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

Principal Investigator	David Eng
Region Director	Rod Seeley
Date of Report	10/01/2013
Subject	Failure Investigation Report – Denbury Green

Operator, Location, & Consequences

Date of Failures	12/20/2010 and 02/14/2011
Commodity Released	CO2
City/County & State	Kinder/Allen Parrish, LA (2010 release) Beaumont/Jefferson County, TX (2011 release)
OpID & Operator Name	32545 Denbury Gulf Coast Pipelines, LLC
Unit # & Unit Name	72836 Delta and Green – Louisiana Pipelines
SMART Activity #	132719
Milepost / Location	Survey Station 7883+78 (2010 release) Milepost 229.5 (2011 release)
Type of Failure	Small seam weld penetrators from manufacture of the pipe
Fatalities	None
Injuries	None
Description of Area Impacted	Non-HCA, uninhabited remote locations
Property Damage	None

Executive Summary

Denbury Gulf Coast Pipelines, LLC (Denbury) experienced two leaks on their CO_2 “Green Line” in a 3-month time period between December 2010 and February 2011. The Denbury Green Pipeline is a 237.3 mile (approximate), 24-inch interstate pipeline designed to transport carbon dioxide from a location near Donaldsonville, LA, to the Hastings field south of Houston, TX. The first leak occurred on December 20, 2010, and the second occurred on February 14, 2011.

PHMSA did not initiate an accident response at the time of either of the releases; however, an investigation was initiated at the time of the metallurgical examinations of the failed pipe specimens in 2011. Both failures were attributable to a single common element: welding imperfections occurring in the long seam of the pipe during the manufacture of the pipe joint at the pipe mill (“penetrators”).

The failures occurred in rural, uninhabited (non-High Consequence Areas (HCA)) areas. Emergency responses were initiated for both incidents and resulted in no fatalities, no injuries, no property damage or HCAs being affected. The results from the investigation, as well as successive annual foot patrols of the line, suggest the remainder of the line does not contain any similar flaws.

System Details

At the time of the failures, the pipeline was operated under one operator identification number: Denbury Gulf Coast Pipelines, LLC. Shortly after the failures, and during the PHMSA investigation, the Denbury Green Pipeline was divided between Denbury Gulf Coast Pipeline, LLC, and Denbury Green Pipeline – Texas, LLC. The Denbury Green Pipeline is an onshore interstate liquids system traversing the states of Louisiana and Texas. The sole commodity transported is CO_2 (see Appendix A).

The Denbury Green Pipeline is a 237.3 mile (approximate), 24-inch pipeline designed to transport 800 million standard cubic feet of carbon dioxide per day from a location near Donaldsonville, LA, to the Hastings field south of Houston, TX.

The system includes HCA miles, but there are no special permits associated with the system.

The system includes one pump station (Lake Charles) and no storage fields or breakout tanks. The system crosses four (4) navigable rivers (Tensas, Sabine, Atchafalaya, and Mississippi).

Both failures involved line pipe manufactured in 2008 and installed in 2009 and 2010. The pipe was manufactured by Stupp Bros, Inc. and was manufactured to API 5L specification for line pipe. The pipe was fabricated from carbon steel by a High Frequency Longitudinal electric resistance welding method with a mill-applied fusion-bonded epoxy coating. The pipe was 24-inches in diameter, had 0.463-inch wall thickness, and a Specified Minimum Yield Strength of 80,000 pounds per square inch(PSI). According to records by the manufacturer in accordance with API and the operator's standards and specifications, the pipe was subjected to mill ultrasonic testing and short duration hydrostatic burst testing prior to acceptance.

The maximum operating pressure (MOP) of 2,220 psi was established by hydrostatic pressure testing for the respective portions of the line.

Events Leading up to the Failure

The Green Line was in steady-state operation at the time of the discovery of both incidents. The system was operating at 1,344 psig, which is well within the line's normal parameters and the established MOP. No abnormal operating conditions or levels above the MOP were involved in either event. No construction or maintenance activities in the area of the releases occurred at the time of the incidents. The control room and its supervisory control and data acquisition (SCADA) monitoring did not exhibit that it detected the small, pinhole-sized leaks involved.

The first indication of a potential failure started the morning of December 20, 2010. A hunter called to inform Denbury that the ground on the right-of-way (ROW) near Kinder, Louisiana, had indications of a leak. The second incident, February 14, 2011, was noticed by a contract cathodic protection (CP) survey party for Denbury on the ROW near Beaumont, TX.

For each event, Denbury shut-in the respective segments and blew down the line for assessments and repairs.

Due to the pinhole nature of both leaks, neither was detectable by the system's SCADA equipment or the operator's controllers.

Neither of the failures involved any HCAs and occurred in rural, uninhabited locations.

Emergency Response

PHMSA did not initiate a field response to either incident or take part in the line repairs or line restarts. Details as to the emergency response were provided by the operator in subsequent interviews and correspondence and were limited to the following details.

In the first release (December 20, 2010) near Kinder, LA, two pipeline operators were dispatched to the scene.

The Pipeline Regulatory Specialist was notified at this time. The Pipeline Foreman directed the first responding pipeline operator to investigate the site and report. Because there was a foreign pipeline crossing close to the site of the suspected leak, it could not be immediately confirmed that this was a leak from the 24-inch Green Line. The Pipeline Foreman arrived at the scene at noon on December 20, 2010.

EMS USA, Inc. (Denbury's Emergency Response Contractor) was subsequently called out to excavate to determine the source of the leak. They arrived on site on December 20, 2010, at about 1:30 p.m., and the Pipeline Foreman confirmed the leak on December 20, 2010, at 4:30 p.m.

The initial cost to repair the leak was estimated at $40,000, and the leak rate was estimated at 0.5 gal./hr. Personnel on-site estimated that the line would be evacuated within 24 hours, making the confirmed leak size 12 gallons.

At 9:30 p.m., the Pipeline Superintendent produced a revised repair cost estimate of $75,000, making this a National Response Center-reportable (NRC) incident. A NRC report was made at 10:10 p.m. (see Appendix B).

Permits were issued and work commenced to cut the line and remove the leaking section. Details were confirmed for cutting and shipping the damaged pipe specimen to Stork Metallurgical Labs in Houston, TX. Repairs were completed with replacement pipe, and the failed joint was sent for metallurgical testing.

On February 14, 2011, a second leak was discovered near Beaumont, TX. A contract CP survey crew reported the suspected leak to Denbury operations and regulatory personnel at approximately 1:00 p.m. Upon further investigation by operator personnel, the location of the potential leak was at a crossing with two other pipelines. Denbury elected to have their emergency response contractor excavate to confirm that the leak was from their pipeline and not from another source. The contractors confirmed the leak was from Denbury's pipeline at 5:30 p.m.

The initial cost to repair the leak was estimated at $90,000, which would require NRC telephonic reporting. The NRC report was electronically submitted at 7:12 p.m. (see Appendix B). The leak rate was estimated at 2 gallons per hour. The line segment was isolated on February 16, 2011, at 4:00 p.m.

As with the first failure, the leaking 24–inch-diameter, 46-foot-long joint was removed and sent to Stork Metallurgical Testing. A replacement joint was welded in, and the repair method and weld x-rays were accepted. The weld repair areas were doped and wrapped per the operator's repair procedures.

Due to the physical characteristics of the product being transported (CO_2), no product recovery was performed as the product dissipated to the atmosphere upon release.

In the case of both incidents, the lines were re-commissioned and put back into service shortly following the completion of both repairs. In neither instance were there any additional complications with the operators or the community responders. No other agencies, either Federal or State, were involved due to the remote rural nature of both release sites.

Summary of Initial Start-up Plan and Return-to-Service, Including Preliminary Safety Measures

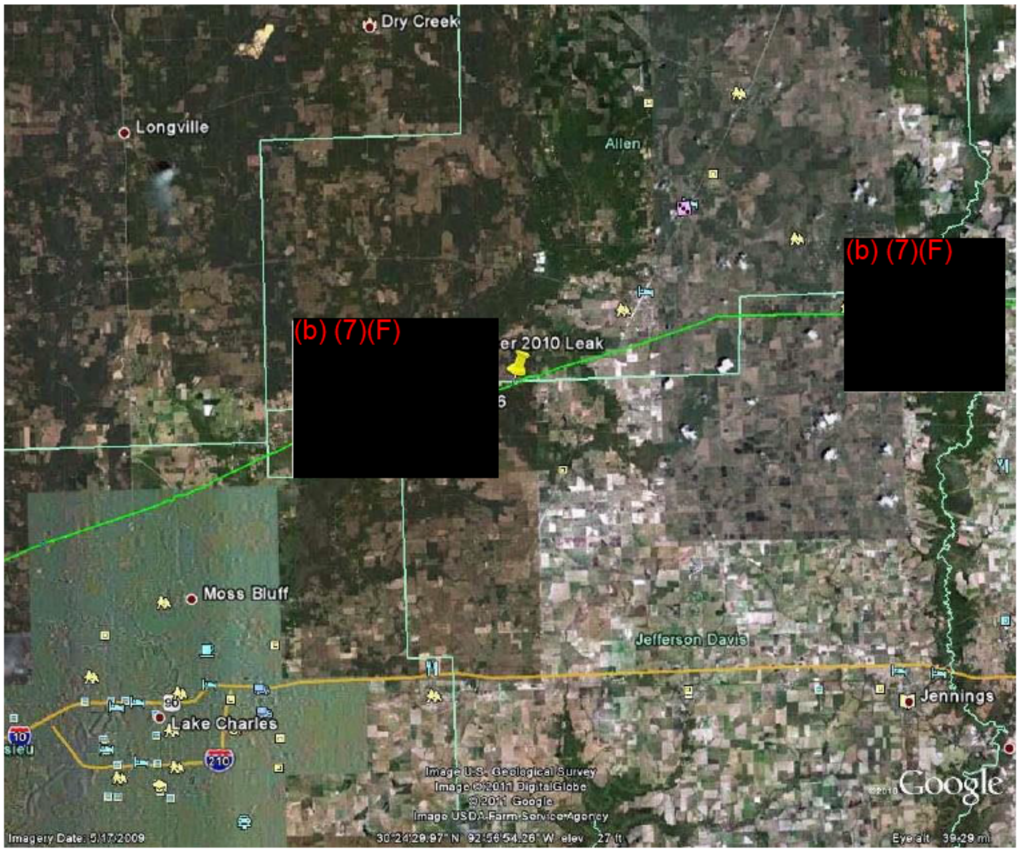
PHMSA was not involved directly with the return-to-service of the line following each incident. According to the operator's DOT coordinator, the line was re-started after each incident/repair in accordance with the operator's operating procedures. The lines remained exposed briefly after each repair was made so visual and physical observations of the repaired joints could be made during the re-start to assure no further leaks were occurring from the repairs. The repaired lines were then subsequently reburied without further complication.

Investigation Findings & Contributing Factors

Investigation Details

The first leak site was located in a rural agricultural field (non-HCA) about 6.8 miles from the nearest town of Kinder, LA.

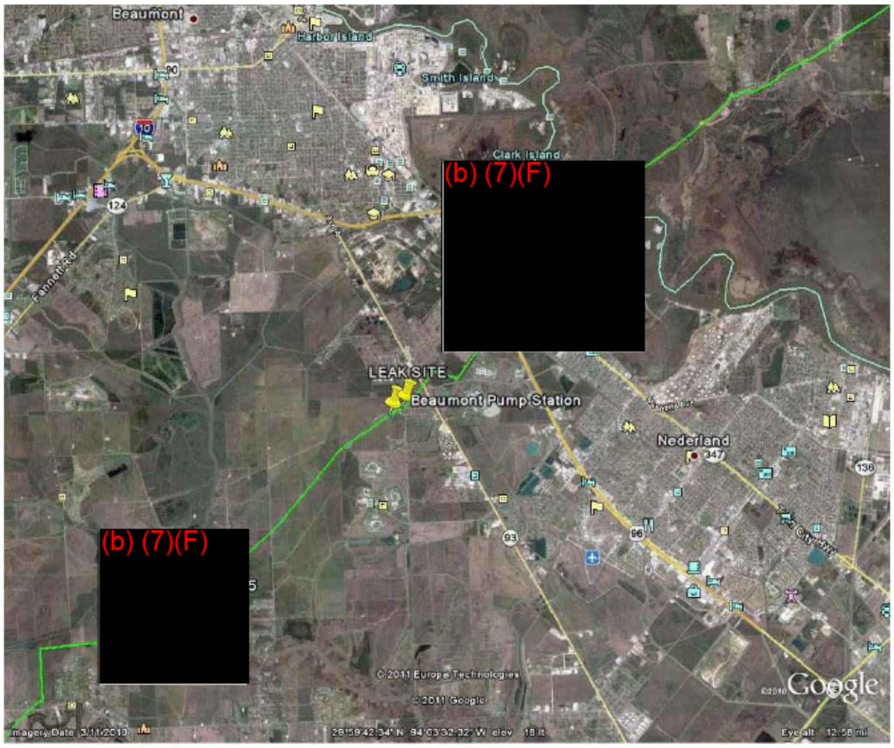
2010 Release in approximate center of photo



Area Map of 2010 Leak

The second leak site was also located in a rural unimproved area (non-HCA) on the outskirts of Beaumont, Texas.

2011 Release in approximate center of photo



Area Map for 2011 Leak

Both releases occurred in non-HCA areas. The size of the leaks and the physical characteristics of the product did not create any concerns about migration of the released product to any nearby HCAs.

Individuals, through visual observations, discovered both leaks and reported them to the operator's control center. The leaks were below the detection limits of the operator's SCADA system and its software (5 percent of total flow is the current lower detectable limit, and the leaks did not meet this threshold). In both instances, the operator shut-in the line sections of the suspected leak sites and dispatched emergency response contractors to the suspected releases sites upon receiving notice. Requisite telephonic reports to the NRC, as well as DOT Accident Reports (DOT 7000-1), for each incident were made upon confirmation of a release in a timely manner (see Appendix C).

As a relatively new line at the time of the failures (constructed in 2009), the operation and maintenance history/records provided little detail as to any causal factors for the failures. No previous accidents or failures were associated with the line. The line was in normal operation at the time of both failure discoveries.

A PHMSA investigator was initially assigned to the first incident on January 10, 2011, prior to the delivery of the first failed specimen to the metallurgical laboratory, Stork Testing and Metallurgical Consulting, Inc. (Stork) in Houston, TX. The specimen was a section of cutout pipe that contained the leak that was part of the newly constructed line. The specimen was 24–inches in outside diameter, had 0.463-inch wall thickness., was built to API 5L/ISO 3183:2007 Grade X80 specifications, and was manufactured by Stupp Corporation (Baton Rouge, LA) with thin film fusion-bonded epoxy coating by Bayou Coating (Baton Rouge, LA).

Metallurgical examinations of both failed specimens concluded that both failures had originated in the long seams of both joints due to welding imperfections, commonly referred to as "penetrators," in the manufacturing process (see Appendix D).

The defects in these joints had not been identified during the mill inspections at Stupp, prompting further communication and review of mill records by the mill, the operator, and PHMSA to identify any similar joints that may have been installed into the line. After discussions with industry sources, Denbury believed these types of penetrator flaws were beyond the detection limits of current ILI tools and the technology available. This prompted an in-depth review of mill records by Stupp and Denbury, at the suggestion of PHMSA, after Denbury provided the metallurgical analysis of the failed specimens.

Stupp's review revealed that one of the joints should have been rejected at the mill based on the ultrasonic testing (UT) inspection data. For the second joint, the mill UT inspection data did not have any readings near the flaw detection threshold. This prompted Stupp to review the UT records for the entire Denbury order. A total of 31 joints of pipe were identified as close to the detection threshold by a Stupp American Society for Non-destructive Testing (ASNT)-certified Level III inspector assisted by ASNT Level II operators during the review. This identification process involved looking at 21,036 pieces of pipe and generating 2 or more UT inspection charts. Some pieces were subjected to multiple ultrasonic inspections because any pipe that required reworking was re-inspected after the rework operation. In total, 48,212 charts were reviewed.

Those 31 joints were identified as the most likely to contain a penetrator flaw. Denbury furthermore proposed to sample 10 percent of those joints (3 joints),perform investigative digs, expose the joints, and perform magnetic particle inspection and UT examinations on their longitudinal seams. PHMSA concurred with this decision. The three joints/sites were chosen for their similarities to the location of the previous failures. Prior to the digs, external corrosion direct assessment examination was performed at each site, which consisted of close interval surveys (CIS) and alternating current voltage gradient (ACVG) surveys, to investigate these areas by direct assessment and compare survey results against any external corrosion anomalies that were found. Confirmation digs were performed with the PHMSA investigator present.

Confirmation Dig of Identified Pipe Joint

Field Ultrasonic Testing of Identified Pipe Joint's Long Seam for Potential Weld Imperfections "Penetrators"

The results for all three confirmatory digs resulted in the following similar results:

- A magnetic particle inspection of the long seams found surface indications that were removed by light grinding. A re-examination by magnetic particle returned satisfactory results.
- An ultrasonic examination resulted in "No indications noted."

Conclusions

Joints dug up through confirmatory digs exhibited no detectable flaws in their long seams when ultrasonically examined. From these results, it was concluded that additional digs would likely provide no additional benefits.

Additionally, Denbury committed to foot patrolling their Green Line (excluding the portion in Galveston Bay, which was constructed from pipe from mills other than Stupp) annually for 3 years. Patrols were completed in 2011, 2012, and 2013, with no evidence of additional leaks occurring. A physical examination of the failure specimens, visual examinations of the exposed pipe during confirmation digs, as well as reviews of the CP records and the CIS and ACVG surveys excluded external corrosion as a causal or related factor in the failure investigation of both incidents.

No evidence of construction, operational, maintenance, or control room factors were relatable as causal factors to either incident. Reviews of records showed no incidences of inadequate/inappropriate hydrostatic testing of the line prior to service, no MOP exceedances in the operation of the line, or any identified cyclical issues .

Based upon these investigative findings, it was concluded that the cause of both failures were a result of long seam manufacturing defects in the welds from penetrator flaws that created pinhole leaks. Reviews of the mill UT records for the entire pipe run for Denbury, results from confirmatory dig UT testing, as well as three successive annual leak foot patrols suggests that other pipe in this line does not contain similar flaws.

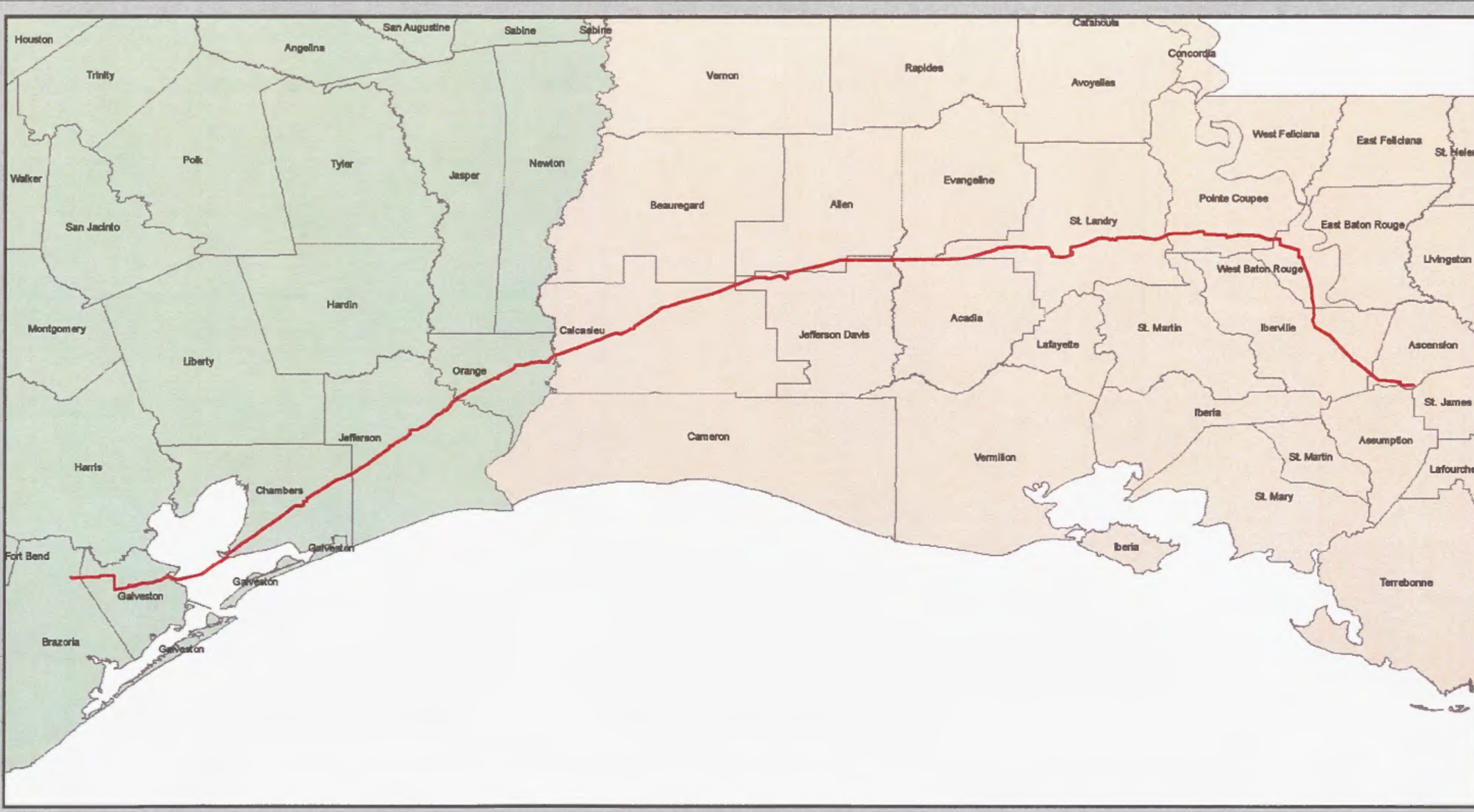
Appendices

A Map and Photographs

B NRC Reports

C Operator Accident Report PHMSA F7000.1

D Metallurgical Laboratory Analysis



Legend

Green Pipeline
Louisiana
Texas

1 in = 20 miles

Green Pipeline

Denbury Gulf Coast Pipeline, LLC
Denbury Green Pipeline-Texas, LLC

Denbury

Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

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[Return to Search]

NRC Number:	962959		
Call Date:	12/22/2010	Call Time:	23:01:31

Caller Information

First Name:	MARK	Last Name:	BRANDON
Company Name:	DENBURY ONSHORE, LLC		
Address:	5100 TENNYSON PKWY		
City:	PLANO	State:	TX
Country:	USA	Zip:	75024
Phone 1:	6019197612	Phone 2:	
Organization Type:	PRIVA	Is caller the spiller?	(●) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (●) No ( ) No Response		

Discharger Information

First Name:	MARK	Last Name:	BRANDON
Company Name:	DENBURY ONSHORE, LLC		
Address:	5100 TENNYSON PKWY		
City:	PLANO	State:	TX
Country:	USA	Zip:	75024
Phone 1:	6019197612	Phone 2:	
Organization Type:	PRIVA		

Spill Information

State:	LA	County:	JEFFERSON DAVIS
Nearest City:	KINDER	Zip Code:	

Location

Spill Date:	12/20/2010 (mm/dd/yyyy)	Spill Time:	16:30:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

CALLER IS REPORTING THAT CARBON DIOXIDE RELEASED FROM A PIPELINE DUE TO FAILURE IN THE PIPE.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
CARBON DIOXIDE	CDO	12 GALLON(S)	

Medium Type: <- Select Medium Type

Additional Medium Information:

/ATMOSPHERE

Injuries: Fatalites:

Evacuations:	Yes ● No Unknown	No. of Evacuations:	
Damages:	● Yes No Unknown	Damage Amount:	75000
Federal Agency Notified:	Yes No ● Unknown	State Agency Notified:	Yes No ● Unknown
Other Agency Notified:	Yes No ● Unknown		

Remedial Actions

VALVES HAVE BEEN CLOSED, ANTICIPATE REPAIRING THE LINE 12/23

Additional Info

CALLER HAD NO ADDITIONAL INFORMATION.

Latitude

Degrees: 30	Minutes: 26	Seconds: 3	Quadrant: N

Longitude

Degrees: 92	Minutes: 57	Seconds: 1	Quadrant: W
Distance from City:		Direction:	
Section:		Township:	
Range:		Milepost:	

Rescinded Comments (max 250 characters)

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

HMIS->INCIDENTS->TELEPHONICS

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[Return to Search]

NRC Number: 967463
Call Date: 02/14/2011 **Call Time:** 20:12:21

Caller Information

First Name:	MARK	Last Name:	BRANDON
Company Name:	DENBURY GREEN PIPELINE-TEXAS, LLC		
Address:	5320 LEGACY DR		
City:	PLANO	State:	TX
Country:	USA	Zip:	75024
Phone 1:	8019197812	Phone 2:	8017166227
Organization Type:	PRIVA	Is caller the spiller?	Yes (●) No No Response
Confidential:	Yes (●) No No Response		

Discharger Information

First Name:	MARK	Last Name:	BRANDON
Company Name:	DENBURY GREEN PIPELINE-TEXAS		
Address:	5320 LEGACY DR		
City:	PLANO	State:	TX
Country:	USA	Zip:	75024
Phone 1:	8019197812	Phone 2:	
Organization Type:	PRIVA		

Spill Information

State:	TX	County:	JEFFERSON
Nearest City:	PORT ARTHUR, TX	Zip Code:	

Location

UNKNOWN

Spill Date:	02/14/2011 (mm/dd/yyyy)	Spill Time:	17:30:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

A MINOR LEAK DEVELOPED IN THE DENBURY GREEN PIPELINE-TEXAS 24" CARBON DIOXIDE PIPELINE AND WAS DISCOVERED AT THE INTERSECTION OF SEVERAL OTHER PIPELINES. AN EXCAVATION WAS MADE TO CONFIRM THAT THIS WAS A LEAK FROM THE DENBURY PIPELINE

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
CARBON DIOXIDE	CDO	240 CUBIC FEET	

Medium Type: <- Select Medium Type

Additional Medium Information:

CARBON DIOXIDE DISPERSED IN AIR

Injuries: Fatalites:

Evacuations:	Yes (•) No Unknown	No. of Evacuations:	
Damages:	(•) Yes No Unknown	Damage Amount:	90000
Federal Agency Notified:	Yes No (•) Unknown	State Agency Notified:	Yes No (•) Unknown
Other Agency Notified:	Yes No (•) Unknown		

Remedial Actions

FOLLOWING CONFIRMATION OF THE LEAK, PLANS ARE BEING MADE TO BLOCK IN AND BLOW DOWN THE AFFECTED PIPELINE SEGMENT IN ORDER TO MAKE REPAIRS

Additional info

NO ADDITIONAL INFORMATION WAS PROVIDED.

Latitude

Degrees: 29	Minutes: 59	Seconds: 14	Quadrant: N

Longitude

Degrees: 94	Minutes: 4	Seconds: 19	Quadrant: W
Distance from City:	5 MILES	Direction:	NW
Section:		Township:	
Range:		Milepost:	

☐ Rescinded **Comments** (max 250 characters)

<< Previous 3..3 of 3 << Save >>

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2014
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/16/2011
	No.	20110106 - 15780 (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

INSTRUCTIONS

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

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	04/29/2011
1. Operator's OPS-issued Operator Identification Number (OPID):	32543
2. Name of Operator	DENBURY GREEN PIPELINE-TEXAS, LLC
3. Address of Operator:	
3a. Street Address	5320 LEGACY DRIVE
3b. City	PLANO
3c. State	Texas
3d. Zip Code	75024
4. Local time *(24-hr clock)* and date of the Accident:	02/14/2011 17:30
5. Location of Accident:	
Latitude:	29.98722
Longitude:	-94.07171
6. National Response Center Report Number (if applicable):	996746
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/14/2011 19:12
8. Commodity released: *(select only one, based on predominant volume released)*	CO2 (Carbon Dioxide)
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	2.40
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	43,180.00
11. Estimated volume of commodity recovered (Barrels):	
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	

13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	02/16/2011 14:00
14b. Local time pipeline/facility restarted:	02/19/2011 05:18
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	02/14/2011 17:30
18b. Local time Operator resources arrived on site:	02/14/2011 17:30

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Texas
3. Zip Code:	77706
4. City	Beaumont
5. County or Parish	Jefferson
6. Operator-designated location:	Milepost/Valve Station
Specify:	229.5
7. Pipeline/Facility name:	Denbury Green Pipeline-Texas, LLC
8. Segment name/ID:	Beaumont Pigging Station
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	92
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe

- If Pipe, specify:	Pipe Seam
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.463
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	80,000
3d. Pipe specification:	5L
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	STUPP
3g. Year of manufacture:	2008
3h. Pipeline coating type at point of Accident, specify:	Fusion Bonded Epoxy
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	2010
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	Other
- If Other, Describe:	Penetrator
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

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

determination for this Accident site in the Operator's Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated Property Damage:	
8a. Estimated cost of public and non-Operator private property damage	$ 1,000
8b. Estimated cost of commodity lost	$ 93,012
8c. Estimated cost of Operator's property damage & repairs	$ 64,111
8d. Estimated cost of Operator's emergency response	$ 2,520
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 0
Describe:	
8g. Total estimated property damage (sum of above)	$ 160,643

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,344.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	2,220.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5e. below)*	
5a. Type of upstream valve used to initially isolate release source:	Manual
5b. Type of downstream valve used to initially isolate release source:	Manual
5c. Length of segment isolated between valves (ft):	83,495
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? (*select all that apply)*	
- Excessive debris or scale, wax, or other wall buildup	

- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
8. How was the Accident initially identified for the Operator?	Ground Patrol by Operator or its contractor
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Guard Patrol by Operator or its contractor" is selected in Question 8, specify the following:	Contractor working for the Operator
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: (provide an explanation for why the Operator did not investigate)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	The size of the leak could not have been expected to be detected by the controller or the currently installed CPM leak detection system software. (5% of total flow is the current lower detectable limit)
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- 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 Accident, 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. Specify how many were tested:	

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

PART G – APPARENT CAUSE

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

Apparent Cause:	G5 - Material Failure of Pipe or Weld

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

External Corrosion:	
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 Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type 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	

- Other:	
- If Other, Describe:	
10. Was the commodity 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 Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	

1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	

G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column

Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	

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

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

9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	Original Manufacturing-related (NOT girth weld or other welds formed in the field)
1. The sub-cause selected below is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	Yes
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	Yes
- If Other, Describe:	Penetrator
- If Environmental Cracking-related:	
3. Specify:	
- Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	Yes
- If Other, Describe:	Penetrator
5. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
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	Yes
Most recent year run:	2010
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	

Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	Yes
- If Yes:	
Most recent year tested:	2010
Test pressure (psig):	2,810.00
7. Has one or more Direct Assessment been conducted on the pipeline segment?	Yes, but the point of the Accident was not identified as a dig site
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	2010
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	No
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Pump), Tank Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	

- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	

G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column

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

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

On February 14, 2011 a contract survey crew noticed indications of a potential leak on a Denbury right-of-way near Beaumont, Texas. They reported the leak to Denbury operations and regulatory personnel at approximately 1:00PM. Upon further investigation, the location of the potential leak was at a crossing with two other pipelines. Denbury elected to have a contractor excavate to confirm that the leak was from our pipeline or from another source. It was confirmed that the leak was from Denbury¿s pipeline at 5:30PM.

The initial cost to repair the leak was estimated at $90,000, which would require National Response Center telephonic reporting. The NRC report was electronically submitted at 7:12PM. The leak rate was estimated at 2 gallons per hour. Isolation of the line segment was accomplished on February 16, 2011 at 4:00PM. The line was blown down from MLV-22 to the Beaumont Station (15.8 miles). On February 17, 2011, Troy Construction began line repair work. Other project details and logistics were confirmed, including moving pre-tested pipe from the Winnie, Texas yard to the jobsite and making coating repairs to the pre-tested pipe. OQ and Drug and Alcohol Plans were confirmed with all participating contractors and their personnel.

With blowdown of the line complete and a pre-job safety meeting conducted, air movers were installed at MLV-24 and Beaumont Station in preparation to replace leaking pipe 300 yards east of Beaumont Station. Removed the leaking 24¿ 46¿ long joint and made 1 weld on replacing pipe. X-ray was accepted.

Made second tie in weld on new section of pipe. X-ray was accepted. Doped and wrapped welds and backfilled. Started re-commissioning Green Pipeline from MLV-22 to Beaumont Station on February 18, 2011 at 1:20PM. Pipeline was back in service on February 19, 2011 at 5:18AM.

[redacted]ame

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	04/28/2011

Appendix D

Examination of Leak in 24-inch OD Denbury Green Pipeline

This document is on file at PHMSA