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

Principal Investigator	Roger Sneegas
Region Director	David Barrett
Date of Report	1/11/2012
Subject	Failure Investigation Report – Southern Star Butt Weld Failure in KS

Operator, Location, & Consequences

Date of Failure	3/2/2010
Commodity Released	Natural Gas
City/County & State	Abbyville/Reno, Kansas
OpID & Operator Name	31711 Southern Star Central Gas Pipeline Co. Inc.
Unit # & Unit Name	853 Lyons
SMART Activity #	129328
Milepost / Location	Station 140 – 260+06, milepost 161, About 10 miles downstream of Stafford Station.
Type of Failure	Butt weld separated due to crack in weld and external forces
Fatalities	0
Injuries	0
Description of area impacted	Class 1 rural pasture land – wetland near a river
Property Damage	$953,905

Executive Summary

At approximately 4:20 am on March 2, 2010, a pipeline rupture resulted in an unintentional release of natural gas from a Southern Star gas pipeline located in Reno County, KS. An estimated 91,089 thousand cubic feet (Mcf) of natural gas was released from the pipeline. The incident occurred on the pipeline right-of-way near milepost 161 in a wetland in a Class 1 Location. No fatalities or injuries occurred as a result of the incident and the gas did not ignite. The total cost of the incident is estimated at $953,905. Gas service was temporarily interrupted to the town of Partridge, Kansas until Southern Star could provide a temporary connection from another line. The 26-inch butt weld failure was caused by tensile overload in the presence of a large crack in the girth weld.

System Details

Southern Star's RA line is a 26-inch diameter natural gas loop pipeline that parallels the R Line for about 26 miles southwest of Hesston, Kansas. The R Line moves natural gas from the Hugoton, Kansas gas production fields to Hesston, Kansas and eventually to the Kansas City area.

At the incident location, the pipeline is constructed of material having the characteristics of API 5L line pipe. The specified minimum yield strength (SMYS), 60,000 psig, has been established by supplier receipts. The pipeline was installed in 1968 and consists of new pipe manufactured by National Tube. The pipe is 0.281-inch wall thickness, coated with coal tar enamel and glass felt and the longitudinal seam is double submerged arc welded (DSAW).

The pipeline maximum allowable operating pressure (MAOP) was established by hydrostatic test in conformance with 49CFR 192.619(a) (1) and (2) in 1968. The test pressure was 1,260 psig and Southern Star established an MAOP of 900 psig after considering the weakest component of the pipeline. A review of Southern Star leak records identified no pipeline leaks on the RA Line in the last 5 years.

Events Leading up to the Failure

On the day of the failure, Southern Star was operating the pipeline at 833 psig, which corresponds to a hoop stress of 64.2% of SMYS.

Emergency Response

On March 2, 2010 at 4:20 am, Southern Star gas control received a low pressure indication (100 psig drop) on the R and RA line system. At 4:30 am the controller contacted field operations and asked them to check for any problems in the vicinity of Hesston Station. Although the failure was closer to the Stafford Station, Southern Star has a field office at the Station in Hesston, so personnel were available to respond. At 5:08 am a third party reported a pipeline leak to Reno County Kansas Emergency Services. Southern Star employees were dispatched to the Incident site starting at 5:08 am. Reno County fire, police and emergency services were already on site and starting evacuations. The Southern Star field office immediately dispatched the District Manager who arrived on site at 6:06 am and confirmed the leak.

The affected section of pipeline was isolated by manually closing the upstream mainline valve (Langdon MLV) and the downstream mainline valve (RA Arkansas River MLV). Both valves were operated at about 7:45 am. The 24 mile long pipeline segment was blown down to 0 psig by about 8:30 am.

Sothern Star notified the National Response Center (NRC) at 9:02 am (Appendix B).

Summary of Return-to-Service

After the field investigation at the failure site was complete, replacement pipe was installed in the area where the Incident occurred. Gas service to the town of Partridge was provided through a crossover valve from the R Line. This temporary system did not include a pressure regulating device, so Southern Star personnel manually operated the crossover valve to regulate the pressure to Partridge. Southern Star also hydrotested an isolated one-mile segment of the pipeline that included the failure location.

Southern Star presented a return to service plan for the RA line on April 20, 2010. As a part of the plan, they engaged Kiefner and Associates to analyze 2008 magnetic flux leakage (MFL) in-line inspection (ILI) results for the RA line. The analysis was intended to find correlations between crack features in the ILI results and actual cracks in girth welds. After reviewing the ILI results, Southern Star excavated girth welds to physically inspect for cracks. After several iterations Southern Star and Kiefner developed a process that accurately identified girth weld cracks about 50% of the time. The metallurgical analysis of the failed weld determined that external forces were required, in addition to a crack, to cause failure of the weld. The locations of ILI crack indications were prioritized based on the presence external stresses such as buoyant forces or soil subsidence. The indications in the higher priority areas were then excavated and repaired. A geotechnical consultant was also engaged to identify the high risk areas.

Based on the analysis and repairs on the RA line, PHMSA Central Region approved the return to service plan and the RA line was re-started on December 12, 2011. After re-start Southern Star also agreed to do an instrumented leak survey and another ILI run with geospatial capability. The ILI run will then be compared with a previous run to determine areas where the pipeline has moved enough to cause additional stress on the welds.

Investigation Details

On March 3, 2010, PHMSA Central Region inspectors conducted an on-site investigation of the incident. In situ visual inspection of the damaged pipe joint revealed a circumferential separation of a girth weld. The pipe ends were horizontally separated by about 2 inches and vertically offset about 6 inches. The pipeline longitudinal seams were located between 12:00 and 3:00. See pictures in Appendix A.

At the failure location, the pipeline lies in a wetland near the Ninnescaw River. Preceding the incident, the weather had begun to warm and the snow at the site was starting to melt. However, subsequent excavations showed that the ground was still frozen over the pipeline. At the time of the incident the wetland was dry at the surface. However the water table in the area was high enough that Southern Star needed to continually pump water out of the excavation. Pipeline anchors were noted in the area of the failure during the field investigation. Southern Star reported that screw anchors were at 30 foot centers in the area of the failure; indicating that buoyant forces were considered during the pipeline construction. The soil in the area was sandy so stress from clay soil expansion was not a factor in the failure. The Ninnescaw River is about 300 feet northeast of the failure site so soil subsidence on the river bank is another possible contributing factor.

Southern Star removed a section of pipe containing the failed weld (#17330) near milepost 161. This section of pipe was transported to Kiefner and Associates for metallurgical analysis (Appendix D). The analysis concluded the failure originated in a hydrogen-assisted crack in the girth weld. The crack was circumferentially oriented, 16.5 inches long, and centered at approximately the 9:00 position, and had a maximum depth of about 71% of the pipe wall.

Southern Star also excavated and x-rayed 10 welds adjacent to the failure; 4 upstream and 6 downstream. Circumferential cracks were found in 8 of the 10 additional welds x-rayed. These cracks were almost evenly distributed at every clock position except 9:00. In addition to the 10 welds in the vicinity of the failure, Southern Star has excavated and x-rayed 22 other welds in the area. Of the 32 welds x-rayed, all were either cut out and replaced or repaired with a weld wrap.

A high-resolution MFL tool was run on the pipeline in 2008. The tool indicated an 11% metal loss anomaly at the failed girth weld. The circumferential feature length was 1.5 inches. This indication did not meet Southern Star's repair criteria at the time.

Southern Star updated its incident report to PHMSA after the completion of the metallurgical analysis (Appendix C).

Investigation Findings & Contributing Factors

The Southern Star 26-inch diameter RA Line Incident was caused by tensile overload in the presence of a large crack in a girth weld. The crack initiated during construction in 1968. The metallurgical analysis calculated that the longitudinal stress on the pipeline from temperature variations and line pressure was not enough to cause the weld failure. The calculated failure stress on the weld indicated an additional 10 ksi was required to cause the failure. The most likely source is additional bending stress from pipe buoyancy in a rising water table. The screw anchors used in the area of the failure were apparently not effective in the wetland soil surrounding the pipeline.

Appendices

A Map and Photographs

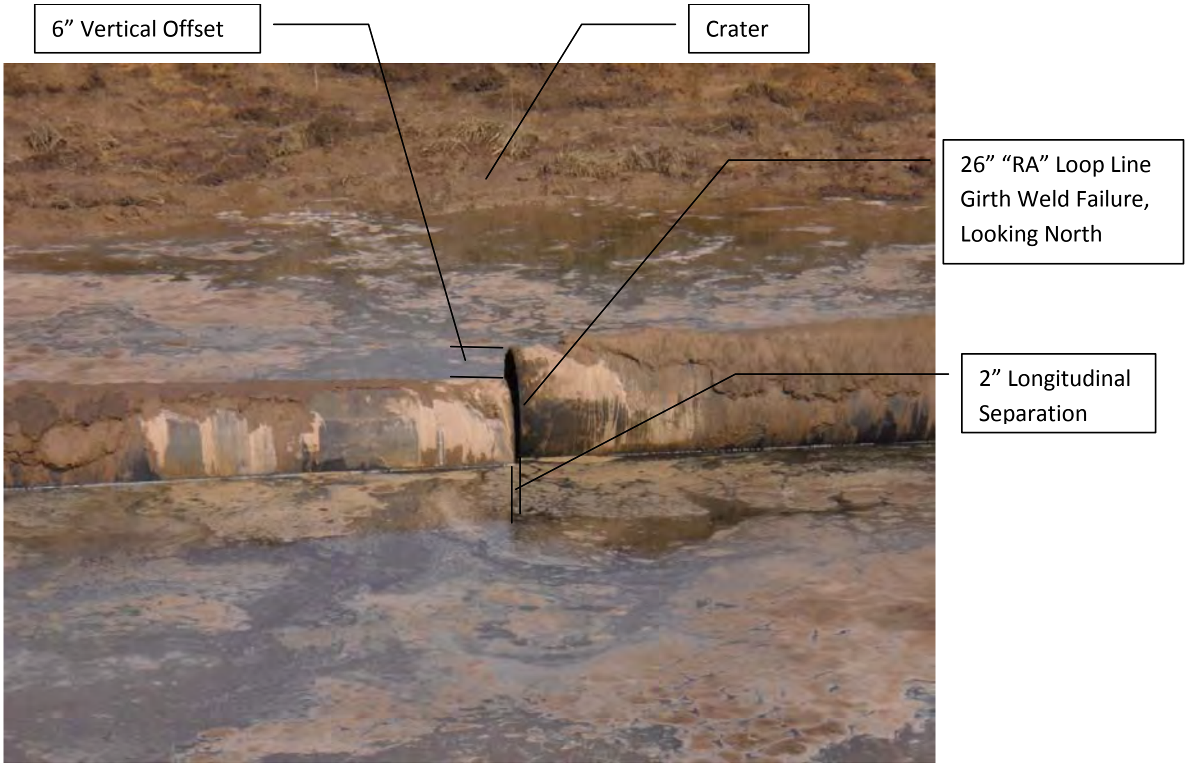
B NRC Report No. 932729

C Incident Report 20100006

D Kiefner Laboratory Analysis

APPENDIX A Maps and Photographs

Photo number 1 of failure and site map March 4, 2010



Rescinded **Comments** (max 250 characters)

NRC Number: **932729**
Call Date: **03/02/2010** **Call Time:** **09:02:29**

Caller Information

First Name:	MATT	Last Name:	MCCOY
Company Name:	SOUTHERN STAR CENTRAL GAS PIPELINE		
Address:	4700 HWY 56		
City:	OWENSBORO	State:	KY
Country:	USA	Zip:	42304
Phone 1:	2708524450	Phone 2:	
Organization Type:	PRIVATE EN	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	MATT	Last Name:	MCCOY
Company Name:	SOUTHERN STAR CENTRAL GAS PIPELINE		
Address:	4700 HWY 56		
City:	OWENSBORO	State:	KY
Country:	USA	Zip:	42304
Phone 1:	2708524450	Phone 2:	
Organization Type:	PRIVATE EN		

Spill Information

State:	KS	County:	RENO
Nearest City:		Zip Code:	

Location

1/2 MILE EAST OF ANDRE RD AND RED ROCK R

Spill Date:	03/02/2010 (mm/dd/yyyy)	Spill Time:	04:20:00 (24hh:mm:ss)
DTG Type:	DISCOVERED		
Incident Type	PIPELINE	Reported Incident Type	PIPELINE

Description

CALLER REPORTED A PIPELINE RUPTURE DUE TO UNKNOWN REASONS.

Appendix B NRC Report

Materials Involved

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

Medium Type: AIR

Additional Medium Information:

ATMOSPHERE

Injuries:

Fatalites:

Evacuations: ○ Yes ◉ No ○ Unknown

No. of Evacuations:

Damages: ○ Yes ◉ No ○ Unknown

Damage Amount:

Federal Agency Notified: ○ Yes ○ No ◉ Unknown

State Agency Notified: ○ Yes ○ No ◉ Unknown

Other Agency Notified: ○ Yes ○ No ◉ Unknown

Remedial Actions

CLEAN UP CREW ON-SITE,INVESTIGATION UNDERWAY

Additional Info

CALLER HAD NO ADDITIONAL INFORMATION.

Latitude

Degrees: Minutes: Seconds: Quadrant:

Longitude

Degrees: Minutes: Seconds: Quadrant:

Distance from City:

Direction:

Section: 25

Township: 24S

Range: 9E

Milepost:

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:**	03/26/2010
	No.	20100006 - 15418 (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

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

Last Revision Date:	01/10/2012
1. Operator's OPS-issued Operator Identification Number (OPID):	31711
2. Name of Operator	SOUTHERN STAR CENTRAL GAS PIPELINE, INC
3. Address of Operator:	
3a. Street Address	4700 HIGHWAY 56; BOX 20010
3b. City	OWENSBORO
3c. State	Kentucky
3d. Zip Code:	42301
4. Local time *(24-hr clock)* and date of the Incident:	03/02/2010 04:20
5. Location of Incident:	
Latitude:	37.94216
Longitude:	-98.25881
6. National Response Center Report Number (if applicable):	932729
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	03/02/2010 08:00
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):	91,089.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	Yes
- If No, Explain:	

- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	03/02/2010 08:00
15b. Local time pipeline/facility restarted	
- Still shut down? (* Supplemental Report Required)	Yes
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	20
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	03/02/2010 04:20
19b. Local time operator resources arrived on site	03/02/2010 06:03

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:	Kansas
3. Zip Code:	67510
4. City	Abbyville
5. County or Parish	Reno
6. Operator designated location	Survey Station No.
Specify:	140/26053
7. Pipeline/Facility name:	Hugoton 26" Loop
8. Segment name/ID:	RA
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):	40
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:	Weld, including heat-affected zone
- If Pipe – Specify:	
3a. Nominal diameter of pipe (in):	
3b. Wall thickness (in):	
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	
3d. Pipe specification:	
3e. Pipe Seam – Specify:	

- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Incident – Specify:	
- If Other, Describe:	
- If Weld, including heat-affected zone – Specify:	Pipe Girth Weld
- 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:	1968
5. Material involved in Incident:	Carbon Steel
- If Material other than Steel or Plastic – Specify:	
6. Type of Incident involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other – Describe:	
- If Rupture - Select Orientation:	Circumferential
- If Other – Describe:	
Approx. size: in. (widest opening):	
by in. (length circumferentially or axially):	81.6
- 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:	538
4. Were any structures outside the PIR impacted or otherwise damaged due to heat/fire resulting from the Incident?	No
5. Were any structures outside the PIR impacted or otherwise damaged NOT by heat/fire resulting from the Incident?	No
6. Were any of the fatalities or injuries reported for persons located outside the PIR?	No
7. Estimated cost to Operator :	
7a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$ 0
7b. Estimated cost of gas released unintentionally	$ 313,880
7c. Estimated cost of gas released during intentional and controlled blowdown	$ 0
7d. Estimated cost of Operator's property damage & repairs	$ 638,025
7e. Estimated cost of Operator's emergency response	$ 2,000
7f. Estimated other costs	$ 0
Describe:	
7g. Estimated total costs (sum of above)	$ 953,905

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	833.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	900.00
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):	128,139
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No – Which physical features limit tool accommodation? *(select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, which operational factors complicate execution? *(select all that apply)*	
- Excessive debris or scale, wax, or other wall build-up	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other	
- If Other, Describe:	
5f. Function of pipeline system:	Transmission System
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?	Yes
- If Yes:	
6a. Was it operating at the time of the Incident?	Yes
6b. Was it fully functional at the time of the Incident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	Yes
7. How was the Incident initially identified for the Operator?	Controller
- 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)*	The incident was not identified as a controller failure possibility.
- 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:	G5 - Material Failure of Pipe or Weld

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

Corrosion Failure – Sub-cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other	
- If Other – Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other	
- If Other – Describe:	
4. Was the failed item buried under the ground?	
- If Yes:	
4a. Was failed item considered to be under cathodic protection at the time of the incident?	
- If Yes, Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the incident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- If Other, Describe:	
7. Cause of corrosion *(select all that apply)*:	

- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*:	
- Field examination	
- Determined by metallurgical analysis	
- Other	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*:	
- Low point in pipe	
- Elbow	
- Drop-out	
- Other	
- If Other, Describe:	
10. Was the gas/fluid treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage Tool	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	

- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, Describe:	
G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-handed column*	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If 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:	Construction-, Installation-, or Fabrication-related
1. The sub-case selected below is based on the following *(select all that apply)*:	
- Field Examination	Yes
- 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)*	
- If Fatigue or Vibration related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress	Yes
- 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	Yes
- 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?	Yes

5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	Yes
Most recent year run:	2008
- Ultrasonic	
Most recent year run:	
- Geometry	Yes
Most recent year run:	2008
- Caliper	Yes
Most recent year run:	2008
- 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?	No
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline 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:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Incident 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:	
- 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

At 4:20am The Gas Controller noticed a pressure drop at the Stafford Station of approx. 100 psi. in approx. 30 min. At 4:30am The Gas Controller contacted the on call operator to go to Hesston Station to see if he can indentify any problems there. Aslo,the Gas Controllercontacted a second operator on callto go to Stafford Station and see if he can identify any problems there. A pinch was enabled at Stafford Station to hold upstream pressure for power plants. At 5:08am the Gas Controller received a call from Reno County 911 dispatch about a leak at Red Rock Road and Andre Road in Reno County Kansas. The Gas Controller was informed by the dispatcher that Reno County emergency crews were on site. At 6:03am The Southern Star Lyons District Manager arrived on site. At 6:06am Southern Star personnel on site called Gas Control to inform them that he was shutting in the RA line. At 7:22 KGS Ark River is flowing to assist SSCGP. At 8:00am RA was isolated. At 8:40am Southern Star personnel on site called Gas Control to inform him that Ark River is physically shut in to make sure no gas flows into RA line.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Brad Carter
Preparer's Title	Pipeline Safety Data Analyst
Preparer's Telephone Number	270-852-4438
Preparer's E-mail Address	Brad.Carter@SSCGP.com
Preparer's Facsimile Number	270-852-5016
Authorized Signature's Name	David L. Sinclair
Authorized Signature Title	Manager of Pipeline Compliance
Authorized Signature Telephone Number	270-852-4434
Authorized Signature Email	David.L.Sinclair@sscgp.com
Date	01/10/2012

Appendix D Kiefner Laboratory Analysis

This document is on file at PHMSA