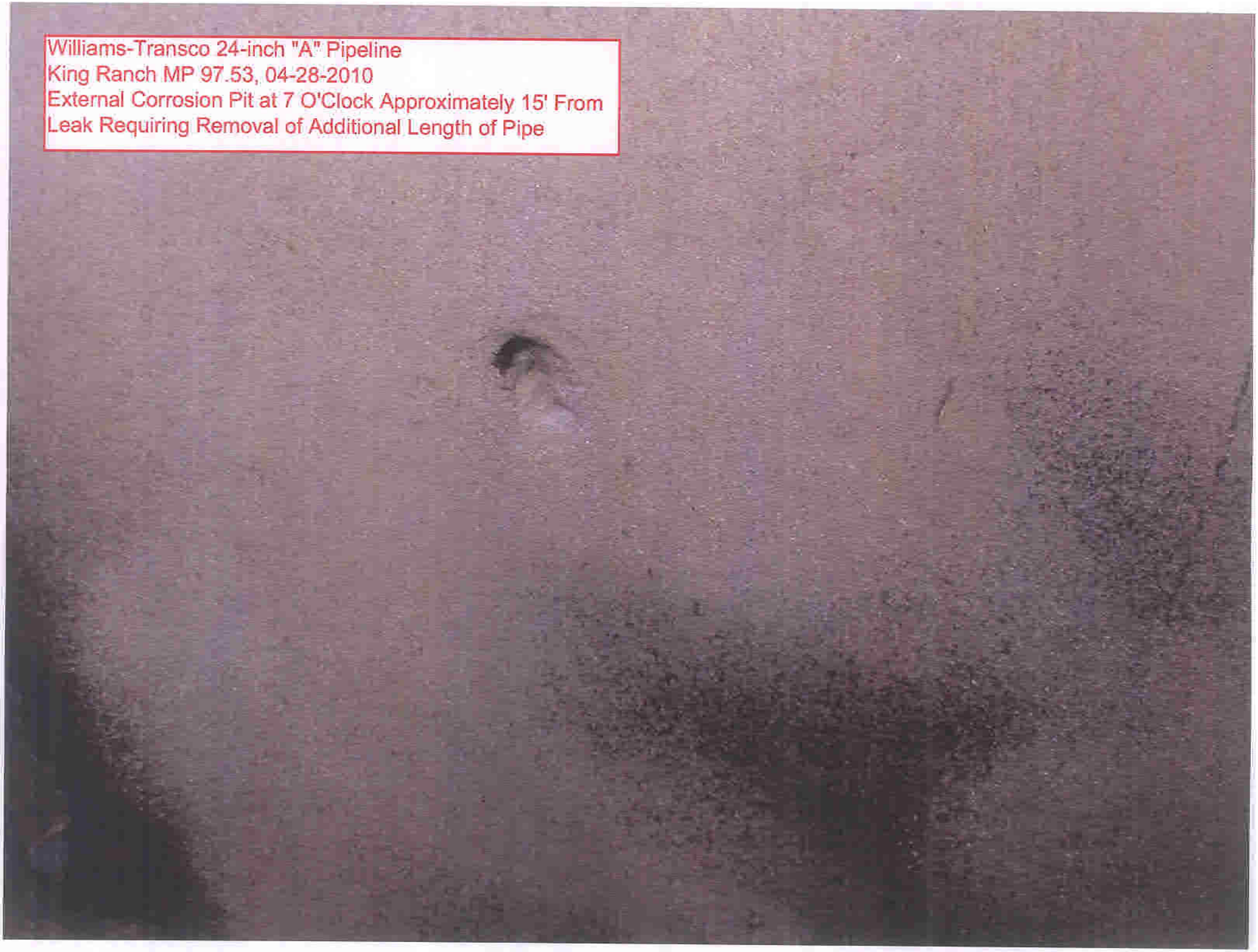
Preparer's E-mail Address	edgar.x.rodriguez@williams.com
Preparer's Facsimile Number	7132152222
Authorized Signature's Name	Marie Sotak
Authorized Signature Title	Pipeline Safety Manager
Authorized Signature Telephone Number	7132152111
Authorized Signature Email	marie.sotak@williams.com
Date	06/25/2010

Appendix D – Metallurgical Analysis Report

This document is on file at PHMSA


Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-26-2010
Bubbles in Standing Water on ROW

Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
External Corrosion Anomaly



Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
External Corrosion Pit at 7 O'Clock Approximately 15' From
Leak Requiring Removal of Additional Length of Pipe


Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Abandoned Crude Oil Gathering Line Removed Near
External Corrosion Release


Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
External Pipe Surface Near External
Corrosion Anomaly

Williams-Transco 24-inch "A" Pipeline
King Ranch MP97.53, 04-28-2010
Excavation of External Corrosion Anomaly
Examination of Pipe on Both Sides of External Corrosion Anomaly Required Replacement of Approximately 30' of Pipe

Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Contractor Preparing to Cold-Cut Pipe

Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Cold-Cutting 24-inch Pipe
Note: Bonding Cable Attached to Equalize
Electrical Potentials on Each Side of Cut

Williams-Tranco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Approximately 30' of 24-inch Pipe Removed


Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Pipe Segment Removed Due to External
Corrosion Pitting (Approximately 30')


Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Re-testing for Hazardous Environment


Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Residue Found Inside of Pipeline During Replacement of 30'
Pipe Segment Due to External Corrosion

Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Residue Removed from Inside of Pipeline During
Replacement of 30' Pipe Segment Due to External Corrosion

Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 4-28-2010
Black Residue Inside Pipe During Replacement of
30' Segment Due to External Corrosion

Williams-Transco 24-inch "A" Pipeline
King Ranch MP 97.53, 04-28-2010
Pre-tested Replacement Pipe
Note: Poor Coating Condition Required Surface Preparation and Re-Coating with Denso Protal