Transportation Safety Board of Canada

Bureau de la sécurité des transports du Canada

# PIPELINE INVESTIGATION REPORT
# P02H0017

## NATURAL GAS PIPELINE RUPTURE

## TRANSCANADA PIPELINES
## LINE 100-3, 914-MILLIMETRE-DIAMETER LINE
## MAIN-LINE VALVE 31-3 + 5.539 KILOMETRES
## NEAR THE VILLAGE OF BROOKDALE, MANITOBA
## 14 APRIL 2002

Canada

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## *Summary*

At approximately 2300 Central daylight time, on 14 April 2002, a rupture occurred on the 914-millimetre-diameter natural gas transmission pipeline, at a zone of near-neutral (low) pH stress corrosion cracking, on Line 100-3 of the TransCanada PipeLines, at main-line valve 31-3 + 5.539 kilometres, approximately two kilometres from the village of Brookdale, Manitoba. Following the rupture, the sweet natural gas ignited. With the automatic closure of main-line valves upstream and downstream of the rupture site, the fire self-extinguished at 0230 on 15 April 2002. There were no injuries. As a precautionary measure, approximately 100 people were evacuated from the occurrence area within a four-kilometre radius, including the village of Brookdale, for a period of one day.

*Ce rapport est également disponible en français.*

# *Other Factual Information*

At approximately 2300 Central daylight time,[1] a rupture occurred on the 914-millimetre (mm) natural gas transmission Line 100-3 (main line) of TransCanada PipeLines (TransCanada) at main-line valve (MLV) 31-3 + 5.539 kilometres (km), approximately 2 km from the village of Brookdale, Manitoba.

Before the rupture, all pipeline operations were normal and being managed out of the TransCanada Calgary Gas Control Centre (CGCC) through the Supervisory Control and Data Acquisition (SCADA) system. At Compressor Station 30, located upstream of the rupture site, natural gas was being discharged in a common configuration with compressor plants D and E on line. All side valves and all tie-over valves at the station were in the open position, allowing natural gas to flow through these valves. At Station 34D, located immediately downstream of the rupture site, natural gas was being discharged into Lines 100-4, 100-5 and 100-6 and was being free-flowed into Lines 100-1, 100-2 and 100-3.

One component of TransCanada's computer-based systems is the Advisory System (AS), which is an expert system developed to complement existing pipeline operations. The AS consists of five detection modules: bottleneck, anomaly, transient, MLV closure, and rapid line break. The AS does not duplicate information available from the SCADA or other tools; rather, it continuously monitors existing data, analyzes for cause, and alerts the CGCC once a reasonable degree of confidence in the significance of an identified event has been established. The AS assigns priorities to an event from insubstantial, through marginal, weak, moderate, substantial, strong to very strong. The CGCC is alerted when a priority exceeds the marginal level. Upon receipt of an AS alert, the CGCC is required to verify the event from other sources before taking action. The system typically identifies some 1300 events per day that do not justify an alert and are dismissed.

At approximately 2303, TransCanada's Line Break Detection Application (LBDA) detected the "First Transient Wave," indicating a possible line break on the pipeline system. At this time, the scale and number of transients being identified and recorded by the AS, at Station 30, were very small. During this time, a pressure drop of approximately minus 60 kilopascals (kPa) within a three-minute time period was recorded by the AS. The AS did not produce at this time an "insubstantial" confidence notification level rating to the CGCC, which would indicate to the CGCC that an initial line break pattern had been identified. Within seconds of the identification of this transient line break pattern and without notifying the CGCC, the AS automatically increased the frequency at which it re-evaluates the current pipeline situation surrounding the First Transient Wave indication. However, in spite of the transient wave being identified, the scale and number of transients did not meet the pre-established criteria to justify the AS notifying CGCC operators of a possible line break, since there was no supporting evidence of transients downstream at Station 34.

At approximately 2304, the AS identified indications of a transient wave at Station 34, which supported the line break argument. The AS raised the confidence rating to "marginal." However, this was still considered by the program to be insufficient evidence to support alarming, flagging or engaging the CGCC operators of a possible line break. At this time, the

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[1] All times are Central daylight time (Coordinated Universal Time [UTC] minus five hours) unless otherwise stated.

pressure transient waves were negative (that is, decreasing), but not to the point where they were outside the range of normal operating rates of decrease at Station 30. Because certain compressor units were attempting to maintain discharge pressure at the station, the increase in power consumption at the stations was a reasonable explanation for the increase in flow, and an argument against the possibility of a line break. This analysis was being performed by the AS independent of the CGCC operators.

At approximately 2309 and six minutes after the AS identification of the "First Transient Wave" at Station 30, the first notification was issued to the CGCC by the AS. The CGCC received an AS "weak" confidence level rating notification of a line break. The initial notification indicated that there was a pressure transient wave of minus 109 kPa on Line 100-3 at Station 30, and a pressure transient wave of minus 300 kPa on Line 100-3 at Station 34. While not programmed to flag the control room operator regarding any unexplained changes in the monitored flow rate changes, the AS also indicated a plus 54 million cubic metres per day or 27 per cent increase in natural gas flow rates at Station 30, indicating that the station compressor was attempting to maintain discharge pressure while at the same time encountering less friction resistance from Line 100-3. The number and size of the decreasing pressure transients at the two stations were greater than could be explained by the flow and power increase, and yet the AS issued a "weak" notification.

At approximately 2310, the first verbal report from a member of the public indicated that there was an explosion and fire on TransCanada's system near Brookdale, approximately 1.2 km from Rural Road 464. At the same time, TransCanada's SCADA system gave very strong visual and graphical evidence to the CGCC of a possible line break between Stations 30 and 34. From this time on, several calls from the public and emergency services organizations were received by the CGCC related to the explosion and fire.

At approximately 2311, the CGCC received an AS "moderate" confidence level rating notification of a line break, followed by a "substantial" confidence rating at 2314. Between 2316 and 2317, the CGCC initiated a series of SCADA system commands to close and/or isolate all MLVs and tie-over valves at Stations 30 and 34 for Lines 100-1, 100-2, 100-3, and 100-4. Closure of the valves was confirmed through the SCADA system by 2318. TransCanada employees were dispatched to each of the valve sites to verify and confirm closure of each valve.

At approximately 2317, the CGCC received an AS "strong" confidence level rating. The notification indicated that there was a transient of minus 732 kPa at Station 30, and that there was a transient of minus 527 kPa at Station 34. The AS indicated an unchanged plus 54 million cubic metres per day or 27 per cent increase in natural gas flow rates at Station 30.

At approximately 2318, TransCanada advised the Royal Canadian Mounted Police (RCMP) of a possible line break near Brookdale and that TransCanada personnel had been dispatched to the rupture site. The RCMP advised TransCanada that it would be implementing a 4 km radius evacuation area around the rupture site and would be evacuating local residents within this perimeter.

At approximately 2321, the AS produced a "very strong" confidence rating based upon a transient of minus 1652 kPa at Station 30, a transient of minus 879 kPa at Station 34, and a decrease in natural gas flow rates at Station 30.

At approximately 2322, the CGCC initiated a series of SCADA-based commands that effectively closed all upstream suction valves at Station 30, and immediately noticed that the pressure on Line 100-3 was dropping, indicative that the line break had occurred on Line 100-3.

At approximately 2326, except for a couple of tie-over valves associated with Lines 100-6 and 100-7, all open tie-over valves at MLV 31, located approximately 5.539 km upstream of the occurrence site, were issued close commands, which performed as requested through the SCADA system. Complete closure was confirmed through visual verification by TransCanada employees.

At 2333, CGCC re-issued a stop command to Compressor Unit 30D located at Station 30, which had previously failed to stop when commanded to by the CGCC at 2317. Unit 30D then shut down successfully.

At approximately 0130, on 15 April 2002, the isolation of the main line was completed with the closure of upstream and downstream main block valves as well as all tie-over valves connecting the failed line to adjacent lines, which effectively stopped the flow of additional natural gas into the isolated break site. At this time, the pressure in the break section of main line was reduced to atmospheric pressure.

At approximately 0230, the major fire self-extinguished at the break site due to actions undertaken at 0130. The isolation of the break site was accomplished with the automatic closure of four MLVs and various tie-over valves with adjacent lines, by low-pressure shut-off devices and the remote closure of 22 valves by the CGCC through the SCADA system. As a precaution, the operating pressures for Lines 100-2 and 100-4 were temporarily reduced to 1000 kPa, until the integrity of these two adjacent main lines could be confirmed. At the time of the break, the estimated pressure at the rupture site was 6010 kPa. The total volume of natural gas consumed by the fire and lost to atmosphere was estimated at 6 812 600 cubic metres.

There were no injuries, fatalities or damage to any third-party homes, buildings or facilities as a result of the rupture and fire. Approximately 100 people within a 4 km radius were evacuated by the RCMP. An evacuation centre was set up in Carberry, Manitoba. The evacuation area included 30 families, 3 businesses and 1 public high school. At 1500, on 15 April 2002, evacuees were allowed to return to their residences. On 25 April 2002, the repairs by TransCanada of the damaged pipeline were completed. Line 100-3 was fully restored to normal service on 05 July 2002.

The TSB Engineering Laboratory (report LP 025/2002) determined that the pipeline ruptured due to overstress extension of pre-existing cracks. The cracks had initiated on the outside surface of the pipe and progressed in a mode of failure identified as near-neutral (low) pH stress corrosion cracking (SCC). This type of SCC has also been referred to as transgranular SCC, meaning that the crack progressed through the grain structure as opposed to a crack progression between the grain boundaries.

Since the operating pressure exceeded the failure pressure of the initiating series of cracks, the cracks began to extend axially and through the remaining ligaments by ductile tearing. Rupture of the pipe occurred in a fully ductile manner. Although pitting corrosion was present in the failure initiation area, it was superficial and had not significantly reduced the wall thickness of the pipe. However, the corrosion pits did provide potential stress concentrator sites where cracks could have initiated. The presence of minor corrosion pits is indicative that the cathodic protection (CP) was locally ineffective for some time during the operation of the pipeline, a condition also required for the development of SCC. The metallurgical analysis did not identify any evidence of pre-existing mechanical damage in the area of the failure initiation.

The original pipe used in the construction of valve section MLVs 31 to 32 was produced by Stelco in 1970. The double-submerged arc-welded (DSAW) straight seam pipe was manufactured in accordance with the requirements of the American Petroleum Institute (API) 5L Grade X65. The section of pipe containing the initiation had a nominal outside diameter of 914.4 mm, a nominal wall thickness of 8.08 mm and a specified minimum yield strength (SMYS) of 448 megapascals (MPa). The mechanical properties of the pipe material were tested and found to be consistent with code requirement for this pipe. Additional colonies of SCC were observed on the pipe segments recovered from the site, but their size was considered to be small, and all segments of these pipe would have passed a hydrostatic test to 125 per cent of the maximum allowable operating pressure (MAOP).

The exterior coating system on Line 100-3 was an "over-the-ditch" hot-applied asphalt enamel coating (meaning hot-poured over the pipeline) with a spiral outer wrap. The coating brand was Lion 5A60 asphalt enamel and the outer wrap was asphalt-impregnated No. 15 asbestos felt. The outer wrap consisted of 10 to 20 per cent serpentine (chrysotile) asbestos fibre with 5 to 15 per cent glass fibre and 65 to 85 per cent non-fibrous filler.

The thickness of the hot-applied asphalt enamel coating was found to average 2 mm to 3 mm on the top of the pipe and 7 mm to 10 mm on the bottom of the pipe. In some areas along the bottom of the pipe, the thickness of the coating was as high as 20 mm, indicating that the hot asphalt had run down the pipe during its original application. Under concrete weights used for buoyancy control purposes, an additional asphalt layer had been applied. Some isolated areas of the coating along the top surface of the pipe revealed a bubbled coating and, in one area, the coating would crumble very easily.

Wrinkling of the exterior coating was observed on some areas of the pipe. However, overall, the exterior asphalt coating appeared to adhere well to the pipe. Impedance testing determined that the CP resistance to corrosion ranged between intermediate to good and that the coating was not shielding the pipe from the CP. Where the coating was intact, the corrosion rate was found to be within the low corrosion range, meaning light surface corrosion. During coating removal, evidence of disbondment or a lack of a tight bond was observed on the bottom section of the downstream end of one of the joints of pipe.

As a result of the rupture of Line 100-3, approximately 93 metres (m) of main-line pipe was directly affected. After the rupture, eight pipe fragments, which accounted for the entire affected length of pipe, were found within a 264 m radius of the rupture site. At the rupture site, where 7.2 m separated Lines 100-3 and 100-4, two swamp weights on Line 100-4 were partially exposed as a result of the occurrence.

The eight pipe fragments from the occurrence site were re-assembled at the TransCanada service centre in Airdrie, Alberta, with the fragments pointing in the correct orientation of the flow of natural gas. It was determined that the failure had occurred at the 5:15 position on the pipe. The eight pipe fragments and the additional upstream and downstream joints of pipe were water-blasted and the outside pipe surface was inspected using magnetic particle inspection (MPI). The 118 m of pipe examined revealed a total of 159 colonies of axially aligned cracks, typical of near-neutral (low) pH SCC. The colonies were uniformly distributed over the pipe length;

however, a greater number of colonies were observed within 15 m of the break initiation site. These colonies of SCC tended to be either along the bottom of the pipe or uniformly located around the circumference of the pipe.

Once all pieces of pipe were assembled, the occurrence initiation site was identified to be located in one of the first colonies near the bottom of the pipe. Most of the other colonies consisted of 10 to 20 small cracks and averaged 40 mm in length, although seven colonies were longer than 100 mm. Individual cracks were short, averaging 5 mm in length and nine cracks were longer than 10 mm. There have been very few cases of near-neutral (low) pH SCC in asphalt enamel-coated pipelines.

The CP system for the main line was installed in 1970 as the pipeline was constructed. CP potential levels are verified with annual pipe-to-soil surveys consisting of recording potentials at test leads attached to the operating pipeline, approximately 1.6 km apart. The nearest CP groundbeds are located upstream at MLV 30 + 24.90 km and downstream at MLV 32 + 11.72 km, which were originally installed in 1959. A third influencing remote groundbed at MLV 30 + 21.75 km was installed in 1986. In the vicinity of the break site (located at 5.539 km), the nearest test leads are located at MLV 31 + 5.17 km and MLV 31 + 6.76 km. An analysis of the CP potentials records for that area illustrated that TransCanada met its own "ON" potential criterion of minus 900 millivolts (mV) consistently. The review of TransCanada's historical CP data showed that the polarization shift of 100 mV has been maintained with a 95 per cent statistical confidence level. These results meet the specifications of the National Association of Corrosion Engineers Standard RP0169-96, Item No. 21001, Section 6.2.2, for steel and cast iron piping.

The failure initiation area was found to be coincident with the junction of two physiographic landforms, which likely were subject to a fluctuating ground water table. Although the CP potential levels at this location were found to be within the TransCanada criteria, and the coating was determined not to shield CP potential levels, the environmental fluctuations found at this transitional location could have led to variations in CP potential levels. The results of the soil and water samples taken indicated that anaerobic conditions required for near-neutral pH SCC had been present at the failure location for some time.

The SCADA records indicate that, at the time of failure, Line 100-3 had been operating at a steady state of pressure of approximately 6060 kPa, which corresponds to 75.9 per cent of SMYS. The MAOP of Line 100-3 was 6065 kPa, representing 76.6 per cent of SMYS. Based on the discharge pressure at Station 30, the pressure at the rupture site was calculated to have been 5880 kPa. The temperature of the buried pipe / flowing gas was determined to be 12°C to 15°C at the time of rupture.

Based upon corporate-wide policy decisions related to the TransCanada ongoing Integrity Management Program (IMP), the section of Line 100-3 between MLV 25 and MLV 41 had been internally inspected for metal loss conditions associated with corrosion in 1998, using a magnetic flux leakage (MFL) in-line inspection (ILI) tool. TransCanada's policy dictates that, following each ILI using an MFL, all major anomalies and a sample of minor anomalies are to be inspected and either re-coated, repaired or replaced. In the vicinity of the rupture location, the 1998 ILI did not identify any features that required repair. It should be noted that MFL tools are not designed to identify zones of cracking, such as SCC. This type of MFL tool is designed to only identify surface anomalies, such as metal loss and corrosion on the outside and on the inside of the pipe.

On 07 April 1989, a leak occurred on Line 100-3 at MLV 31 + 8.8 km. A metallurgical investigation into the leak attributed the cause of the leak to SCC in the pipe body beneath a hand-applied exterior coating repair. In 1990, TransCanada performed a hydrostatic retest of this valve section. The minimum test pressure recorded during the one-hour strength test was 8647 kPa (109.5 per cent of SMYS), followed by a 24-hour leak test at a minimum test pressure of 7166.4 kPa (90.5 per cent of SMYS). There were no test failures, indicating that there was an absence of critical size cracks, and Line 100-3 was returned to normal service.

On 05 April 2002, a leak survey was conducted by helicopter over the right-of-way (ROW) with a leak detection apparatus between MLV 31 and MLV 32. A review of the TransCanada Leak Survey Inspection Record indicated that no leaks had been identified. On the same day, a helicopter aerial patrol was also conducted at the same time over the ROW, with nothing noted by the pilot, and no concerns were reported.

## *Analysis*

The identification of near-neutral (low) pH SCC in asphalt enamel-coated pipelines is not a new phenomenon. However, the progression to failure of the near-neutral (low) pH SCC, in association with an asphalt-coated pipeline, occurs very infrequently. A review of work undertaken in the 1990s showed that the vast majority of SCC failures were attributed to pipelines with a polyethylene tape exterior coating. While there has been a limited number of pipeline failures attributed to near-neutral (low) pH SCC on asphalt-coated pipelines, in the majority of cases, there have been attributes, such as dents, scratches, and concrete weights, associated with this type of failure. A more comprehensive industry assessment of SCC data relating to coating types found that the frequency of all SCC under asphalt and coal tar was approximately 10 times less than the occurrence of SCC under polyethylene tape. This study also found that there were similar attributes associated with near-neutral (low) pH SCC on asphalt-coated pipelines.

The pattern of SCC distribution on the rupture pipe fragments may be indicative of an environmental transition zone at the occurrence site. Variations in a number of environmental factors, such as water table level, drainage patterns, oxygen content, soil texture and soil conductivity, were found to exist at the occurrence site. The variation in any of these factors may produce conditions that encourage the development of near-neutral (low) pH SCC under the asphalt coating, which will then assist in the growth of these cracks. Large disparities in size and severity were noted between the SCC initiating the failure and the other SCC found on the failed segments of pipe. However, the absence of the exterior coating, which was completely burned off during the fire, precludes any definitive understanding of the mechanisms present at the failure location. Since the failure initiated at the bottom of the pipe, it is possible that the exterior coating was damaged by outside forces, such as pipe movement. Such a situation would explain the differential size and severity differences in the SCC on the pipe segments.

Several simultaneous conditions are precursors and necessary for SCC to initiate on the pipe surface and grow to failure. In addition to susceptible material and access of the exterior environment to the pipe surface under the disbonded coating, near-neutral (low) pH SCC favours anaerobic soil conditions, together with ground water containing carbon dioxide. CP is generally considered to be beneficial in mitigating the development of the near-neutral (low) pH form of SCC. However, extensive research has found that the development of SCC requires shielding of the CP system by the exterior coating (coating disbondment), the absence of an effective CP system, or a CP system where there are variable CP levels over time.

Although the line was protected with an asphalt exterior coating, the exterior coating can degrade over time to the point that water and moisture can migrate through the coating, enabling CP potential through the asphalt coating. If the CP levels are insufficient, the underlying steel will begin to corrode. The presence of the shallow external corrosion indicates that there were periods of time during the operating history of the pipe when the steel beneath the coating was exposed to electrolytes and insufficient CP. This sustained the corrosion process, and the CP levels at the pipe were insufficient to prevent further corrosion. Insufficient CP levels may have occurred from time to time as a result of factors related to the pipeline, with decreasing CP system efficiencies or with varying resistivities of local soil conditions.

The soil analysis at the occurrence site found that the location had a seasonally variable water table that would contribute to both the anaerobic conditions and the variable level of CP potential in the general area of the occurrence. Since the occurrence area was found to be in a transitional environment zone, the overall conditions were more variable with respect to CP potential levels, soil moisture, and soil carbon dioxide. Under these conditions, SCC was able to develop on the pipe surface under the coating and grow to failure. Variations in the thickness and quality of the exterior coating may have encouraged a greater development of SCC in one location versus another location. That is, the less the quality and thickness of the exterior coating, the higher the probability of SCC developing on the exterior pipe surface. In 1989, in the immediate vicinity of the present occurrence, TransCanada had a SCC-related pipeline occurrence on Line 100-3.

As part of the company's ongoing pipeline IMP, TransCanada performed an ILI of Line 100-3 in 1998 between MLV 25 and MLV 41. The ILI work was carried out using an MFL inspection tool. As part of the IMP work, TransCanada inspected all major anomalies and a sample of minor anomalies identified by the MFL tool to either re-coat or repair any damaged pipe identified by the tool.

While an MFL tool can identify areas on the pipeline containing dents with associated cracking or gouging with associated cracking, because the associated cracking is large in both these cases, the MFL-type tool was not designed to identify the smaller zones of cracking, such as SCC, which were found on the pipe surface at the occurrence site. Furthermore, MFL-type tools are not capable of detecting axial-oriented cracks. It should be noted that some MFL tool indications are found to be dents or other types of features, even though the tool was not designed to detect these features. Before the present occurrence, TransCanada had found evidence of SCC-type mechanisms in the general area of the present occurrence, which had resulted in a pipeline leak. Following that occurrence, if TransCanada had inspected Line 100-3 with the new generation of high-resolution tools commercially available since 1999 and specifically designed to detect cracks in the wall of pipeline steel (ILI crack detection tool), the zones of cracking on the exterior surface of the pipeline at the present occurrence site could have been identified and, if so identified by this advanced crack detection tool, would have been repaired. Such was not the case.

At many other locations on its system, TransCanada has successfully used commercially available, new-generation, high-resolution ILI crack detection tools as part of the company's ongoing programs related to pipeline integrity. While the availability of an effective detection tool for use in routine, proactive pipeline integrity programs on operating gas pipelines is limited, high-resolution ILI crack detection tools do exist for the length and depth of SCC found at the occurrence site. Therefore, TransCanada corporate policies related to integrity management as dictated by its IMP and any other associated corporate policies on the use of ILI crack detection devices on the pipeline system may require review and revision.

Theoretically, when a rupture occurs on an operating pipeline system, the sudden and rapid rate of change in the internal, operating pressure levels of the pipeline provides a clear and readily identifiable indicator of the events transpiring. The TransCanada AS's LBDA is based upon detection of this sudden and rapid rate of change in operating pressures. As with every rupture of a pipeline system, there is a time delay associated with the identification of the pipeline rupture and its exact location, principally due to the length and complexity of the pipeline between operating stations. In a large number of cases, the public is the first to notify the pipeline control centre that a rupture has taken place, especially if an explosion and fire is associated with the pipeline rupture.

In order to identify that a rupture has taken place, there must be a depressurization of the pipeline over the length of pipeline between the upstream and downstream stations. Once depressurization begins, the automatic record of internal pressure at each station begins to register a decline in internal operating pressures. During the critical period following a pipeline rupture, the time delay in receiving the depressurization signal becomes a vital factor for the CGCC when making key decisions associated with shutting down the pipeline, re-routing natural gas flow supplies that normally move in the pipeline system, and beginning the process of initiating an emergency response.

Within the first 10 minutes after the rupture of Line 100-3, it should have become obvious to the CGCC that events were occurring on the pipeline system that could not be described as standard pipeline operating conditions with a 27 per cent increase in flow rate out of Station 30 and an associated power increase. However, at this point, it would not have been completely clear to the CGCC personnel exactly what was taking place and where exactly the problem was on the system between Stations 30 and 34. This situation was especially noticeable at Station 30 because of the rapid increase in the gas flow rates when combined with a drop in discharge pressure and an automatic increase in power. However, at Station 34, the delays in recording a drop in suction pressure were masked by the distance from the rupture site to this station.

Working independently of and based on background information provided by the TransCanada SCADA system, the LBDA, which forms part of the AS, was recording and processing SCADA data to identify known event patterns, which could have been flagged and alarmed to the CGCC, if the AS had been designed to do so. Within minutes of the pipeline rupture, the AS identified the "First Transient Wave" of unknown origin, which was indicative that an initial line break pattern had been identified by this monitoring and analysis software. Within another few seconds, the AS began to record and initiated software monitoring actions associated with the identification of the "First Transient Wave" to determine if a rupture of the pipeline had taken place. However, this key operational information was not passed to the CGCC by the AS because the confidence notification level rating calculated by the AS was too low. While the AS was automatically increasing the frequency at which it re-evaluates the current pipeline pressure levels related to the "First Transient Wave" indication, the CGCC did not have any indication of the actions of the AS and the potentially serious event being monitored by the automated systems. The CGCC was advised of the emergency condition six minutes after the initial identification by the AS that Line 100-3 had ruptured and that the AS had recorded, processed and concluded that there was "weak" level evidence of a line break on Line 100-3.

Within the CGCC, overall management and control of activities within the control centre rests with the most senior person (Senior Manager or Senior Controller) on duty at the time. Since the CGCC covers the complete pipeline system, the Senior Controller has complete access to and final accountability of the CGCC actions affecting all pipeline activities. Since the TransCanada system is extensive and very complex, the CGCC is structured to permit optimum management of the pipeline system. Each individual controller has a specific section of the system to control and manage. All decisions, actions, and activities within the designated section of responsibility are controlled by the person managing the pipeline control console. In this occurrence, while the Senior Controller could dial in and view the actions of an individual controller, the accountability for the controllers' actions resided with the Senior Controller.

While these events were transpiring on the pipeline system and the AS was increasing the frequency of monitoring signals related to pressure levels to confirm that a line break had occurred, the Senior Controller of the CGCC was aware of all the activities on the pipeline system except those actions being taken by the AS. Had the Senior Controller been able to observe or to have been notified earlier of any situations being monitored by the AS on a separate computer screen in his/her work area, the investigation and initiation of emergency steps by the Senior Controller could have been initiated sooner. The CGCC received an AS-initiated "weak" notification nine minutes after the rupture, and a notification from the public one minute later. Seventeen minutes after the rupture, the AS had issued a "strong" notification of a line rupture. However, the initiation of the shut-down and containment of the pipeline system was not commenced until 16 minutes after the rupture. The emergency response to this rupture could therefore have been initiated approximately eight minutes sooner had the initial actions of the AS been observed by the Senior Controller.

While the AS was monitoring pressure levels for the "First Transient Wave," the overall responsiveness of the AS could be enhanced if the software were designed to flag the CGCC regarding changes in monitored flow rate and not just the rate of change of internal pressure levels. It is noted that, within the first few minutes after the start of events on Line 100-3, the AS recorded a 27 per cent increase in the flow rate at Station 30, but the AS was not designed to specifically flag the control room operator regarding large changes in these measured flows. The increase in flow rate occurred at the time of the rupture because of a natural hydraulic effect. Since the compressor units at the station had less friction to overcome due to the shorter length of pipeline from Station 30 to the rupture site, the same motive-power could push more natural gas.

## *Findings as to Causes and Contributing Factors*

1. The combination of a disbonded exterior coating, fluctuations in the environmental conditions surrounding the pipe, the presence of anaerobic bacteria, a susceptible high-strength steel pipe, and the existence of atomic hydrogen, probably from the cathodic protection reaction, together with a sustained tensile stress due to the internal operating pressure of the pipeline, permitted a zone of near-neutral stress corrosion cracking to initiate and grow to failure.

2. Corrosion pitting, which occurred during periods of insufficient cathodic protection, was coincident with two physiographic landforms and a fluctuating water table, and may have facilitated the initiation and growth of the cracks.

3. The pipeline ruptured as a result of the extension in an overstress mode within this pre-cracked region.

## *Finding as to Risk*

1. The policies laid out in the TransCanada pipeline Integrity Management Program are risk-based. In spite of the history of stress corrosion cracking in this section of the pipeline, TransCanada did not assess the risk as justifying the use of an in-line inspection crack detection device; therefore, the criteria used may require review and revision.

## *Other Findings*

1. Although TransCanada's Advisory System was configured to monitor and evaluate the potential of a rupture based on various parameters, the trigger for flagging or alarming the Calgary Gas Control Centre was not reached until several minutes after the rupture.

2. Neither the Senior Manager nor the Senior Controller in the Calgary Gas Control Centre had access to the evaluation process being followed by the Advisory System. An alerting and monitoring function could have permitted the emergency shut-down of the pipeline at an earlier stage.

3. By design, the magnetic flux leakage tools used in TransCanada's in-line inspection program for Line 100-3 could detect metal loss but not zones of exterior cracking.

4. Some of the latest generation of in-line inspection tools, available since 1999, can detect and assess zones of stress corrosion cracking. Had they been used, TransCanada may have been able to identify cracks in the pipeline between Stations 30 and 34.

## *Safety Action Taken*

Subsequent to this rupture, TransCanada took the following actions:

- TransCanada verified the integrity of the pipeline section between main-line valve (MLV) 30 and MLV 32 through a hydrostatic retesting program.

- TransCanada performed a complete integrity assessment through visual inspections and assessments of the adjacent sections of Lines 100-2 and 100-4, in proximity to Line 100-3, which were exposed to the erosion and thermal effects resulting from the explosion and fire. In addition to the pipe inspections of these two lines following the rupture, the company exposed 100 m of both lines in July and August 2002, adjacent to the rupture site, to inspect for stress corrosion cracking (SCC). Only a single SCC colony was detected on Line 100-2 and no SCC was detected on Line 100-4.

- Ahead of the planned hydrostatic retests that were conducted on Line 100-3, between MLV 30 and MLV 32, a series of inspections and repairs were performed at locations of known corrosion features on the pipe section having been identified during the 1998 metal loss in-line inspection (ILI) tool run. Once TransCanada completed the investigative dig program, 29 individual joints of pipe were exposed and visually inspected during 15 investigative digs on Line 100-3, between MLV 30 and MLV 32, to verify any corrosion growth of metal loss indications detected during the 1998 ILI work completed, using a magnetic flux leakage (MFL) inspection tool. The investigative dig program resulted in four permanent repairs of Line 100-3 between MLV 30 and MLV 32. These corrosion repairs were required to prevent unnecessary pipeline failures at these identified corrosion features due to their exposure to retesting pressures significantly above normal operation and up to 143 per cent of the normal maximum allowable operating pressure (MAOP). During these excavations, the opportunity was also taken to inspect the pipeline for SCC. Of the 327 m of pipe inspected for SCC, only one minor SCC colony was detected and subsequently ground out. All the inspected pipe was subsequently cleaned and re-coated using a field-applied epoxy coating. It is TransCanada's practice, prior to welding, to inspect locations where new pipe is welded to existing pipelines (tie-ins). In preparation for the hydrostatic retests on Line 100-3, six such welds were necessary to temporarily install the hydrostatic testing fixtures on the pipeline. Crack inspections were, therefore, conducted at each of these six locations on Line 100-3. At five of these weld locations, inspections revealed no cracking on the existing pipe. At one site, located at MLV 31 + 29.8 km, a number of SCC colonies were encountered. At one of these locations, a toe crack was assessed to be of reportable size, according to the Canadian Energy Pipeline Association definition, though very sub-critical. To expedite retesting, a 5 m length of pipe containing the cracks was cut out before making the tie-in weld.

- TransCanada conducted condition excavation monitoring and data gathering activities on Line 100-3 between MLV 30 and MLV 32 to define the likely conditions that were precursors to crack initiation and growth.

- Along Line 100-3, TransCanada has undertaken detailed stratigraphic work to outline soil and water structures to assist in developing a 3-D map of soil horizons and the associated water table.

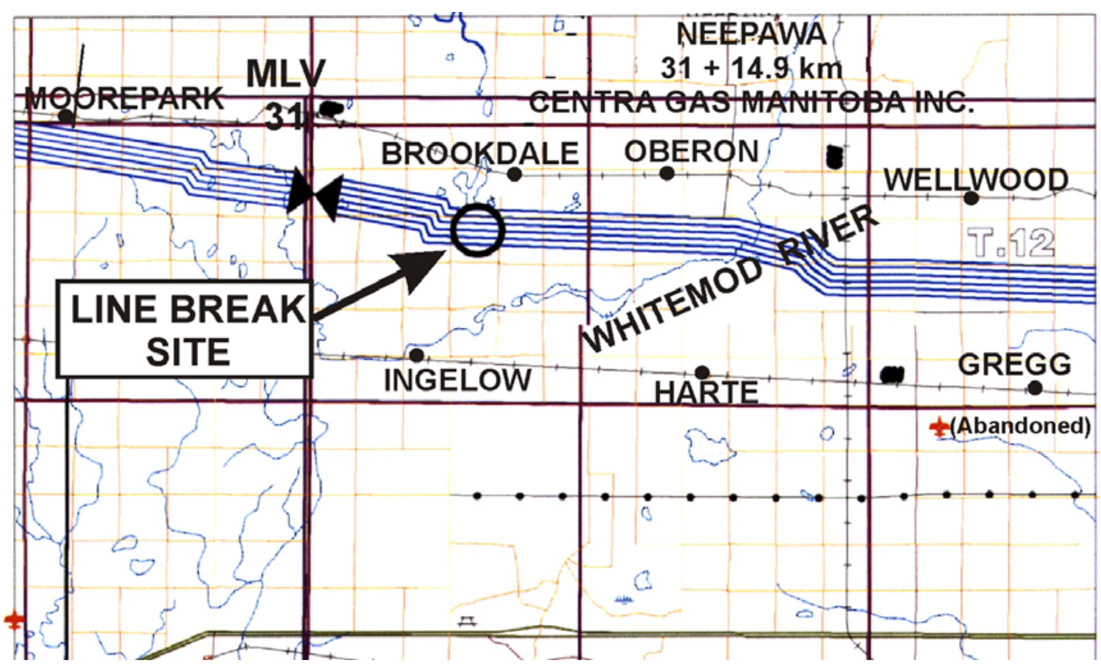
- TransCanada completed data and probe surveys along Line 100-3 to obtain more information regarding cathodic protection performance and the presence and/or existence of aerobic conditions.

- According to TransCanada's Integrity Management Program (IMP), following each ILI using an MFL tool, TransCanada will repair all metal loss features that fail the company's defect acceptance criteria (predicted failure pressure is less that 125 per cent of the MAOP or has a maximum depth equal to or greater than 80 per cent of the nominal wall thickness). TransCanada also conducts risk-based repairs of features at locations where the company corporate risk acceptance criteria are exceeded. TransCanada may also perform verification excavations to assess ILI tool performance.

- According to TransCanada, during October and November 2002, two excavations on 77 m of pipe were conducted on Line 100-3 to inspect for SCC at locations of environmental transitions between MLV 30 + 2.242 km and MLV 31 + 5.310 km. Only a single, minor SCC colony was present and was removed by grinding.

- Following the Brookdale failure, TransCanada initiated two programs to address the issue of SCC associated with asphalt-coated pipeline and fall into two categories: hydrostatic retesting and condition monitoring inspection excavations. In keeping with its IMP, the company undertook a review of its SCC susceptibility models based on the pipeline performance feedback, which resulted in modifications to the company's Hazard Susceptibility Model. Where data were lacking, the company employed conservative assumptions and estimates. Notwithstanding a high level of conservatism and uncertainty in the failure frequency estimates, a risk assessment was made of the asphalt-coated sections of the pipeline system. As a result, a number of pipeline sections were identified for hydrostatic retesting. One of these sections was a 23.3 km section of pipeline on Line 100-3 between MLV 13 and MLV 14, which was successful by retesting and passed without incident. As well, a series of condition-monitoring inspections are underway on various asphalt-coated pipeline sections to reduce the uncertainty in the asphalt SCC susceptibility model. These sites had been selected based upon local soil transitions, several of which reflect variations of the types of soil transitions noted at the rupture site. All performance data, including the results from hydrostatic retests and inspection excavations, will be reviewed by TransCanada to enable continuous improvements in the risk assessment capabilities.

- Since TransCanada has determined a need for an effective, high-resolution ILI crack detection tool specifically designed for use in routine, proactive integrity management programs on natural gas pipelines, it is actively participating in the development of a gas-compatible ILI crack detection technology for use eventually as part of the company's Stress Corrosion Cracking Management Program.



*This report concludes the Transportation Safety Board's investigation into this occurrence. Consequently, the Board authorized the release of this report on 22 April 2004.*

# *Appendix A – Glossary*

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| API | American Petroleum Institute |
| AS | Advisory System |
| C | Celsius |
| CGCC | Calgary Gas Control Centre |
| CP | cathodic protection |
| DSAW | double-submerged arc-welded |
| ILI | in-line inspection |
| IMP | Integrity Management Program |
| km | kilometre |
| kPa | kilopascal |
| LBDA | Line Break Detection Application |
| m | metre |
| MAOP | maximum allowable operating pressure |
| MFL | magnetic flux leakage |
| MLV | main-line valve |
| mm | millimetre |
| MPa | megapascal |
| MPI | magnetic particle inspection |
| mV | millivolt |
| RCMP | Royal Canadian Mounted Police |
| ROW | right-of-way |
| SCADA | Supervisory Control and Data Acquisition |
| SCC | stress corrosion cracking |
| SMYS | specified minimum yield strength |
| TransCanada | TransCanada PipeLines |
| TSB | Transportation Safety Board of Canada |
| ° | degree |