Transportation Safety Board of Canada

Bureau de la sécurité des transports du Canada

PIPELINE INVESTIGATION REPORT
P09H0074

NATURAL GAS PIPELINE RUPTURE

TRANSCANADA PIPELINE INC.
914-MILLIMETER-DIAMETER PIPELINE
LINE 2 – MLV 107-2 + 6.031 KM
NEAR ENGLEHART, ONTARIO
12 SEPTEMBER 2009

Canada

Natural Gas Pipeline Rupture

TransCanada Pipeline Inc.
914-Millimeter-Diameter Pipeline
Line 2 – MLV 107-2 + 6.031 KM
Near Englehart, Ontario
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Summary

At approximately 1206 Eastern Daylight Time, on 12 September 2009, TransCanada's Gas Control received notification from the Englehart Fire Department through its Emergency Notification Line of an explosion and fire south of its Compressor Station 107, located near Swastika, Ontario. At the time of the occurrence, TransCanada was transporting sweet natural gas. Escaping gas from a pipeline rupture had ignited, resulting in the explosion. A large crater was created and two sections of pipe broke from the system, with one section being ejected approximately 150 metres from the rupture site. There were no injuries.

Ce rapport est également disponible en français.

Other Factual Information

The Accident

Just prior to the accident on 12 September 2009, the TransCanada Pipeline Inc. (TCPL) pipeline system had been operating normally. The operating pressure and temperature at this location was estimated to be 6869 kilopascals (kPa) (approximately 1000 pounds per square inch) and 38.6 degrees Celsius. For this section of TCPL's pipeline system, the maximum operating pressure (MOP), as approved by the National Energy Board (NEB), is 6895 kPa.

In the vicinity of the occurrence, there are three parallel pipelines buried approximately 0.914 meters (m) below ground, spaced approximately 10 m apart. Just before the occurrence, the flow rate between Compressor Station 107 and Compressor Station 110 was approximately 13,500,000 cubic metres per day (m^3/day) or 480 million cubic feet per day. The volume of natural gas lost during the occurrence was approximately 3,420,000 cubic metres.

Shortly before noon [1], TCPL Line 100-2 failed approximately 6.0 kilometres (km) downstream of Compressor Station 107 between Main Line Valve (MLV) 107-2 and 108-2 (see Figure 1). The failure resulted in an explosion and fire. Aerial assistance from the Ministry of Natural Resources' Aviation, Forest Fire and Emergency Services (AFFES) program was required to coordinate the suppression of the extensive brush and grass fires. Approximately 25 hectares of forest and grassland were burned. AFFES remained on site for 2 days to ensure that the fire had been completely extinguished by detecting, monitoring, and suppressing ground fires as they occurred.

Although the area is sparsely populated, four families in the vicinity were evacuated for 2 days as a safety precaution. Minor exterior damage occurred to a house, located approximately 320 metres (m) north of the pipeline rupture. The nearest town to the occurrence site is Englehart, Ontario, with a population of 1500 and located approximately 12 km southeast.

[1] All times are Eastern Daylight Time (Coordinated Universal Time minus 4 hours).

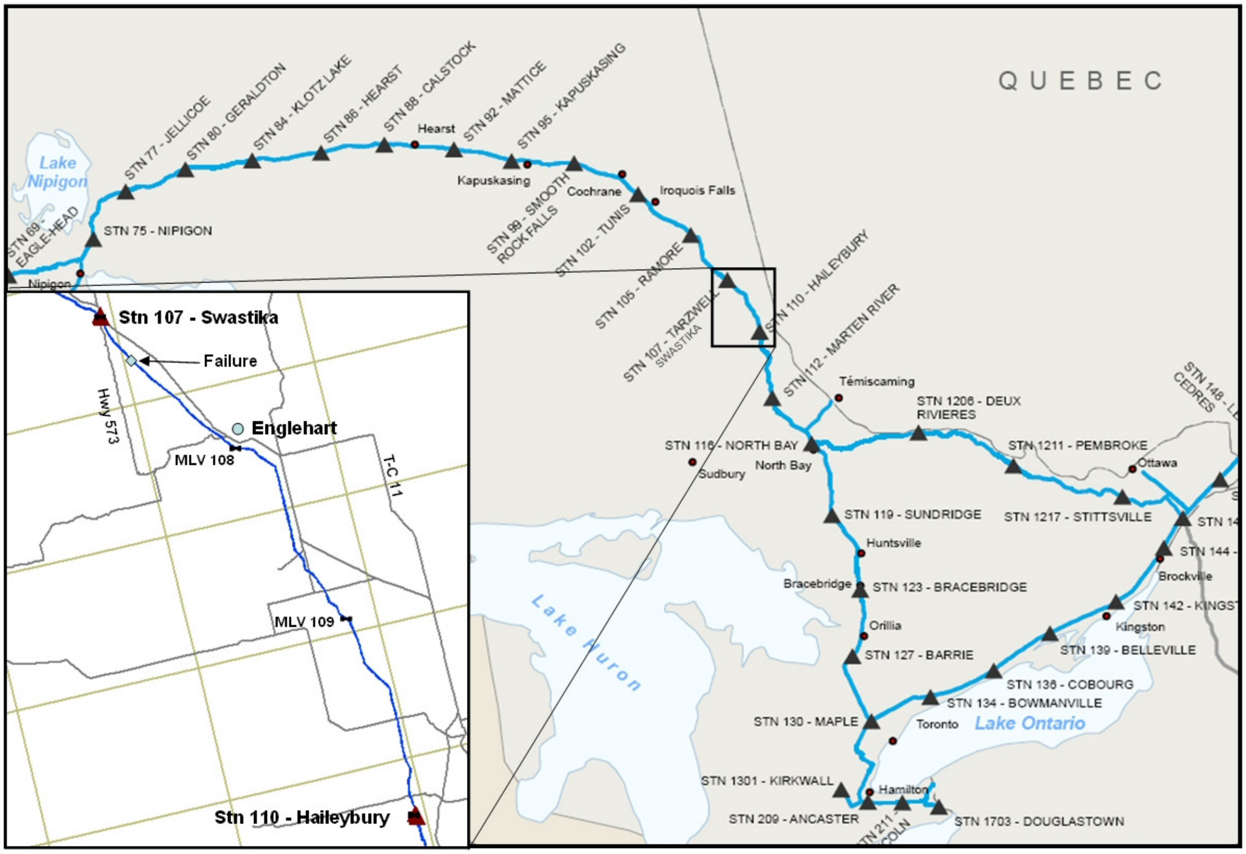

Figure 1 – Location of Pipeline Occurrence

Actions by Gas Control Operator

At 1206, having just received telephone notification of an event on the system, TCPL's Gas Control operator (the operator), based in Calgary, Alberta initiated the established procedure for verifying pipeline breaks. The operator reviewed the supervisory control and data acquisition (SCADA) telemetry. This review confirmed that there had been an abnormal pressure drop in this section of pipeline. The initial pressure drop was not sufficient to trigger the SCADA system's audible alarm. However, shortly afterwards, the SCADA system did produce an alarm. Additional telephone notifications were also being received from the general public concerning this occurrence.

At 1208, the operator initiated the remote "ISOLATE ALL" command feature at Station 107. The SCADA telemetry confirmed the isolation of all MLVs at the station. At 1210, the operator initiated the remote "ISOLATE ALL" for Station 110. The SCADA telemetry confirmed the isolation of all MLVs and associated side-valves. These actions isolated the three pipelines between stations 107 and 110 (see Figure 2). These pipelines were also isolated from each other by virtue of the closed tie-over valves between the pipelines, which allow for the movement of natural gas between the pipelines when required. The flow of natural gas was effectively stopped between stations 107 and 110.

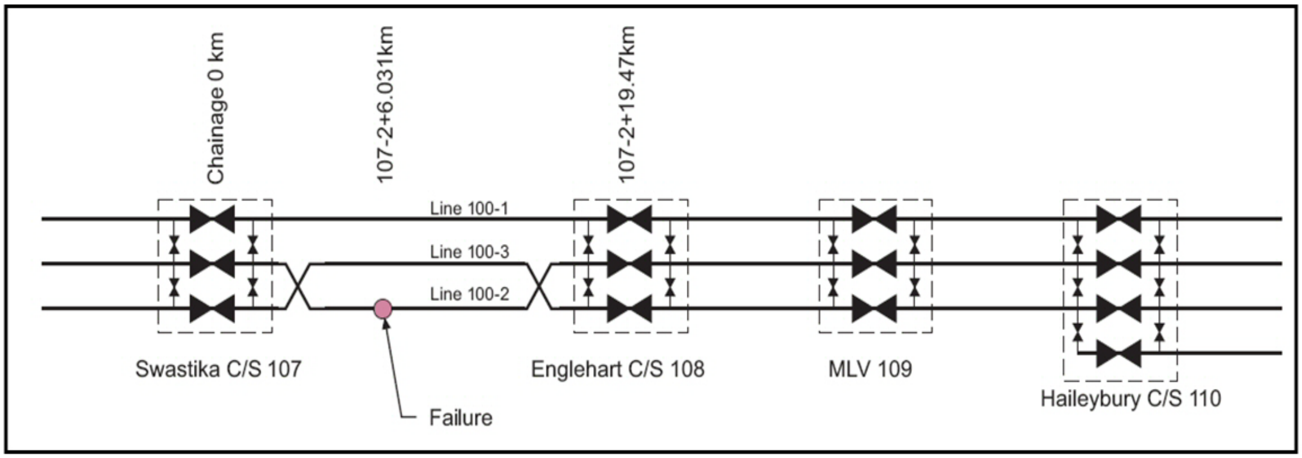

Figure 2 - Schematic of Pipeline Failure relative to Compressor Stations and Valves

At 1213, MLV 108-2 closed automatically due to a Low Pressure Shut-off as confirmed by the SCADA telemetry. With the automatic closure of MLV 108-2, the failed section of pipeline between MLV 107-2 and 108-2, was now fully isolated.

Site Examination

As a result of the rupture, two sections of pipe separated from the pipeline. A severely wrinkled pipe section was ejected during the explosion and was found approximately 150 m from the rupture location. The other section of pipe was found in the ditch to the south of the failed pipeline (see Photo 1).

Photo 1 – Aerial Photo of the Englehart Occurrence Site

When the suspected origin of the pipe failure was inspected in the field, it was found to exhibit a number of crack-like linear indications along the toe weld[2] of the longitudinal seam weld. These indications were found at locations ranging from 4 to 6 m from the upstream girth weld. Some small indications were also detected on the body of the pipe adjacent to the weld.

Inspection of pipe sections more remote from the incident origin also found small indications of longitudinal cracking. A number of these indications were located near the bottom of the pipe in the upstream section of pipe in close proximity to the crack arrest area.

The ruptured sections of pipe were cut in half to facilitate shipping to the Acuren Group Inc. Laboratory in Edmonton (the laboratory) for metallurgical analysis. Short portions of the still in-place pipeline, which contained the upstream and downstream fracture arrests were cut off the ends of the pipe and also sent to the laboratory. Two sections of pipe that had buckled during the failure event were also cut out and sent to the laboratory after indications were found during a field visual examination.

Before starting the repairs, TCPL excavated several joints upstream and downstream of the occurrence site. Once the joints were exposed, it was observed that tenting of the polyethylene exterior tape coating had occurred over the longitudinal seam weld of the pipe. It was also noted that there were areas of exterior coating disbonding at the 3 o'clock and 9 o'clock positions on the pipe surface.

Site Clean-Up and Pipeline Restoration

The total length of pipeline exposed after the explosion was approximately 13 m. The total length of damaged pipe was 48.22 m. To complete the repair, 48.25 m of pre-tested pipe (i.e., hydrostatically tested and conforming to NEB's authorized pressures) was used to replace the damaged portions of Line 100-2. To perform the repairs, the total length of pipe exposed was 122.7 m. Line 100-2, between MLV 107-2 and 108-2, was returned to normal service on 12 December 2009. There were no operational problems encountered on start-up.

Of TCPL's other two parallel pipelines in the vicinity, Line 100-1 was not affected by the blast and was returned to normal service later that day. However, Line 100-3 remained locked-in with no natural gas movements. Approximately 10 m of Line 100-3 had been exposed during the explosion. After TCPL verified the structural integrity of the exposed portion of Line 100-3, it was returned to full service on 26 September 2009.

The failure site was located within the vicinity of a shallow creek (a tributary to Aidie Creek). Reconstruction and final restoration measures for the creek were determined after consulting with the applicable regulatory authorities. The restoration measures were implemented as proposed in TCPL's Environment Mitigation and Management Plan and its Restoration and

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2 For pipelines, longitudinal seam welding is used to weld abutting edges to form a cylinder tube. The toe weld of the longitudinal seam weld is the contact area on the pipe surface where the weld material comes into contact with the pipe body.

Reclamation Plan. The creek was reconstructed with granular material and river stone and the sloped approaches to the creek were straw-mulched and seeded.

TransCanada Pipeline System

With the addition of the Alberta System (previously referred to as Nova Gas Transmission) to federal jurisdiction in April 2009, TCPL became the largest high/low pressure natural gas delivery system in North America.

TCPL's natural gas mainline system extends from British Columbia to Quebec and consists of 118 compressor stations and more than 39,000 km of buried large-diameter pipe. The system, which is comprised of up to eight parallel pipelines at certain locations, is divided into 30-km intervals (approximate) by isolation valves. TCPL receives natural gas from Western Canadian producers through its collection system and then transports and delivers it to locations across Canada. The system has exit export points in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Quebec.

Class of Pipeline

Most of the TCPL Mainline was laid in sparsely-populated regions and is classified as Class 1 as per existing industry standards. In more populated areas and/or where there are other risk factors (e.g., close proximity to schools, hospitals, etc.), heavier wall pipe thicknesses, classified as Class 2, 3 or 4, are installed. A Class 4 location represents an area of heavy urban population.

For Line 100-2, with an outside diameter of 914 millimetres (mm) and a MOP of 6,895 kPa, the pipe wall thickness changes from 9.1 mm for a Class 1 location, to 11.7 mm for a Class 2 location, to 14.1 mm for a Class 3 location, and to 17.6 mm for a Class 4 location. These pipe thicknesses are based on a common pipe grade of 448 megapascals (MPa) (American Petroleum Institute (API) pipe grade X-65). The rupture was in Class 1 pipe laid in 1973.

Recorded Information

A review of the SCADA Trend logs for Compressor Stations 107 and 110 indicated that the pipeline was not experiencing any unusual events in the vicinity of the occurrence prior to the incident.

Laboratory Analysis of Failed Pipe

The laboratory analysis of the failed pipe included visual examination, non-destructive inspection and destructive metallurgical testing. The analysis determined:

- Failure of the section of Line 100-2 pipe, located at MLV 107-2 +6.031 km, was the result of near neutral pH Stress Corrosion Cracking (SCC) that occurred coincident with the toe of the longitudinal weld seam.

- The root cause of this failure was likely due to tenting of the polyethylene exterior tape coating over the longitudinal seam weld of the pipe that allowed the exterior environment including groundwater, dissolved gases, and some bacteria to come in contact with the pipe surface in the vicinity of the weld toe.

- Markings present on the crack surface were correlated with the times of previous hydrostatic tests that had been performed on this section of the pipeline system.

- Crack growth rate was estimated to be in the range of 0.2 to 0.35 mm per year, but exceeded 0.40 mm per year where cracks coalesced.

- The upstream and downstream joints were found to meet the minimum mechanical properties of the specification in place at the time of pipe manufacture, as well as, those of the current specification.

- The rupture joint of pipe met minimum pipeline requirements.

Other Occurrences and Changes to Maintenance Programs

Since 1985, there have been a number of pipeline failures on TCPL's Line 100-2 that led to changes to maintenance programs:

- A pipeline rupture on Line 100-2 in August 1985 was associated with stress corrosion cracking (SCC). In response to this failure, TCPL began planning an intensive field program, referred to as the "Pipeline Maintenance Program" (PMP). This program consisted of hydrostatic testing of susceptible sections of the system and of investigative excavations along the pipeline. The purpose of the PMP was to ensure the continued safe and reliable service of the pipeline system. However, the program was limited to the sections of Line 100-2 between Winnipeg and Toronto and included sections of pipe coated with polyethylene exterior tape coating. Hydrostatic testing and investigative digs remain the key elements of TCPL's PMP.

- Following a pipeline occurrence in Brandon, Manitoba in July 1989, TCPL examined several other sections of its pipeline system through its PMP. The PMP revealed that Line 100-2 through Northern Ontario was particularly susceptible to SCC. TCPL has had no SCC failures on Line 100-1 between MLV 41 and 130, however, the SCC mechanism has been detected on Line 100-1 in Northern Ontario. In addition, Line 100-1 between Toronto and Montreal, which was built in 1958, exhibited SCC with a maximum depth greater than 40 per cent of the wall thickness. Line 100-3 in Northern Ontario, built in 1982, exhibited SCC with a range of crack depths, not limited to 3% of the wall thickness which had been documented on Line 100-3 since the SCC management program began in the mid-1980s.

- Following a number of pipeline failures in the 1990s, investigated by the TSB, TCPL expanded the scope of the PMP to its present Integrity Management Pipeline Process (IMPP) for Line 100-2 (refer to TSB Investigation Reports P95T0005, P91H0041, P91H0117, and P95H0003).

Cathodic Protection of Line 100-2 in the Vicinity of Rupture

During construction of Line 100-2, the exterior pipe surface was covered with a polyethylene exterior coating system. In conjunction with this coating system, the pipeline was further protected from the effects of corrosion with the application of a Cathodic Protection (CP) system. In the vicinity of the rupture, CP potential, which is measured in millivolts (mV) relative to the copper-copper sulphate reference electrode, was provided by two rectifiers:

1. The first and closest upstream rectifier was located at MLV 107-2 + 4.15 km. This rectifier powered one remote and two distributed ground-beds. The nearest ground-bed to the occurrence site was the remote ground-bed and was located at MLV 107-2 + 4.20 km.

2. The second and nearest downstream rectifier was located at MLV 108-2 + 0.70 km. This rectifier powered one remote ground-bed located at 108-2 + 0.613 km, downstream of the occurrence site.

Close Interval Potential Surveys (CIS) were also conducted. These surveys assessed the CP system effectiveness over the entire length of the pipeline by taking readings between the permanent test stations to verify and optimize system operation. At the occurrence site, the most recent CIS occurred in 2006 following ground bed replacements in the downstream valve section. The CIS was conducted on all three pipelines from MLV 107 to 108. The 'Off' potential values from the CIS were in the range of -900 mV to -950 mV. TCPL's CP criteria were established at -850 mV instant OFF, with an associated minimum 100 mV polarization on the pipeline surface. For the points tested, no anomalies were detected.

Hydrostatic Testing of Line 100-2

Between MLV 107 and 108, Line 100-2 was first pressure tested during the commissioning of the pipeline in 1973. Following the pipeline failure in August 1985 on Line 100-2 near Lowther, Ontario, this section of the pipeline has been monitored as part of an SCC Management Hydrostatic Retest Program. It was hydrostatically tested in 1986, 1991, 1994, 1999, and 2004. In 1999, during hydrostatic testing, a pipeline failure occurred and was subsequently repaired. The hydrostatic retest in 2004 was successfully completed without a pipeline failure.

TCPL develops its hydrostatic retest program on an annual basis using the following criteria:

a) past hydrostatic tests and test failures,
b) operating performance of the pipeline,
c) expected crack growth rates and failure frequency,
d) potential failure consequences (i.e., risk analysis),
e) engineering limit state analysis,
f) SCC condition excavation data, and
g) cathodic protection history.

TCPL's hydrostatic retest procedure is conducted as follows:

1. The pipeline is pressurized using water as the medium and involves subjecting the pipe to a high-pressure strength test. Past tests on the pipe section between MLV 107 to 108 were conducted using a strength test to 100% to 110% Specified Minimum Yield Strength (SMYS) and a hold-time of not less than one hour.

2. The high-pressure strength test is immediately followed by a lower-pressure leak test for a minimum of two hours. The leak tests are normally conducted to a maximum stress of 100% SMYS.

Hydrostatic testing is one of a number of methods available to pipeline companies for crack detection. While the process does not exacerbate the expansion of minor cracks, it can contribute to the growth of cracks that are reaching critical dimensions.

In-Line Inspection of Line 100-2

TCPL conducts pipeline inspection utilizing Magnetic Flux-Leakage (MFL) In-Line Inspection (ILI) tools. This type of inspection device is designed to identify internal and external metal loss, such as surface corrosion. Line 100-2 between MLV 107 to 108 was internally inspected for metal loss using MFL tools in 1989. In 2002, an In-Line Inspection was conducted from MLV 105 to MLV 110.

In the vicinity of the occurrence, during the 2002 ILI test, the maximum recorded peak depth of metal loss was 14% penetration. For the same test, within approximately 300 m upstream and downstream of the occurrence site, the depth of the pipe surface corrosion was in the order of 10% penetration. Based on the 2002 inspection results, six excavations were undertaken which resulted in two sleeve repairs for metal loss and four locations where the pipe was recoated.

At the time of the occurrence, TCPL was reviewing the use of a potentially more comprehensive and flexible ILI tool referred to as Electro Magnetic Acoustic Transducer (EMAT). As a recent addition to the field of ILI, the EMAT inspection tool is specifically designed to detect and size axially-oriented cracks, including SCC type cracks, present on pipeline systems. This ILI tool is a non-contact device that generates an ultrasonic pulse in the section of the pipeline being inspected. During the initial evaluation period, the EMAT tool was used to inspect higher priority locations on the pipeline system.

In December 2009, approximately three months after the occurrence, an inspection was performed for Line 100-2 from MLV 99-2 to 105-2 for the first time using the EMAT tool.

Integrity Management Processes for Pipelines

Section 40 of NEB's *Onshore Pipeline Regulations, 1999* (SOR/99-294) specifies (in part) that: federally regulated pipeline companies are required to develop Integrity Management Processes for Pipelines (IMPP) and to initiate corrective action for defects which are known to exist or are found to exceed criteria established by Canadian Standards Association Z662 – Oil and Gas Pipeline Systems (CSA Z662). Pipeline companies are not bound by any particular method, framework or standard when developing their internal management and protection programs, as long as legal requirements and the desired end results (goals) are met.

TCPL's IMPP is the governing document for integrity management of its pipeline facilities. The IMPP is a risk-based pipeline integrity management process (i.e., System-Wide Risk Assessment (SWRA)). The IMPP addresses the safety and service reliability of the pipeline system, as well as, the regulatory requirements and other related standards (e.g., Canadian Standards Association pipeline standards).

Within IMPP, as part of Hazard Identification and Risk Assessment, SWRA information is used to develop the annual pipeline maintenance program. While its IMPP was not fully implemented at the time of the occurrence, TCPL considered its Hazard Identification and Risk Assessment approach equivalent to the industry standard approach specified by the American Society of Mechanical Engineers, titled "Managing System Integrity of Gas Pipelines" (ASME B31.8S (2004)).

TCPL considered the ASME B31.8S standard in the development of its IMPP, however, the standard is non-mandatory. Consequently, due to the goal-oriented regulation of the Canadian pipelines and as a number of aspects of the ASME standard did not correspond to TCPL integrity management experience, the standard was not adopted in its entirety.

Risk Assessment Results for Line 100-2

TCPL's IMPP identified the following time-dependent threats for Line 100-02:

1. External Corrosion.
2. Stress Corrosion Cracking.
3. Geotechnical (Slope Instability).

In addition to these time-dependent hazards, TCPL also identified other general hazards to pipeline facilities, which included third-party mechanical damage, incorrect operations, and equipment failure. These general threats are mitigated through the implementation and conformance to its Operating and Maintenance Practices and Procedures. Mitigation of third-party mechanical damage is achieved through its Integrated Public Awareness program.

External Corrosion for Line 100-2

To mitigate the threat of External Corrosion on Line 100-2, TCPL conducted a number of defect management condition assessments, including an ILI run utilizing MFL. Prior to the occurrence, the most recent ILI for Line 100-2 in the vicinity of the rupture was conducted in 2002. For 2009, no external corrosion excavations had been planned for the section of pipe between MLV 107 to 108.

After the occurrence, a visual examination of the cleaned pipe surface sections was performed. Based on the visual examination, there was no evidence of any significant general or pitting corrosion on the pipe body external surface. It was noted that there was some general corrosion present adjacent to the occurrence edge at the toe of the longitudinal seam weld on the failed pipe. Utilizing a hand-held inspection device, the maximum depth of this corrosion was determined to be 0.56 mm or 6% of the pipe thickness. There was no evidence of internal corrosion observed.

Environmentally Assisted Cracking for Line 100-2

SCC is a type of pipe defect commonly referred to as Environmentally Assisted Cracking (EAC). TCPL's IMPP for Line 100-2 recognized this type of cracking as a threat. TCPL's SCC program which began in the mid-1980s in response to two pipeline failures on Line 100-2 was a component of PMP. TCPL's Monitoring and Mitigation Program for Line 100-2 included inspection excavations for SCC and periodic hydrostatic retests. In particular, valve segment 107-2 to 108-2 was on an active hydrostatic retest program.

Between 1986 and 2003, four SCC investigative excavations were conducted within 2 km of the occurrence site. One of the excavations occurred approximately 200 m upstream of the site. SCC was discovered at three of the four sites. At two sites, the maximum measured crack depth was under 10% through wall. At the third site, located approximately 1.8 km downstream of the occurrence site, the maximum measured crack depth was 28% through wall.

In 1994, a pipe replacement project was completed approximately 200 m upstream. During this replacement, 57 m of pipe was removed and replaced with fusion-bonded epoxy coated pipe. The removed pipe was later inspected for cracking and the maximum measured crack depth was 19% of wall thickness.

After the occurrence, sections of Line 100-2, both upstream and downstream of the rupture, were both visually and non-destructively inspected for signs of SCC. Visually, there were no signs of SCC or any other EAC-type surface defect on the failed pipe or on the exposed sections of the pipeline. However, non-destructive examination identified indications of EAC-type defects. Specifically, the upstream and downstream pipe joints showed indications of small cracks adjacent to the longitudinal seam weld on the upstream pipe. The field report indicated the maximum crack depth to be 1.27 mm or 14% of nominal wall thickness.

External Pipe Coating Protection for Line 100-2

In 1973, when Line 100-2 was constructed, an exterior pipe coating system consisting of a primer and polyethylene tape single outer wrap was applied to the pipe between MLV 107-2 and 108-2.

During the occurrence, the majority of the tape coating on the failed pipe was either destroyed or significantly affected by the heat of the fire. The tape coating that did remain on the pipe sections exhibited minor tenting across the longitudinal longseam and intermittent wrinkling in the pipe body at the three and nine o'clock positions. At other locations on the pipe, the tape coating was relatively well-bonded to the pipe surface.

Geotechnical Issues for Line 100-2

In response to a slope instability concern at the Englehart River crossing (108-2 + 1.4 km), monitoring equipment was installed in August 2009.

Analysis

The Accident

The accident occurred when cracks in the steel in the vicinity of the longitudinal seam weld progressed to the depth that local permanent yielding occurred at normal operating pressures, leading to the rupture and explosion. The relatively uniform growth of SCC in the toe of the longitudinal weld indicates that SCC had been growing for some time.

When line 100-2 was constructed in 1973, the exterior surface of the pipeline was covered with a polyethylene tape coating system. In conjunction with the exterior tape coating system, the pipeline was protected from corrosion using a CP system. In this occurrence, tenting and disbonding of the external polyethylene coating occurred, which restricted and decreased the effectiveness of the cathodic protection system. Polyethylene tape coated pipelines are known to tent over the longitudinal seam weld and disbond at the 3 and 9 o'clock positions on the pipeline surface. The tenting permitted the outside environment to fill the void with groundwater, dissolved gases, and bacteria which came in contact with the pipe surface. Once in the vicinity of the weld toe, the disbonded exterior coating permitted the development of EAC-type cracks, such as SCC. The cracking continued to grow over time assisted by the normal pressure cycles associated with pipeline operations. Although In-Line Inspections were being conducted on a regular basis for this section of pipe, the inspection tool, which was based on magnetic flux leakage, was not designed to identify the stress corrosion cracking in the longitudinal seam weld.

In-Line Inspection Tools

In-Line Inspection tools have been designed to detect pipe defects such as cracks and metal loss due to corrosion. The axially-oriented Magnetic Flux-Leakage (MFL) ILI tool will identify internal and external metal loss, such as surface corrosion. However, this ILI tool has limited ability to identify EAC-type cracks (e.g., SCC), especially when they occur coincident with the toe of the longitudinal weld seam. If there is substantial corrosion associated with the colonies of SCC, the MFL will identify the corrosion, but not necessarily the presence of EAC-type cracks. TCPL does not utilize MFL tools for crack detection.

While In-Line Inspection based on Magnetic Flux Leakage has been successful at identifying corrosion zones, this type of ILI is not suitable for detecting SCC on the exterior surface of the pipe. When In-Line Inspection tools cannot adequately detect EAC-type defects on the exterior surface of the pipe, such as SCC, there is an increased risk that these types of defects will occur and remain undetected, leading to in-service failures.

As a recent addition to the field of ILI, the EMAT inspection tool is specifically designed to potentially detect and size cracks, including SCC. At the time of the occurrence, the EMAT tool was being introduced by TCPL, as part of a controlled implementation approach. Although EMAT has been around for many years, it was utilized only in a limited and manual application to find surface defects. What is new is the successful application of this technology to an ILI-type device. EMAT ILI tool technology may prove to be an effective method for identifying EAC-type crack defects, such as SCC.

Cathodic Protection Program for Line 100-2

Polyethylene coated pipeline systems have been known to tent over the longitudinal seam weld and disbond and wrinkle from the pipe surface which shields the pipe surface from the ability of the CP system to act positively and protect the pipeline system. Once this situation arises, the aggressive exterior environment moves into the space between the pipe surface and the polyethylene coating, leading to the development of EAC-type cracks, such as SCC. As TCPL determined from CP test results for MLV 107-2 to 108-2 and despite the tenting of the polyethylene coating, the tested CP values were found to be in the accepted range of values.

Integrity Management Pipeline Process for Line 100-2

In response to various integrity and safety issues associated with pipeline hazards and threats, TCPL established its Pipeline Maintenance Program. The overall objective of the PMP is to ensure a safe and reliable transportation network for natural gas to consuming markets. Initially limited to Line 100-2 in the pipeline corridor between Winnipeg, Manitoba and Toronto, Ontario, the PMP was expanded to cover all polyethylene coated pipelines in the TCPL system.

To address safety and integrity issues on natural gas pipeline systems, the ASME undertook to establish an industry standard. This work culminated in the development of ASME B31.8S, titled "Managing System Integrity of Gas Pipelines" (2004). With the promulgation of this standard, TCPL proceeded to modify its PMP by adopting selected tables from the ASME B31.8S standard. The original PMP was now transformed into the IMPP with the addition of these selected tables. This was consistent with the goal-oriented approach to pipeline integrity adopted in Canada.

The following TSB Engineering Laboratory report was completed:

LP024/2010 – Review of Pipeline Failure Examination TransCanada Pipeline, Line 100-2.

This report is available from the Transportation Safety Board of Canada upon request.

Findings as to Causes and Contributing Factors

1. The accident occurred when cracks in the steel in the vicinity of the longitudinal seam weld progressed to the depth that local permanent yielding occurred at normal operating pressures, leading to the rupture and explosion.

2. The pipeline surface was exposed to an aggressive exterior environment when minor tenting and disbonding of the external polyethylene coating occurred, which restricted and decreased the effectiveness of the cathodic protection system.

3. Within the void created from the tenting of the polyethylene coating, shielding of the pipeline surface from CP current occurred and stress corrosion cracking developed in the toe of the longitudinal seam weld.

4. Stress corrosion cracking continued to grow over time assisted by the normal pressure cycles associated with pipeline operations.

5. Although In-Line Inspections were being conducted on a regular basis for this section of pipe, the inspection tool, which was based on magnetic flux leakage, was not designed to identify the stress corrosion cracking in the longitudinal seam weld.

Finding as to Risk

1. When In-Line Inspection tools cannot adequately detect Environmentally Assisted Cracking defects on the exterior surface of the pipe, such as Stress Corrosion Cracking, there is an increased risk that these types of defects will occur and remain undetected, leading to in-service failures.

Other Findings

1. While In-Line Inspection based on Magnetic Flux Leakage has been successful at identifying corrosion zones, this type of ILI is not suitable for detecting SCC on the exterior surface of the pipe.

2. Despite the tenting of the polyethylene coating, CP system testing determined that it was within the accepted range of values.

3. EMAT technology may prove to be an effective method for identifying EAC-type crack defects, such as SCC.

Safety Action Taken

1. TCPL reduced the interval for hydrostatic testing by one year, from five to four years, for valve sections on Line 100-2 with previous in-service or hydrostatic test failures.

2. TCPL conducted in-line inspections for SCC using an EMAT-type tool and hydrostatic retests to verify the pipe integrity on three valve sections of Line 100-2.

3. On 18 November 2009, TCPL tested the effectiveness of its CP system by means of a close pipe-to-soil survey utilizing an "Off" Potential survey technique. It was determined that the CP system met its CP criteria. There were no plans to modify and/or upgrade the CP

system in the general area of the occurrence. No rectifier adjustment was made following the PSP reading.

4. TCPL has been and continues to be committed to enhancing its stress corrosion cracking ("SCC") management capabilities through the development and implementation of crack-sensitive in-line inspection ("ILI") tools.

5. The third generation EMAT tool is currently being run on the TCPL system on a controlled implementation basis to validate its crack detection and sizing capabilities. At the time of this writing, TCPL has completed several runs with the EMAT tool including: MLV 49-2 to 53A-2, MLV 95-2 to 99-2, and MLV 99-2 to 105-2. Correlation excavations are also proceeding with the goals of validating tool results in consideration of site susceptibility based on predictive modeling, pipe coatings polyethylene tape and asphalt enamel, and by valve section downstream of compressors. In the event validation is achieved, TCPL has developed a five-year EMAT ILI plan (2009 to 2013) to inspect between MLV 41 (Winnipeg) to MLV 130 (north of Toronto) on Line 100-2.

6. TCPL is also participating with other ILI vendors in the development of additional SCC ILI capabilities.

7. To help companies develop and implement effective management and protection programs, on 08 June 2010, the National Energy Board issued a letter to all its regulated companies, attaching the NEB Management and Protection Program Evaluation and Audit Protocol, which describes the methodology that is to be used in the Board's audit process.

This report concludes the Transportation Safety Board's investigation into this occurrence. Consequently, the Board authorized the release of this report on 29 September 2010.

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