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

Principal Investigator	Peter J. Katchmar
Regional Accident Coordinator	Peter J. Katchmar
Region Director	Chris Hoidal
Date of Report	11/07/2012
Subject	Failure Investigation Report – TransCanada/Bison Pipeline Natural Gas Transmission Release near Gillette, WY

Operator, Location, & Consequences

Date of Failure	7/20/2011
Commodity Released	Natural Gas
City/County & State	Gillette/Campbell/Wyoming
OpID & Operator Name	32487 – TransCanada Northern Border Inc. (TransCanada)
Unit # & Unit Name	73819 - Bison Pipeline (MP0 to MP 64.5)
SMART Activity #	135336
Milepost / Location	MP 16.2
Type of Failure	Material Failure of Pipe or Weld/Construction Related
Fatalities	0
Injuries	0
Description of area impacted	Rural, High Desert with rolling hills
Property Damage	$6,700,000 Total

Executive Summary

On July 20th, 2011, Bison Pipeline, operated by TransCanada Northern Border Inc. (TransCanada) experienced a rupture at Milepost 16.2 at approximately 7:30 pm Mountain Daylight Time (MDT). The release site was in a remote, high desert area of rolling hills located in Campbell County, Wyoming approximately 17 miles northwest of Gillette, Wyoming. The release location was about 1 mile uphill and west of the landowner's house. The pressure drop was detected by the line break system and isolation valves were automatically activated. Concurrently, the pressure drop at the Buffalo meter station sixteen miles upstream was identified by TransCanada's supervisory control and data acquisition (SCADA) operations control center (OCC) in Canada. Near the same time, the landowner called TransCanada personnel to report the explosion.

TransCanada personnel were dispatched to the area to assess the situation. The first responders confirmed that a pipeline failure had occurred and that automated isolation valves operated as designed. They secured the site and coordinated with local emergency responders. There was no ignition of the gas or fire and there were no reported injuries or third party property damage. The National Response Center was notified on July 21, 2011 at 13 minutes past midnight EDT (10:13 pm MDT).

The line failed after being in service for approximately six months. The apparent cause of the failure was pipe body rupture that initiated at a defect caused by mechanical damage during construction. The defect was a dent with a crack. The section of line containing the failure feature was hydrostatically tested on November 5, 2010. The maximum hydrostatic test pressure of 1890 psi measured at the test point resulted in a maximum pressure at the failure site of approximately 2004 psi. The pressure differential was due to the elevation difference. The post construction hydrotest caused the pipe dent to re-round and opened a crack in the gouge. A full metallurgical analysis was conducted which determined that the crack was near failure at the end of the hydrostatic test and it was just a matter of time until the internal pressure in the pipe from normal operations drove the defect to failure.

System Details

The Bison Pipeline is a 302 mile long natural gas transmission pipeline. It originates at the Anadarko compressor station northwest of Gillette, Wyoming and travels northeast through Wyoming into southeastern Montana and southwestern North Dakota where it connects with TransCanada's Northern Border Pipeline system (Northern Border) near Northern Border's Compressor Station No. 6 in Morton County, North Dakota. The Bison Pipeline was constructed in 2010 and commenced operation on January 14, 2011. Bison is comprised of 30-inch diameter pipe with a nominal wall thickness of 0.438" (0.72 design factor) between MP 0.00 and MP 64 and a nominal wall thickness of 0.386" (0.80 design factor) between MP 64 and MP 302. The pipeline between MP 64 and MP 302 was commissioned and approved for a maximum operating pressure (MAOP) of 1440 psig under the alternative maximum allowable operating pressure for certain steel pipelines rule pursuant to §192.620.

The line pipe for the Bison Pipeline was manufactured by two companies; Welspun, in Dahej, India, and EVRAZ at their mill in Regina, Canada. The EVRAZ 0.386" wall thickness line pipe was used for the entire pipe downstream of Milepost (MP) 64 to the end of the line at MP 302, as well as a few heavy wall pipe sections installed within the first 64 miles. The failed pipe was rolled by Welspun. This pipe was used only within the first 64.7 miles of the line in Wyoming. Welspun obtained the steel plate from Ilyich Iron and Steel Works of Mariupol in the Ukraine. The pipe was rolled using a double submerged arc welding (DSAW) process for the longitudinal seam according to the 43rd edition of API 5L PSL2 in 2007. The pipe was shipped to the USA in 2008-2009, and upon acceptance, the pipe was double-jointed and coated with fusion bonded epoxy (FBE) external protective coating and an internal friction reduction coating, at Bayou Coating LLC in New Iberia, Louisiana, in 2009.

Events Leading up to the Failure

PHMSA's Western Region (WR) and Central Region worked closely with TransCanada during the construction of the Bison Pipeline in 2010. The WR spent 47 days of field inspections and 17 days of associated in office work during the construction and the CR spent an additional 49 field inspections days and 9 days of associated in office work during the construction. Because the last 238 miles of the Bison line was to be an alternate Maximum Allowable Operating Pressure (AMAOP) pipeline (to be operated at 80% SMYS), TransCanada decided to impose all of the more stringent post construction requirements on the entire pipeline including the first 64 miles of regular MAOP pipeline (to be operated at 72% SMYS). The post construction requirements were to conduct an MFL and geometry in-line-inspection (ILI) survey within six months of commissioning the line as well as conducting a cathodic protection (CP) Close-Interval-Survey (CIS) and a direct current voltage gradient (DCVG) survey within six months of energizing the CP system.

The pipeline was post-construction hydrostatically tested in November 2010 with no leaks or failures. A post construction caliper ILI survey was completed in November 2010 and there were no actionable anomalies identified per 49 CFR Part 192.

The installation of four of the eight impressed current cathodic protection ground beds were delayed due to weather and a 120 day extension to complete the installation of the cathodic protection system was requested and granted by the PHMSA Western Region Director. With the delay of installation of the impressed current cathodic protection systems, the CIS and DCVG surveys were delayed. The DCVG survey was completed on July 22, 2011 and the CIS was completed on September 23, 2011. Results of the CIS and DCVG surveys were provided to PHMSA Western Region after the release.

On the day of the failure, the pipeline pressure was generally consistent at 1340 psig up to the approximate 7:25 pm MDT rupture. TransCanada's Gas Control in Canada observed the drop in pressure and initiated telephone conversations with Anadarko, the gas supplier. The rupture was confirmed and the line was shut in by 8:50 pm MDT. The maximum pressure on the day of the failure was 1396.8 psi as logged by the SCADA system at the upstream Buffalo Meter Station. According to SCADA the failure was estimated to have occurred at a pressure of 1340 psig. Prior to the incident, the pipeline was operating normally.

Emergency Response

TransCanada was made aware of the release by their SCADA system in their Gas Control Center. The on duty controller initiated telephone calls to their gas supplier in an attempt to understand the situation. At nearly the same time, the landowner called TransCanada to report the release. There is an automatic valve just downstream of the release point that closed just after the release. It took some time for the gas supplier to shut down their compressor station at the beginning of the line so TransCanada could close the upstream valve to isolate the release location. TransCanada personnel notified local emergency responders and mobilized personnel to the site. The National Response Center (NRC) was notified at thirteen minutes after midnight on the 21st of July Eastern Daylight Time (EDT). This corresponds to 10:13 pm Mountain Daylight Time (MDT).

PHMSA was made aware of the release by an e-mail report from the National Response Center (NRC) that came in at 10:39 pm MDT on July 20, 2011. By 10:58 pm, PHMSA's Western Region after hour's duty officer had called and talked with TransCanada personnel who confirmed the release but had little further information. PHMSA's WR Accident Coordinator was notified and made contact with the WR Director and by 11:00 pm, it was decided that because the Bison line had just been commissioned, the WR should go to the site and conduct an investigation into the cause of the release. The WR Accident Coordinator left early the next morning and drove to the site, arriving at 10:00 am MDT on July 21, 2011. The site had been secured by TransCanada/Bison representatives the night before and nothing had been touched or removed. PHMSA started the investigation by photographing the location, looking over the fracture surface, generally measuring the pipe to make sure it was all there and conducting informal interviews of first responders and the landowner. The landowner mentioned that his wife had taken some pictures immediately after the release occurred and PHMSA secured a copy of those photographs. The interviews gave little information as to what may have occurred immediately prior to the release that gave any indication as to the apparent cause.

It was determined that there was no nearby construction work that predicated the release so 3rd party damage was removed as a probable cause. Also, the pipe had no apparent internal or external corrosion and the operator reported that there were no apparent pressure excursions prior to the failure. There were some areas of possible external damage located on the pipe which could have occurred during the pipe thrashing about during the release or they could have occurred during construction.

A few hours after PHMSA arrived on site, a metallurgist from TransCanada arrived at the site. The metallurgist and the PHMSA representative conducted a combined review of the failed pipe's fracture surface. The metallurgist indicated that the failure involved a classic 45 degree shear fracture on both ejected pipe fragments and the two arrest ends. He indicated that that fracture mode is indicative of high steel toughness. A number of abrasions on fracture surfaces were interpreted to be secondary abrasions that occurred during the failure event as the pipe came through the ground and landed. He also identified a location where he observed an area of flat fracture that coincided with mechanical damage that he thought might be the origin of failure. He cleaned the fracture surface with water and a tooth brush and photographs were taken of that area as well as the other probable mechanical damage pipe a few feet away. The fracture at the probable origin of failure was observed to have a 'woody' morphology and to have a dark stain line on the surface with a curved profile resembling a possible crack arrest line. The metallurgical laboratory concluded later that the length of the dark stain line was measured to be 4.5" long with a maximum depth of approximately 0.372- inch (89%) of wall thickness. Based on the positions of the long seam welds on the arrest ends and on the elected pipe, the damage was estimated to be located on the top of the pipe at the 10:15 o'clock position (looking downstream). The TransCanada metallurgist explained to the PHMSA investigator that he had seen this type of mechanical damage grow to failure in the past but that it usually took some 30 to 40 years. He found it curious that this mechanical damage grew to failure after the post construction hydrotest in just under 7 months.

PHMSA's investigator released the site to the operator on the afternoon of July 21, 2011. TransCanada personnel had a third party survey crew come in and survey the site, official photographs were taken of the site and the crater size and the location of all pipe thrown from the ditch was documented. Several pieces of the pipe containing the probable failure initiation point and other pipe containing mechanical damage were cut at the site and transported to a third party laboratory for analysis.

Summary of initial start-up plan and return-to-service, including preliminary safety measures

Due to this release occurring within 6 months of commissioning, and the fact that the pipe withstood a post construction hydrotest, PHMSA was concerned with the quality of pipe used to construct the Bison Pipeline. Specifically, PHMSA was concerned that the pipe may have lower than required physical properties which may have allowed the mechanical damage to grow to failure in a very short amount of time. PHMSA issued a Corrective Action Order (CAO) to TransCanada on July, 21, 2011. The CAO required TransCanada to develop a written restart plan prior to repairing and resuming operation of the pipeline; drop the operating pressure to 80% of the failure pressure (not to exceed 1072 psig) at the rupture location; develop a remedial work plan to identify and address any additional anomalous conditions in the pipe; and provide quarterly progress reports to PHMSA's WR.

On July 21st, 2011, TransCanada mobilized an excavation contractor to the site at MP 16.2. The work consisted of repairs to the pipeline and remediation of the terrain. The total length of the pipeline exposed to make repairs to the pipeline was approximately 140'. The failed section was replaced with approximately 109 feet of new pipe that was hydrostatically tested at the site and witnessed by TransCanada Engineering personnel. Pipe used in the repair consisted of 30" diameter, 0.514" wall thickness, Grade X-70. The final tie-in was completed on July 22nd, 2011.

On July 26, 2011, TransCanada submitted a letter to PHMSA requesting to be allowed to return to service at 1200 psig in order to run ILI surveys in order to identify any dents in the pipe similar to the one that failed. PHMSA agreed with the stipulation that TransCanada would immediately reduce the pressure to the CAO requirement of 1072 psig immediately after the ILI surveys were complete.

Because the preliminary cause of the failure was identified as a top-side dent with metal loss PHMSA approved the return to service request contingent upon TransCanada excavating and evaluating all known top side (9 o'clock to 3 o'clock) dents on the pipeline as revealed by either of the 2010 and 2011 ILI runs. Based on information provided by TransCanada after the release, there were at least four (4) topside dents between milepost 0 and milepost 161. PHMSA also required that prior to operating the pipeline that TransCanada provide documentation on the 2010 and 2011 ILI results and any subsequent excavation, assessment, and evaluation of anomalies including dents. Each dent was to be evaluated to confirm that it did not pose a safety risk to operating the line at the modified pressure. PHMSA's WR observed each anomaly dig and confirmed the non-destructive testing of each possible dent.

Investigation Findings & Contributing Factors

Immediately after learning of the release on the Bison line, PHMSA's WR Director requested that his Accident Coordinator drive to the site and initiate an investigation into the cause of the pipe failure. PHMSA's WR staff immediately reviewed all construction documentation in an effort to identify any inspector identified anomalous information with respect to the rupture location. None was identified. Information on the pipe used for constructing the pipeline was also reviewed. It appeared that the pipe met the applicable manufacturing specifications for the 72% MAOP section of line from MP 0 to MP 64 and in fact met the TransCanada specification for the 80% pipe from MP 65 to MP 302 (TES-PIPE-SAW-US). PHMSA requested, received and reviewed all post construction integrity surveys. These included the post construction hydrotest, the post hydrotest caliper ILI survey, the DCVG Survey and the July partial combination ILI survey.

The post construction caliper tool was a rudimentary tool which identified a reported 1.1% outside diameter (OD) dent at the release location. A combination MFL and geometry ILI survey was conducted in July 2011; 2 weeks prior to the failure. The results were not available before the release. After full review of the ILI survey, it was determined that the tool collected data for only a portion of the line surveyed and so a rerun had been scheduled. The tool did collect data for the first section of pipeline that contained the release. That ILI survey identified a 0.5% OD dent at the release location. A DCVG survey was conducted on the Bison line in June 2011. This survey identified a coating holiday DCVG indication of 14.57% voltage drop (IR) coincident with the slight dent at the rupture location.

None of these anomalies were actionable per the criteria listed in PHMSA's regulations or in industry standards at the time they were detected. It was not until after the July 20th release that the different survey results were overlaid and only then did it become obvious that a criterion for action, a dent with metal loss requiring immediate mitigation, was identified.

TransCanada contracted with a third party metallurgical laboratory to perform a full metallurgical analysis on the failed pipe in an effort to determine the probable cause of the release and to make a determination of why the pipe failed within 6 months of commissioning. The first metallurgical report contained a detailed description of the pipe properties and the anomaly at the rupture location. The anomaly was confirmed as the origin of the failure but the report was inconclusive as to the reason for the rapid growth of the anomaly to failure within 6 months after the post construction hydrotest.

Because the first metallurgical laboratory could not specifically determine the mechanism that caused the anomaly to grow to failure in the apparent rapid manner that it did, PHMSA was reluctant to accept the results as final and close the investigation. Discussions with TransCanada led to further metallurgical testing by a laboratory that had the ability to clarify if hydrogen cracking was the cause of the rapid crack growth of the anomaly involved in the release. Three critical tests were performed to clarify if hydrogen cracking was involved in the rapid crack growth: (1) slow strain rate tensile (SSRT) testing in NS4 solution under hydrogen charging condition; (2) SSRT in air, and (3) SEM characterization of the nature of blisters and cleavage.

<u>The following is the executive summary from the first laboratory report:</u>
"The failure originated in a 6.4-inch (12.7 cm) long area of mechanical damage. The total extent of mechanical damage at the failure origin was approximately 13 inches (33 cm). The pipeline failed as a rupture that propagated longitudinally approximately 81 feet (25m) prior to termination. Two pipe sections were ejected from the ditch line during the failure, one approximately 68 feet long (21 m) and one approximately 13 feet long (4 m). The mechanical damage removed up to 11-percent of the pipe wall thickness. Rerounding cracks to a maximum depth of 14-percent of the pipe wall thickness developed in the mechanical damage that propagated to failure in less than 7 months of operation. The combination of the mechanically damaged material removed from the pipe outside surface and the re-rounding cracks reduced the effective pipe wall thickness by 25-percent with an initial length of 3.2 inches (8 cm). Mechanically damaged areas on high strength line-pipe can be susceptible to crack propagation due to a number of possible individual degradation mechanisms or a combination of degradation mechanisms. The microstructure of the pipe where the failure occurred consists of bands of fine grained ferrite and pearlite. The morphology of the propagated crack portion of the fracture surface was layers of cleavage bounded by layers of shear. The maximum depth of the cracking was 89-percent of the nominal pipe wall thickness. The final portion of the fracture was ductile shear adjacent to the inside pipe surface. Further testing is being performed to determine the degradation mechanisms responsible for the rapid crack growth from the initial mechanical damage.

The pipe specimen met the requirements of API Specification 5L, 43nd Edition, March 2004, for Grade X70 Welded Line Pipe, the API specification in effect the year the pipe was manufactured."

<u>The following is the executive summary from the second laboratory report:</u>
"Kiefner Associates, Inc. (KAI) reported in the analysis of the Bison Pipeline incident a rapid crack propagation of 500 mils per year for the six month in-service operation after commissioning. Since the presumed rapid crack growth rate could not be explained with any of the common steel degradation mechanisms, such as external corrosion, SCC, cold creep, fatigue and corrosion fatigue, KAI in its first draft report attributed it to hydrogen assisted cracking in very aggressive environments. The observational evidence for this mechanism was the partial material cleavage on the fracture surface and microvoids assumed to be hydrogen blisters in the vicinity of fracture surfaces. However, from the six months operating history, the environment at the rupture location could not be classified as aggressive. Therefore, the presumed "hydrogen assisted cracking" mechanism was removed from KAI's third draft, i.e., the final report but the rapid crack growth issue remained unresolved.

TransCanada requested Blade Energy Partners to perform a supplemental investigation with an objective to provide factual evidence for the rapid crack propagation mechanism. The scope of work consisted of six investigation components, including gap analysis of the previous findings by KAI and developing approaches and testing procedures that could identify and verify possible failure mechanism(s).

Three critical tests were performed to clarify if hydrogen cracking was involved in the rapid crack growth: (1) slow strain rate tensile (SSRT) testing in NS4 solution under hydrogen charging condition; (2) SSRT in air, and (3) SEM characterization of the nature of blisters and cleavage.

Comparisons of the fracture surface morphology produced by SSRT tests and field failure indicated that hydrogen was not involved in the rapid crack propagation of Bison failure. SEM confirmed that the microvoids near the fracture surfaces were not hydrogen blisters but formed by severe plastic deformation. The cleavage reported by KAI was not because of the presumed hydrogen ingress but associated with the inherit nature of pearlite cracking. The investigations concluded that hydrogen played no role in any of the cracking steps.

Based on the above findings, further study proceeded to address the unresolved mechanism for rapid crack growth, including (1) characterization of fracture surfaces to determine the processes involved in the Bison failure; (2) determination of the possible mechanism for rapid crack growth; (3) small scale confirmatory testing to demonstrate that large crack growth by ductile tearing during hydrostatic test is possible, and (4) additional metallurgical testing for material qualification. The findings are summarized as follows:

1. As evidenced by detailed fractographic analysis, the fracture surface consisted of three zones that correspond to three processes involved in the Bison failure:

– Zone 1: 27% wt initial crack caused by mechanical damage and dent rebounding. The crack was underneath the gouge, about 10% wt deep, and demarcated by black stain on the fracture surface. The crack was associated with 17% wt metal loss (wall thinning) by gouging.

– Zone 2: subcritical crack growth from 27% wt to 85% wt by two different mechanisms:

    i. Zone 2a: a semi-elliptical-shaped region demarcated by presence of banded fracture surface alternating between microvoids (dimples) and quasi cleavage. Zone 2a is the one related to the rapid crack growth and was the focus of the study.

    ii. Zone 2b: a narrow (1mm wide) region demarcated by black stain, i.e., thick corrosion scale. The appearance and chemical composition of the corrosion scale of Zone 2b were distinctly different from Zone 1, suggesting that Zone 1 formed prior to pre-commissioning hydrostatic test while Zone 2b formed after hydrostatic test.

– Zone 3: final rupture occurred when the crack reached its critical size (3.8” x 85%wt) at the operating pressure.

2. The mechanism for rapid crack growth in Zone 2a was identified to be purely mechanical. Free of corrosion and corrosion scale on the fracture surface indicate that Zone 2a was not formed by progressive propagation of the crack from its initial depth of 27% wt to about 76% wt or more during six months operation; instead, it reflects a large crack increment by ductile tearing due to pre-commissioning hydrostatic testing followed by a pressure cycle from zero to MAOP.

– Fracture mechanics calculation showed that a large crack increment up to a depth of 61% wt - 71% wt is possible during pre-commissioning hydrostatic test at the pressure of 2004 psi.

– Fracture mechanics model also showed that a second increment up to a depth of more than 80% wt is possible after hydrostatic test followed by a pressure cycle from zero to MAOP (1440 psi).

– Due to uncertainties in dent-gouge geometry, residual stresses, and material properties, it is difficult, if not impossible; to precisely quantify crack increment by pre-commissioning hydrostatic testing.

– Finally, the crack reached its critical size by a small amount of crack increment, 1mm (0.04") or less, during six-month operation either due to corrosion or slow ductile tearing, or a combination. A flaw of this size would fail at the operating pressure as evidenced by the failure and fracture mechanics calculation.

3. The small scale single edge notched tensile tests (SENT) at a constant stress level of 94% SMYS demonstrated and provided a direct evidence that large crack growth by ductile tearing during hydrostatic test is feasible. The fracture surface morphology produced by ductile tearing test is identical to that produced by Bison failure (Zone 2a).

4. Metallurgical and mechanical testing confirmed that the material meets API 5L PSL2 specification for X70 as reported by KAI.

In summary, the root cause for Bison pipeline rupture was severe mechanical damage in the form of a gouged dent containing cracks. Hydrogen played no role in the Bison failure incident. The mechanism for rapid crack growth in Bison failure was determined to be purely mechanical. Free of corrosion and corrosion scale on the fracture surfaces indicates that the Zone 2a was not formed by progressive propagation of the initial crack during six months operation; instead it reflects a large crack increment by ductile tearing due to pre-commissioning hydrostatic testing followed by a pressure cycle from zero to MAOP. This conclusion is supported by fracture mechanics calculations; single edge notched tensile tests, and is consistent with the well documented phenomenon that time-dependent crack growth by slow ductile tearing could occur during hydrostatic test."

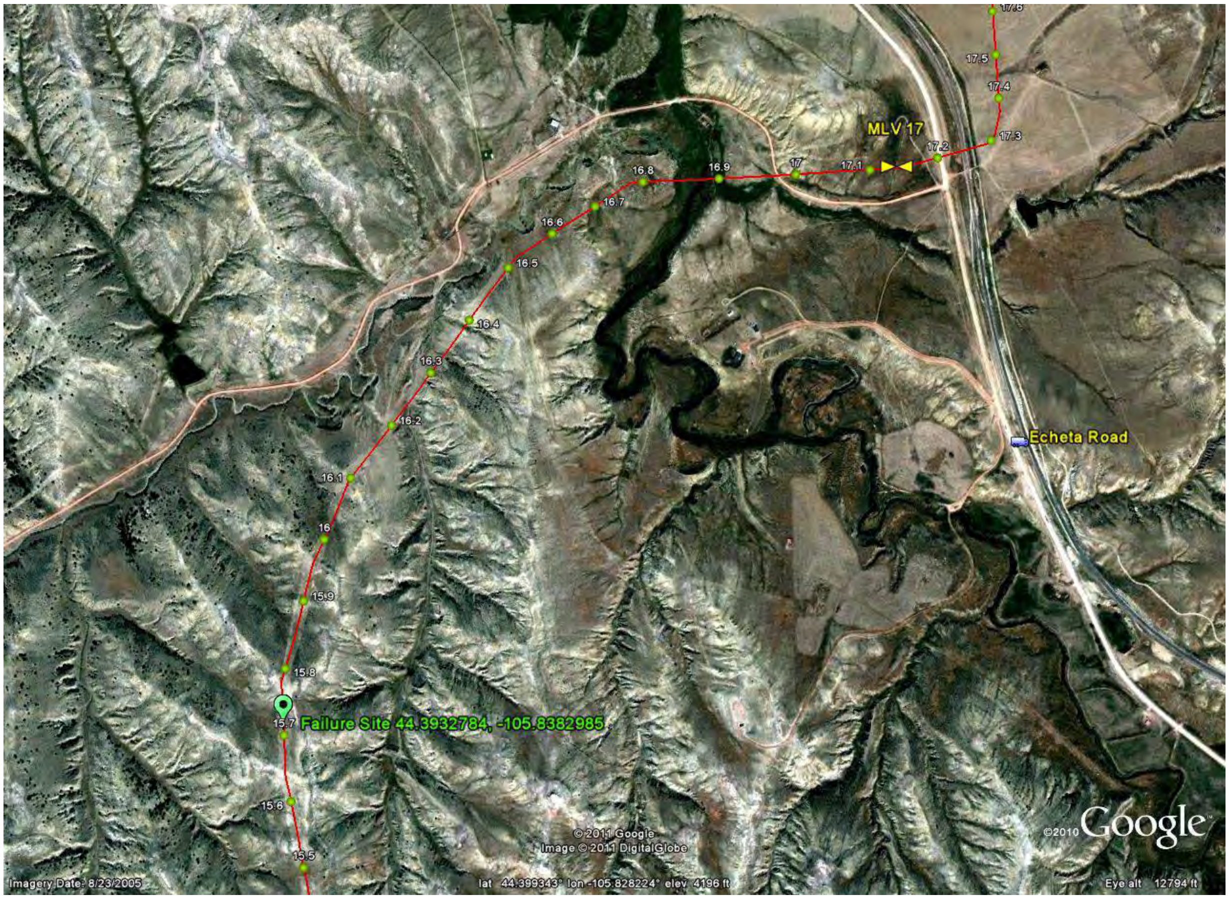
Conclusions:

PHMSA reviewed the final reports and held a meeting with TransCanada and representatives from the second laboratory in order to fully understand the testing preformed and the conclusions made. PHMSA concurs with the scientific methods utilized in the further testing as well as the conclusions drawn from the testing.

PHMSA finds that an anomaly was introduced to the pipe at the ultimate failure location during final phases of construction. This anomaly caused a dent with metal loss in the pipe wall. The post construction hydrotest caused the dent to reround and the damaged pipe to crack to a point just prior to failure. Subsequent commissioning and operation for 6 months caused the crack to propagate to failure with no additional outside forces acting on it.

<u>Appendices</u>

1. Maps and Photographs
2. NRC Report
3. Operator Accident/Incident Report to PHMSA
4. Metallurgical Analysis Report #1
5. Metallurgical Analysis Report #2



Google Map of Topography of release location NE of Gillette, WY.

Picture from Landowner's House immediately after rupture.

Picture from Landowner's House immediately after rupture.

Looking South from Rupture with long piece of ejected pipe in the foreground.

Looking North at Rupture Location with long piece of ejected pipe in the foreground.

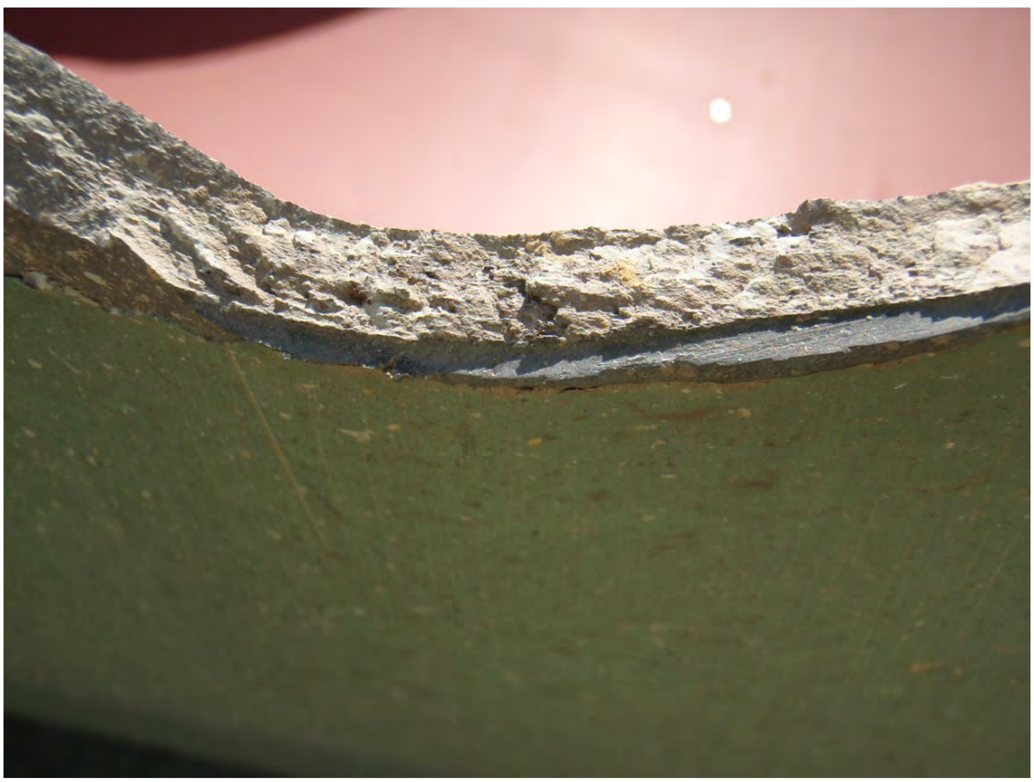
Close up of North end of failed pipe looking SE

Full rupture crater looking South

Coating repair and additional external damage (post rupture) on long piece of ejected pipe.

Close up of Probable Failure Initiation showing external damage and visible cracking.

Close up of Probable Failure Initiation showing external damage and visible cracking.



Close up of Probable Failure Initiation showing external damage.

TransCanada Metallurgist cleaning probable fracture initiation point with toothbrush and water.

Close-up TransCanada Metallurgist cleaning probable fracture initiation point with toothbrush and water.

Close-up of probable fracture initiation point after cleaning with measuring tape.

Close-up of probable fracture initiation point after cleaning with measuring tape.

Extreme Close-up of probable fracture initiation point after cleaning with measuring tape.

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

Incident Report # 983351

INCIDENT DESCRIPTION

*Report taken at 00:13 on 21-JUL-11
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident was discovered on 20-JUL-11 at 19:15 local time.
Affected Medium: AIR ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: BISON PIPELINE LLC
HOUSTON, TX

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

SEE LAT /LONG County: CAMPBELL
City: GILLETTE State: WY
Latitude: 44° 00' 23" N

Longitude: 105° 00' 50" W
PIPELINE MP 16.2

RELEASED MATERIAL(S)

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

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A RELEASE OF NATURAL GAS IN A PIPELINE DUE TO TWO JOINTS OF PIPELINE COMING OUT OF THE GROUND. THE CAUSE IS UNKNOWN AT THIS TIME.

INCIDENT DETAILS

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

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN

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

Damages: NO

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

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

PIPELINE IS ISOLATED.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: SUNNY, 90ºF

ADDITIONAL AGENCIES NOTIFIED

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

NOTIFICATIONS BY NRC

USCG ICC (ICC ONI)
21-JUL-11 00:25
CGIS RAO ST. LOUIS (COMMAND CENTER)
21-JUL-11 00:25
COLORADO INFO ANALYSIS CENTER (FUSION CENTER)
21-JUL-11 00:25
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
21-JUL-11 00:25
U.S. EPA VIII (MAIN OFFICE)
21-JUL-11 00:31
NE INFORMATION ANALYSIS CENTER (MAIN OFFICE)
21-JUL-11 00:25
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
21-JUL-11 00:25
NOAA RPTS FOR WY (MAIN OFFICE)
21-JUL-11 00:25
NTSB COMM. CTR (MAIN OFFICE)
21-JUL-11 07:53
DOI/OEPC DENVER (MAIN OFFICE)
21-JUL-11 00:25
WY DEPARTMENT OF ENVIRON QUALITY (MAIN OFFICE)
21-JUL-11 00:25
WYOMING CRIMINAL INTEL CENTER (SR INTELLIGENCE OFFICER)
21-JUL-11 00:25
WYOMING OFFICE OF HOMELAND SECURITY (OPERATIONS DIVISION)
21-JUL-11 00:25

ADDITIONAL INFORMATION

NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT # 983351 ***

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:**	08/16/2011
	No.	20110294 - 15608 (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 10 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

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

PART A - KEY REPORT INFORMATION

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

Last Revision Date:	09/10/2012
1. Operator's OPS-issued Operator Identification Number (OPID):	32487
2. Name of Operator	TRANSCANADA NORTHERN BORDER INC
3. Address of Operator:	
3a. Street Address	717 Texas Avenue
3b. City	Houston
3c. State	Texas
3d. Zip Code:	77002
4. Local time *(24-hr clock)* and date of the Incident:	07/20/2011 19:30
5. Location of Incident:	
Latitude:	44.39328
Longitude:	-105.8387
6. National Response Center Report Number (if applicable):	983351
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	07/21/2011 00:13
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):	50,555.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	41,938.00
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	Yes
- If No, Explain:	

- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	07/20/2011 19:40
15b. Local time pipeline/facility restarted	08/05/2011 19:30
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	0
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	07/20/2011 20:15
19b. Local time operator resources arrived on site	07/20/2011 20:15

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Incident onshore?	Yes
- Yes (Complete Questions 2-12)	
- No (Complete Questions 13-15)	
If Onshore:	
2. State:	Wyoming
3. Zip Code:	82716
4. City	Gillette
5. County or Parish	Campbell
6. Operator designated location	Milepost/Valve Station
Specify:	16.2
7. Pipeline/Facility name:	Bison Pipeline
8. Segment name/ID:	MLV 0 - MLV 17
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):	
12. Did Incident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
Name of body of water (If commonly known):	
Approx. water depth (ft) at the point of the Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Onshore Pipeline, Including Valve Sites
3. Item involved in Incident:	Pipe
- If Pipe – Specify:	Pipe Body
3a. Nominal diameter of pipe (in):	30
3b. Wall thickness (in):	.438
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	70,000
3d. Pipe specification:	API 5L
3e. Pipe Seam – Specify:	Single SAW

- If Other, Describe:	
3f. Pipe manufacturer:	Welspun
3g. Year of manufacture:	2007
3h. Pipeline coating type at point of Incident – 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. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	2010
5. Material involved in Incident:	Carbon Steel
- If Material other than Steel or Plastic – Specify:	
6. Type of Incident involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other – Describe:	
- If Rupture - Select Orientation:	Longitudinal
- If Other – Describe:	
Approx. size: in. (widest opening):	
by in. (length circumferentially or axially):	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Class Location of Incident:	Class 1 Location
2. Did this Incident occur in a High Consequence Area (HCA)?	No
- If Yes:	
2a. Specify the Method used to identify the HCA:	
3. What is the PIR (Potential Impact Radius) for the location of this Incident? Feet:	846
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	$ 234,550
7c. Estimated cost of gas released during intentional and controlled blowdown	$ 184,765
7d. Estimated cost of Operator's property damage & repairs	$ 4,280,685
7e. Estimated cost of Operator's emergency response	$ 10,000
7f. Estimated other costs	$ 1,990,000
Describe:	Testing and contingencies
7g. Estimated total costs (sum of above)	$ 6,700,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	1,340.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	1,440.00
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:	Automatic
5b. Type of downstream valve used to initially isolate release source:	Automatic
5c. Length of segment isolated between valves (ft):	96,626
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?	SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations)
- 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:	
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)*	Controller saw SCADA information showing unexpected pressure drop on Bison Pipeline and contacted upstream supplier. After contacting field operations, Controller recontacted upstream supplier of continued pressure loss , who shut in their compression, dropping flow into Bison Pipeline to zero.
- 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 – Material Failure of Pipe or Weld	**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
Material Failure of Pipe or Weld – 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	
- Other	Yes
- If Other, Describe:	Installation-related damage suspected during backfill
- 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	Yes
- Gouge	Yes
- 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	
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	Yes
Most recent year run:	2011
- 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

The Bison Pipeline experienced a rupture failure at approximate milepost 16.2 in Campbell County, Wyoming, at about 1930 hours on July 20, 2011. There area of the failure was remote from roads or structures resulting in damage restricted to the pipeline right-of-way. There were no injuries or fatalities. Preliminary examination of the pipe in the field and laboratory has indicated that the failure may have been the result of mechanical damage incurred during pipeline installation. The results of the studies have been finalized and have been submitted under separate cover, as part of the corrective action order.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	09/10/2012

Appendix Item

Final Report

Investigation of the Bison Pipeline Failure near Gillette, Wyoming

This document is on file at PHMSA