Transportation Safety Board of Canada

Bureau de la sécurité des transports du Canada

COMMODITY PIPELINE OCCURRENCE REPORT

NATURAL GAS PIPELINE RUPTURE

FOOTHILLS PIPE LINES (SASK.) LTD.

1,067-MILLIMETRE (42-INCH) EASTERN MAIN LINE

KILOMETRE POST 66 + 041

MAPLE CREEK, SASKATCHEWAN

15 FEBRUARY 1994

REPORT NUMBER P94H0003

Canada

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- conducting independent investigations and, if necessary, public inquiries into transportation occurrences in order to make findings as to their causes and contributing factors;
- reporting publicly on its investigations and public inquiries and on the related findings;
- identifying safety deficiencies as evidenced by transportation occurrences;
- making recommendations designed to eliminate or reduce any such safety deficiencies; and
- conducting special studies and special investigations on transportation safety matters.

It is not the function of the Board to assign fault or determine civil or criminal liability. However, the Board must not refrain from fully reporting on the causes and contributing factors merely because fault or liability might be inferred from the Board's findings.

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Synopsis

At approximately 1940 mountain standard time (MST), on 15 February 1994, a rupture and a fire occurred on the Foothills Pipe Lines (Sask.) Ltd. 1,067-millimetre (42-inch) natural gas pipeline at Kilometre Post 66 + 041 near Maple Creek, Saskatchewan.

The Board determined that the rupture was caused by the ductile fracture of a delamination in the mid-wall of the pipe. The delamination was produced by the diffusion of atomic hydrogen at inclusions in the pipe steel during normal pipeline operations.

Ce rapport est également disponible en français.

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1.0 Factual Information

1.1 The Accident

On 15 February 1994, at approximately 1940 mountain standard time (MST), TransCanada PipeLines Limited (TCPL) personnel at TCPL's Compressor Station No. 2, located at Burstall, Saskatchewan, observed a large fireball in the distance to the southeast of their location.

Shortly after this observation, the NOVA Gas Transmission (NOVA) Gas Control Centre (GCC) staff, located in Calgary, Alberta, detected a steady loss of pressure in the pipeline system of Foothills Pipe Lines (Sask.) Ltd. (FPL). The FPL system is operated by TCPL and the flow of natural gas through the FPL system is controlled by NOVA's GCC.

At 1955 MST, NOVA's GCC activated the NOVA emergency scan program to determine if an emergency situation existed on the FPL system. Shortly thereafter, NOVA's GCC confirmed that a line break had occurred on the FPL system.

At about this time, and in line with FPL's Emergency Response Manual, NOVA's GCC requested that Amoco Canada Petroleum Company Ltd. redirect all natural gas flows from the FPL system into the TCPL system at Empress, Alberta. At 2006 MST, NOVA also requested TransGas Ltd. to shut in the Crane Lake natural gas deliveries. Immediate action was taken to determine the nature of the pipeline problem and, if necessary, to re-route the natural gas flowing into the FPL pipeline system.

At the time of the incident, FPL's Compressor Station 392, located at KP 112 near Piapot, Saskatchewan, was off line and the station suction and discharge valves were closed. At approximately 2017 MST, Compressor Station 391, located at KP 22, was shut down by NOVA's GCC. Compressor Station 394, located at KP 260, was allowed to continue running until it shut down on low suction pressure to draft as much gas out of the line as possible and prevent it from flowing backwards through the line to the rupture site.

At approximately 2014 MST, NOVA advised FPL of a line break on FPL's pipeline system and that it had already initiated FPL's emergency response plan. At this time, and in accordance with the company's emergency procedures, TCPL's Station 392 personnel were dispatched to Station 391, to the Golden Prairie Sales Tap at KP 61, and to the main line isolation valves located at KP 52 and KP 82. Low pressure shut-down devices located at KP 52 and KP 82 initiated closure of these two main line valves when the internal pressure dropped to 2,800 kilopascals (kPa) (406 pounds per square inch (psi)). Based on computer simulations, it is estimated that these valves automatically closed at approximately 2023 and 2039 MST respectively.

At approximately 2115 MST, TCPL staff arrived at the rupture area, which was still burning, and confirmed its location as KP 66 + 041, approximately 35 kilometres (km) north of Maple Creek, Saskatchewan, in a community pasture approximately 4.7 km from the nearest residence.

At approximately 2125 MST, TCPL staff determined that the main line bypass valve located at KP 82 continued to permit natural gas to flow around this main line valve location and to feed the fire. The 323.9-millimetre (mm) Grove ball valve model B-5 (B-5 valve) (nominal pipe size (NPS) 12) had failed to seal properly. At 0220 MST, on 16 February 1994, the B-5 valve was effectively sealed by TCPL personnel using high-pressure grease which was injected into the valve seat to permit it to close and seal properly. At 0225 MST, 16 February 1994, the fire extinguished itself.

The pipeline was repaired using pre-tested pipe. The tie-in welds were 100 per cent X-ray inspected and returned to service on 18 February 1994.

1.2 Injuries

There were no injuries as result of this occurrence.

1.3 Damage to Equipment and Product Lost

Damage to the pipeline consisted of approximately 21.9 metres (m) (71.9 feet) of ruptured pipe which had split open in the longitudinal direction before being blown out of the pipeline a distance of approximately 125 m (410 feet). Associated with the failure was a fire which burned a pasture approximately 8.50 hectares (21.0 acres) in surface area located to the east and downstream of the rupture.

An estimated 9,915,000 cubic metres (m^3) (352,000,000 standard cubic feet) of sweet natural gas was consumed by the fire. An additional 368,000 m^3 (13,000,000 standard cubic feet) of sweet natural gas was released unburned to the atmosphere after having been used to purge the pipeline of water and air that entered during the repair.

Since sections of the undamaged pipeline were removed for analysis purposes, the pipeline was repaired using five joints of pipe totalling 56 m (183.73 feet).

1.4 Weather

The winds were from the west at approximately 30 to 50 km/h, the sky was clear and the temperature was approximately minus two degrees Celsius.

1.5 Commodity Pipeline Operations

The rupture occurred on the eastern leg of the pre-built portion of the Alaska Natural Gas Transportation System (ANGTS). This portion of the ANGTS, referred to as FPL, was constructed during the period 1981-1982 and was placed in service on 01 September 1982. There are compressor stations on this section of the pipeline system at KPs 22, 112, 198 and 258. The flow of natural gas in the system is controlled through NOVA's GCC located in Calgary, and NOVA acts as an agent for FPL in Alberta. This pipeline has been transporting sweet natural gas (free of hydrogen sulphide gas) since it was placed in service.

The FPL pipeline system measures 259 km (160.9 miles) long and extends from the Alberta border near Burstall to the Canada/U.S. border near Monchy, Saskatchewan.

On the day of the accident, the pipeline was transporting sweet natural gas at a daily flow rate of approximately 36,600,000 m^3 (1.3 billion cubic feet), at a compressor station pressure of 8,690 kPa (1,260 psi), and at a flowing gas temperature of 17.7 degrees Celsius (63.9 degrees Fahrenheit). The pressure in the pipeline at the time of the occurrence and at that location is estimated to have been 8,322 kPa (1,207 psi).

1.6 Particulars of the Ruptured Pipeline

The rupture initiated in a section of the FPL pipeline system approximately 1 m upstream from a field girth weld. The rupture propagated upstream approximately 10 m before arresting in the initiation joint of the pipe. The rupture also propagated downstream, crossing the girth weld and arresting approximately 10 m into the next joint of pipe. Fragments of a saddle weight were found on the ground around the rupture site.

The pipe was designed to meet the requirements of FPL's Engineering Specification P-100 titled *Specification for High Strength Steel Line Pipe 457 mm and Larger in Diameter* and dated 22 August 1980. The pipe was grade 483 megapascals (MPa) (grade X70) steel, had a double-submerged arc welded longitudinal seam, a 12-mm (0.427-inch) wall thickness and a 1,067-mm (NPS 42) outside diameter. The pipe was manufactured to meet the requirements of standards CAN/CSA-Z245.1 and CAN/CSA-Z245.2 of the Canadian Standards Association (CSA). Additional quality requirements, such as chemical composition restrictions, additional heat analysis and mechanical testing, were imposed on the pipe manufacturer by FPL's Engineering Specification P-100. The pipe steel manufacturer had rolled four joints of pipe from each ingot in 1981. The pipeline was coated with a primer and a double layer of polyethylene tape.

This section of the pipeline was covered with 1.5 m of soil which had a high sand content. The area had a high water table and, at one time, had been an ancient seabed. While there was no direct evidence found at the accident site which would indicate that the site was situated in an ancient salt water lake or sea, it is noted that sediments of the Western Canada Sedimentary Basin were deposited in an ancient salt water sea.

Because of the high water table, the pipeline required saddle weights. The saddle weights were placed at 8-m (26.25-foot) intervals at this location. Each weight measured approximately 1.7 m wide by 1.8 m long by 1.4 m high and weighed 5,150 kilograms (kg) (11,354 pounds). The saddle weights, commonly referred to as "sulphurcrete", were made up of a mixture of liquid molten sulphur, concrete aggregate and a bonding polymer. The inside surface of the weight surrounding the pipeline was lined with a felt padding.

After installation in 1982, the pipeline was hydrostatically tested with water and granted a maximum allowable operating pressure (MAOP) of 8,690 kPa (1,260 psi).

Approximately 32 m (105 feet) of the double-wrapped polyethylene protective tape coating was lost because of the force of the explosion and ensuing fire. The coating on the sections adjacent to the rupture site showed good adherence to the pipe and the intact pipe was examined for quality of the remaining coating. Tape coating defects were identified and consisted of three types:

1. "holidays" (thinning or microholes);

2. areas of general disbondment; and

3. wrinkles, perforations and/or tears.

Four areas of general disbondment of the tape containing "holidays" were identified at regular intervals along the remaining pipe adjacent to the fracture area. These areas coincided with the location of the saddle weights on the pipe.

During testing in 1990 at KP 66, the "off" potential of the cathodic protection (CP) system averaged minus 1,180 millivolts (mV) and the "on" potential of the CP system averaged minus 1,500 mV. However, during the same time span, CP fluctuations were observed upstream at KP 52. The exact cause of these fluctuations was never identified, but a FPL corrosion technician stated that fluctuations in soil moisture could affect the CP readings by as much as 200 mV.

As part of its ongoing operations during 1991, FPL performed an internal inspection of its pipeline system using a metal loss detector to identify external corrosion. The results of this inspection indicated that there was not a corrosion problem at that time.

1.7 Metallurgical Testing

A metallurgical analysis of the fractured area of the pipe determined that the rupture initiated at the mid-wall of the pipe surface under or adjacent to a saddle weight. Hydrogen induced cracking (HIC) has been identified as the mechanism producing a mid-wall void in the pipe which, along with local hydrogen embrittlement, led to the rupture (TSB Engineering Report No. LP 25/94).

In addition to the mid-wall void which led to the failure, the metallurgical investigation found the following other pipe defects:

a) two small areas of HIC at the mid-wall of the pipe; and

b) several hydrogen blisters on the surface of the pipe wall.

The metallurgical examination also revealed type II elongated manganese sulphide inclusions. The chemical analysis confirmed that the pipe met all applicable material specifications. However, the amount of calcium added to obtain the desired toughness properties was not sufficient to fully spheroidize these inclusions. It should be noted that there is presently no requirement to fully spheroidize inclusions in line pipe steel purchased to meet the specifications of standard CAN/CSA-Z245.1 and intended for sweet natural gas service.

1.8 Hydrogen Induced Cracking (HIC)

HIC requires both a source of atomic hydrogen and a mechanism to drive or permit the hydrogen atoms to enter the steel. Hydrogen atoms diffuse through the pipe wall and become entrapped at heterogeneous sites in the steel, leading to HIC at the mid-wall and hydrogen blisters on the pipe wall surface. The initiation of HIC blisters and associated cracks on the pipe wall surface are indications of the presence of hydrogen. The susceptibility of line pipe steels to HIC, also called step wise cracking (SWC), depends on several metallurgical and environmental factors. These factors must occur concurrently to cause a HIC flaw to initiate and to propagate to failure. These factors are as follows:

i) the external polyethylene coating must be damaged;

ii) atomic hydrogen must be produced at the pipe surface from the CP system and/or from bacterial activity;

iii) atomic hydrogen must be continuously diffusing into the steel due to the presence of a surface "poison";

iv) the microstructure of the steel must be susceptible to hydrogen entrapment, namely the steel must have heterogeneous features in the microstructure, such as type II elongated manganese sulphide inclusions and bands of carbon rich material;

v) molecular hydrogen gas must be forming and accumulating along the heterogeneous features; and

vi) in order for rupture to occur, the mid-wall crack must propagate to the inner or outer surface of the pipe and the length of this surface breaking flaw must be greater than the critical flaw size at the operating pressure and toughness of the pipeline.

1.9 Other Factors Affecting HIC

Other factors which can contribute to the reaction and growth of HIC are as follows:

i) Aggressive ions such as chlorides left over from salt deposits combining with water to produce atomic hydrogen.

ii) A current flow from the CP system at the area of damaged coating.

iii) The presence of a "poisoning" agent such as sulphide produced by anaerobic bacteria which allows for easier atomic hydrogen absorption into the pipe steel.

iv) The size of the disbondment or damage to the tape coating.

1.10 Follow-up Activities

FPL removed 150 m of pipe and 17 saddle weights immediately downstream of the occurrence site. The intent of this additional work was to ensure the overall structural integrity of the pipeline. Extensive sampling and studying of the following were undertaken:

i) the soils adjacent to the pipe;

ii) the ground water around the pipe;

iii) the corrosion deposits on the pipe surface;

iv) the electrolyte under the polyethylene coating;

v) the intact and disbonded coating; and

vi) yellow exudate seeping from the sulphurcrete weights.

The evaluations revealed:

i) 350 indications of HIC blisters on the pipe wall surface;

ii) one location of stress corrosion cracking (SCC);

iii) general disbondment of the polyethylene coating under the saddle weights, with the greatest disbondment in high-water areas;

iv) iron sulphide in the soil adjacent to the saddle weights and under the disbonded polyethylene coating;

v) chloride ions in the ground water surrounding both the pipe and the saddle weights;

vi) hydrogen-sulphide odour near and/or under some weights;

vii) high levels of sulphur reducing anaerobic bacteria close to both the pipe and the saddle weights; and

viii) a yellow liquid draining from the saddle weights was subsequently identified as a polysulphide material.

1.11 Previous Accidents of a Similar Nature

HIC has long been a problem encountered with the handling of sour natural gas (i.e., high hydrogen sulphide content). As a result of chemical reactions involving hydrogen sulphide in sour gas pipelines, atomic hydrogen penetrates through the pipe wall from the inside to produce zones of HIC. However, only in very rare situations has HIC affected the pipe wall structure in sweet natural gas (i.e., natural gas free of hydrogen sulphide gas).

In 1991, NOVA experienced one leak in its Alberta system attributed, in part, to the same type of HIC found on the subject section of FPL. This leak occurred on the NOVA Gas Western Alberta System which is 914 mm (36 inches) in diameter, has a pipe grade for the steel of 483 MPa and is coated with polyethylene tape. At the time of the leak, this section of the system had been in service for 15 years. The metallurgical examination found that the HIC had occurred under a saddle weight and that HIC blisters on the surface of the pipe wall were present.

Two other similar failures have occurred on pipeline systems in North America. Each of these known failures was the result of a combination of several factors which differed from case to case. While there is some preliminary evidence that the sulphurcrete saddle weights used on FPL's line may have contributed to failure, it should be noted that other pipelines which used this material for saddle weights have been in service longer than the FPL line and have not experienced any similar cracking. None of the other three failures mentioned above involved sulphurcrete.

2.0 Analysis

2.1 Introduction

The metallurgical examination identified HIC as the cause of the pipeline weakness that led to the failure. The pipeline rupture and loss of internal operating pressure were immediately recognized, triggering a series of emergency procedures. Upon confirmation that a rupture had occurred, FPL's emergency response procedures were put into effect. However, there was a time delay before initiation of the emergency procedures and the flow of gas to the occurrence site was not immediately halted due to mechanical problems with the seats on the bypass valve at KP 82.

The analysis will focus on the systems and procedures employed by TCPL and FPL in reaction to the sudden drop in pipeline pressure and the metallurgical and environmental conditions that led to the pipe deterioration.

2.2 Consideration of the Facts

2.2.1 Emergency Procedures

2.2.1.1 Isolation Valves

The termination of the natural gas flow was delayed for approximately 3.5 hours due to mechanical problems with the valve seats on the bypass line at KP 82. Though a TCPL employee had been dispatched to confirm closure of the valves at KP 82 in line with established FPL procedures, approximately three hours later, a TCPL crew had to be re-deployed to re-seal the bypass valve. Since there had been insufficient differential pressure across the KP 82 valves to cause a detectable flow of gas through the bypass valve, the initial employee was assigned other duties and left the KP 82 valve site. However, after a period of time, TCPL staff observing the fire at the accident site determined that natural gas was leaking past the KP 82 isolation valves and dispatched a second crew which, upon their arrival at the KP 82 valve site, proceeded to seal the bypass valve. FPL's emergency response procedures stress the need to ensure that main line and bypass valves are fully closed during an emergency situation. Isolation valves ensure that product flow has been stopped and permit the accident site and the immediate surrounding areas to be safely and effectively protected from the dangers associated with the releasing product. However, FPL's emergency procedures did not contain a corporate policy requiring that the first employee at a valve isolation site remain and ensure full closure of the isolation valves before leaving to perform other duties. The need for this type of policy is especially important during an emergency situation where the isolation valves will be exposed to extreme differential pressure when acting as a barrier to stop the sudden surge of natural gas to the accident site and limit the amount of product escaping. Had the TCPL employee remained at the valve isolation site, the improperly sealed bypass valve would have been discovered sooner and remedial measures could have been expeditiously initiated. With the discovery that the bypass valve would not seat properly, emergency response crews were required to initiate a closure of the bypass valve. This additional activity could have been avoided if the bypass valve had been better maintained to prevent this type of problem. The degree of hazard after a rupture would be less if pipeline companies had in place maintenance and emergency procedures that would ensure quick and complete isolation of the ruptured pipe section.

2.2.1.2 Emergency Response

In spite of the early indications of a loss of pipeline pressure indicative of a rupture or leak, TCPL employees responsible for responding to emergency situations on the FPL pipeline were not advised of the rupture until 24 minutes after it occurred and 4 minutes after confirmation of the rupture by NOVA's GCC. The need for immediate notification to company personnel is paramount. While this delay did not result in any loss of containment of the fire at the occurrence site and to the surrounding area, it did translate into a tardy initiation of FPL's emergency response plan. The record shows that, immediately upon confirming that a rupture had occurred, and in accordance with established emergency response procedures, NOVA's GCC took action to re-route the natural gas flowing into the ruptured pipe, notify the TCPL Shaunavon office to begin the mobilization of field personnel and notify the Foothills Head Office personnel. However, for safety purposes, the earlier indications of pressure loss on the FPL system, when combined with field observations of an explosion by the TCPL staff, should have resulted in an immediate mobilization of TCPL's field staff located at Burstall, Saskatchewan. Consequently, this delay translated into a slowness in providing advice and guidance to local first responders and in ensuring that the flow of natural gas to the occurrence site was isolated.

2.2.2 Hydrogen Induced Cracking (HIC)

The existence of HIC and its growth are dependent on the factors outlined in subsection 1.8. All these factors were found at the rupture location.

2.2.2.1 Polyethylene Coating

The polyethylene tape coating which was the prevailing standard at the time of the construction of the FPL pipeline displayed numerous areas of disbondment and coating damage. Such coatings are now known to have a tendency to disbond and to break at locations of high external stress. In the immediate area of the rupture location, there were numerous areas of coating disbondment and coating damage. Much of the coating damage was concentrated around or near the saddle weights. Seasonal fluctuations in the water table, normal operating oscillations of the pipeline, and high external stress due to the interaction of the pipe, the saddle weights and the soil were sufficient to produce the disbonding and fracturing of the external coating.

2.2.2.2 Hydrogen Source

Both atomic and molecular hydrogen would be in abundant supply in the ground water in which this portion of the pipeline was continuously immersed. The CP system tends to concentrate atomic hydrogen both at areas of broken coating and at areas of disbondment, which also allows hydrogen free access to the pipe surface. Atomic hydrogen can also be produced by electrochemical processes involving the CP systems, directly and/or indirectly by bacterial action. When the pipe-to-soil potential of the CP system exceeds a level generally known as the hydrogen over potential (usually an "off" potential of CP of about minus 1,200 mV), the level of atomic hydrogen production may result in hydrogen entry into the steel. CP levels on the FPL pipeline were at approximately minus 1,185 mV. In any event, bacterial action produces hydrogen sulphide which in turn reacts to form atomic hydrogen. The polyethylene coating used on this pipeline is impermeable to CP current. The presence of saddle weights on the pipeline can also block the CP current, thus limiting the areas where CP current could act as a hydrogen source to the coating holidays (wrinkles, breaks or tears) located between or under weights, but near the edge of the weight. The presence of a structure, such as a saddle weight, near a break in the protective coating, can also result in a difference in the electrochemical potential between the pipe-to-structure and the pipe-to-soil environments which could lead to the production of atomic hydrogen. Considering all of the sources, bacterial action is therefore a more probable source of the amount of atomic hydrogen necessary for this type of accident to occur.

2.2.2.3 Saddle Weight Composition

The problems associated with sulphur compounds and their effects on buried structures are well known. "Sulphur compounds" include sulphides, sulphites and thiosulphates. Sulphur compounds act as a "poisoning" agent to ease the entry of atomic hydrogen into the pipe steel, and to accelerate the reaction and growth of HIC in the steel. Sulphur compounds were in abundant supply at the occurrence site. An obvious source of these sulphur compounds is the "sulphurcrete" saddle weights which are different from the standard concrete-mix type weights used by the pipeline industry and which were found to be leaking sulphur. Thus the composition of the saddle weights is a potential contributor to the presence of poisoning agents which accelerated the growth of the HIC.

2.2.2.4 Cathodic Protection (CP)

FPL performed annual surveys of the system to ensure that the pipeline was protected by an appropriate level of CP. Although there were fluctuations in the CP levels from year to year and place to place, all readings did meet the minimum minus 850 mV National Association of Corrosion Engineers (NACE) criterion and FPL states that the fluctuations were within the range expected to occur as a result of seasonal and annual changes in soil moisture contents. As a result, no follow-up activities were undertaken by FPL with respect to the CP system. Given the location of the pipeline in a high water table area, the resultant pipe movement, and the normal protective coating stresses that arise from seasonal and operational changes, these facts should have been reason enough to prompt follow-up activities by FPL to identify the reason for the CP change.

2.2.2.5 Location of the Pipeline

The occurrence site is located in an ancient seabed. This location was found to contain chloride ions which can accelerate the production of hydrogen and the growth of HIC.

2.2.2.6 Anaerobic Bacteria

The presence of high levels of anaerobic bacteria at the occurrence site may in part be attributed to agricultural activities over and around the pipeline and also in part to the polysulphide leaking from the saddle weights as evidenced by the discovery of iron sulphide and hydrogen sulphide in the soils around the pipe. Anaerobic bacteria can initiate and accelerate chemical reactions which produce hydrogen as a by-product. They can also contribute directly to the initiation of corrosive reactions which attack the surface of the pipe and encourage the absorption of hydrogen into the steel. This bacterial effect can also occur under disbonded coatings meaning that the pipe surface underneath the coating would not be protected by the CP system.

2.2.2.7 Metallurgy of the Pipe

The metallurgical examination of the steel from the pipeline found evidence of three HIC cracks at the mid-wall and numerous sites of hydrogen blisters on the pipe surface at the accident site and immediately downstream. The susceptibility of the line pipe to these two types of HIC depends on several metallurgical and environmental factors, which must occur concurrently. However, the most important of these factors is a steel microstructure which is susceptible to hydrogen entrapment. That is, the steel acts like a filter that permits atomic hydrogen to be trapped on the inside of the steel at the inclusions and bands.

The metallurgical examination observed type II elongated manganese sulphide inclusions and bands of carbon rich material in the subject failed pipe. Chemical analysis of the steel indicated that insufficient calcium had been added to the steel. However, chemical analysis done subsequent to the rupture indicated that, while the pipe met the applicable standard at the time of purchase, the amount of calcium added was not sufficient to fully modify the shape of the manganese sulphide inclusions and the bands of carbon rich material. Inclusions of manganese sulphide and bands of carbon rich material were produced during the pipe steel fabrication. The presence of these types of bands and inclusions can be a direct contributing factor for the entrapment of atomic and molecular hydrogen at these locations.

For new steel fabrication, this type of problem can be corrected by controlling the microstructure to produce one which is more uniform and by lowering the sulphur content of the melt. However, the solutions of microstructure adjustment are not available to an existing pipeline which has been found to have this type of microstructure. Instead, an existing pipeline company is required to initiate a comprehensive inspection program which reduces and/or eliminates all potential sources of hydrogen that will become entrapped in the pipe wall.

The first indication of hydrogen present in the steel may be the presence of hydrogen blisters on the pipe surface. The fact that hydrogen blisters are present in a particular pipe section should be cause to carry out an ultrasonic or other type of non-destructive inspection to determine if HIC cracks are present at the mid-wall of the pipe. Once advanced internal inspection devices are available to perform this type of inspection, in the interest of safety, they should be utilized. Should HIC crack(s) be identified in a section of the pipeline system, this should be cause to immediately replace this section of pipe in the interest of safety.

3.0 Conclusions

3.1 Findings

1. The pipeline rupture initiated at the mid-wall of the pipe steel under or adjacent to a saddle weight.

2. Hydrogen induced cracking (HIC) has been identified as the mechanism that produced this mid-wall void.

3. One location of mid-wall HIC, consisting of two separate cracks, was found in the rupture initiation joint and one additional mid-wall HIC feature was found in the upstream arrest joint of pipe.

4. The growth of the mid-wall HIC cracking feature can be accelerated by the presence of a large number of HIC blisters such as were found on the surface of the pipe wall at the rupture site.

5. There was a 24-minute delay in activating FPL's emergency response plan and alerting the emergency crews about the rupture even though the crews could observe the fire at the accident site from their maintenance base 80 km away.

6. Due to mechanical problems with the main line bypass valve seat at Kilometre Post 82, three and one-half hours were required to isolate the flow of natural gas.

7. The polyethylene tape coating disbonded from the pipe and was perforated as a result of pipe movement, circumstances which permitted free hydrogen to come into contact with the pipe surface.

8. Hydrogen was produced at the pipe surface from either the cathodic protection system and/or from anaerobic bacterial activities.

9. The diffusion of hydrogen into the steel surface was continuous, and various "poisons", possibly induced by the sulphurcrete saddle weights, accelerated the reaction and growth of HIC.

10. The microstructure of the steel contained type II elongated manganese sulphide inclusions and bands of carbon rich material, which made the microstructure of the steel susceptible to hydrogen entrapment.

11. The chemical analysis of the pipe steel indicated that there had been insufficient calcium added to the steel melt before pipe fabrication to spheroidize the manganese sulphide inclusions.

12. One location of stress corrosion cracking was identified in the adjacent, downstream section of pipe.

3.2 Cause

The rupture was caused by the ductile fracture of a delamination in the mid-wall of the pipe. The delamination was produced by the diffusion of atomic hydrogen at inclusions in the pipe steel during normal pipeline operations.

4.0 Safety Action

4.1 Action Taken

4.1.1 Follow-up by Foothills Pipe Lines (Sask.) Ltd. (FPL)

FPL has indicated involvement in the following actions:

- the modelling of hydrogen induced cracking susceptible environments, based on an analysis of soil, soil gas, ground water samples, and ground water saturation levels, to determine all aspects and interrelations of the electrical, chemical and bacteriological processes that ultimately led to the failure of Kilometre Post (KP) 66;

- removal of 450 m of pipe from three Alberta locations where there were similarities to the site of the KP 66 failure. To date, symptoms of HIC, similar to those observed at the rupture site, have not been found; however, a few small surface blisters were detected;

- research into the mechanism involved in charging hydrogen into steel, the development of a "fault-tree analysis" to predict HIC susceptibility on the basis of environmental parameters, and the determination of hydrogen permeation rates through steel based on the prevailing environmental conditions (including applied cathodic protection, pH, presence of sulphur and anaerobes);

- research into the diffusion of hydrogen into a mid-thickness crack of the steel and the growth of the crack as a function of the surface hydrogen activity, toughness, and temperature (which resulted in this work being integrated with the on-going development of a three-dimensional finite element model of HIC at a Canadian University);

- development of a risk assessment model, based on the mechanistic model of hydrogen damage, to prioritize saddle weight sites for HIC testing;

- participation in industry discussions on the development of an in-line inspection tool to detect hydrogen cracks.

4.2 Action Required

4.2.1 Hydrogen Induced Cracking (HIC) in Steel Pipe

Historically, HIC has been associated with the transmission of sour gas. As such, the manufacturing standard for pipe intended for sour gas service requires full spheroidization of non-metallic inclusions so the pipe is HIC resistant. Pipe to be used in the sweet gas industry is not required to undergo the same manufacturing process.

The pipe that failed in this occurrence met the then applicable CSA standard for sweet gas (standard CAN/CSA-Z245.2-M1979 Grade 483 Category II) at the time of its manufacture. Testing of the pipe subsequent to the occurrence revealed that the calcium level was too low to spheroidize and modify the sulphides to preclude inclusions in the pipe. As a result, sulphides catalyzed the exterior surface of the pipe, promoting the absorption of atomic hydrogen into the steel wall of the pipe. The hydrogen was then trapped by the inclusions.

It would appear that the difference in the manufacturing standards of steel pipe in sour or sweet gas service was based on the assumption that HIC was mainly a function of the chemical characteristics of the commodity being carried in the pipe. However, it is now apparent that certain subsurface environmental conditions are also conducive to corrosive reactions on the surface of the pipe, allowing atomic hydrogen to be absorbed through the exterior walls of the pipe if the protective coating of the pipe is breached.

Given that steel pipe may still be manufactured in Canada to a standard that does not provide adequate resistance to HIC, the Board recommends that:

> The National Energy Board, in conjunction with the Canadian Standards Association, re-evaluate the standards for steel pipe manufacturing with respect to the prevention of hydrogen entrapment within the pipe wall.

P95-01

FPL has identified other locations on its pipeline system where soil conditions were similar to those found at the site of this occurrence and where the pipe may also be susceptible to HIC. Since HIC was thought to be associated mainly with the transmission of sour gas, other companies transporting sweet gas may have also installed pipe manufactured to standard CAN/CSA-Z245.2-M1979 Grade 483 Category II, and have pipelines constructed in environments where there is a potential for HIC. Therefore, the Board recommends that:

> The National Energy Board identify and undertake corrective measures for pipelines manufactured to standard CAN/CSA-Z245.2-M1979 Grade 483 Category II operating in environments where there is a potential for hydrogen induced cracking.

P95-02

This report concludes the Transportation Safety Board's investigation into this occurrence. Consequently, the Board, consisting of Chairperson, John W. Stants, and members Zita Brunet and Hugh MacNeil, authorized the release of this report on 23 August 1995.

Appendix A - Glossary

ANGTS	Alaska Natural Gas Transportation System
B-5 valve	Grove ball valve model B-5
CP	cathodic protection
CSA	Canadian Standards Association
FPL	Foothills Pipe Lines (Sask.) Ltd.
GCC	Gas Control Centre
HIC	hydrogen induced cracking
kg	kilogram(s)
km	kilometre(s)
KP	Kilometre Post
kPa	kilopascal(s)
m	metre(s)
m^3	cubic metre(s)
MAOP	maximum allowable operating pressure
mm	millimetre(s)
MPa	megapascal(s)
MST	mountain standard time
mV	millivolt(s)
NACE	National Association of Corrosion Engineers
NOVA	NOVA Gas Transmission
NPS	nominal pipe size
psi	pound(s) per square inch
Sask.	Saskatchewan
SCC	stress corrosion cracking
SWC	step wise cracking
TCPL	TransCanada PipeLines Limited
TSB	Transportation Safety Board of Canada

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