

PIPELINE INVESTIGATION REPORT

P99H0021

CRUDE OIL PIPELINE RUPTURE

ENBRIDGE PIPELINES INC.

864-MILLIMETRE-DIAMETER MAINLINE

KILOMETRE 714.8541

APPROXIMATELY 10.6 KILOMETRES

EAST OF REGINA, SASKATCHEWAN

20 MAY 1999

The Transportation Safety Board of Canada (TSB) investigated this occurrence for the purpose of advancing transportation safety. It is not the function of the Board to assign fault or determine civil or criminal liability.

Pipeline Investigation Report

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864-Millimetre-Diameter Mainline
Kilometre 714.8541
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Summary

At 2059 mountain standard time (MST) on 20 May 1999, Line 3 on the Enbridge Pipelines Inc. (Enbridge) pipeline system ruptured, releasing 3 123 cubic metres (m³) (20,600 barrels) of Cold Lake heavy crude oil. Approximately 3.6 hectares (ha) (8.8 acres) of farmland was affected by crude oil. Enbridge personnel, located at the company's Edmonton Control Centre (ECC), was immediately aware that the pipeline had ruptured. The ECC received a Supervisory Control and Data Acquisition (SCADA)-generated signal and alarm indicating that a loss of pressure had occurred along with an associated pipeline volume imbalance. The SCADA system indicated that the discharge pressure at the company's Regina pump station (kilometre [km] 704.202) had dropped from 4 668 kilopascals (kPa) (677 pounds per square inch [psi]) to 1 262 kPa (183 psi). The suction pressure at the company's Odessa pump station (km 761.971) had dropped from 917 kPa (133 psi) to 117 kPa (17 psi).

At 2100, the ECC commenced the shut-down of Line 3 between Hardisty, Alberta, and Superior, Wisconsin. At 2103, the ECC initiated remote sectionalizing valve closures at various locations on Line 3 from Craig, Saskatchewan (km 590.67), to Cromer, Manitoba (km 958.845). At 2129, the Pilot Butte Fire Department arrived at the occurrence site, having been notified by the ECC. The occurrence site was in an area of farmers fields, approximately 10.6 km downstream of the Regina pump station. At 2131, the ECC received a call from a local landowner, who was then advised to evacuate the area. At 2135, Enbridge emergency response personnel arrived on site and had already begun the process of securing the occurrence site and evacuating local residents when the Royal Canadian Mounted Police (RCMP) arrived at 2136 to provide assistance. At 1815, 21 May 1999, Line 3 was returned to service by isolating and bypassing the section of failed pipeline in the occurrence area. At 1551, 23 May 1999, Line 3 was returned to normal operations.

Ce rapport est également disponible en français.

Other Factual Information

The occurrence site was located within a road allowance, with landowners on either side. Enbridge's initial priority response was directed towards affected landowners, local emergency first responders, various regulatory agencies and the containment of the released product. Beginning at 2136 mountain standard time (MST)¹ on 20 May 1999, until 0130, 21 May 1999, Enbridge field personnel contacted 15 landowners and evacuated two residences pending the clean-up of spilt crude oil. Since the air was rich in hydrocarbon vapours which could have been ignited with the passage of a vehicle, this increased the urgency for Enbridge's field personnel and local first responders to secure and isolate the occurrence site from the general public. Once the occurrence site was secured, Enbridge's field personnel could then begin the task of contacting, and when required, evacuating local residents until such time as the area was declared safe (see Appendix A for a site plan of the occurrence site).

Enbridge has four parallel lines of pipe in the area:

- one designated as Line 1 with a nominal outside diameter of 508 mm (nominal pipe size [NPS] 20 inches) used principally to transport natural gas liquids and refined petroleum products;
- one designated as Line 2 with a nominal outside diameter of 610 mm (NPS 24 inches) used principally to transport light and medium crude oils;
- one designated as Line 3 with a nominal outside diameter of 864 mm (NPS 34 inches) used principally to transport light, medium and heavy crude oils; and
- one designated as Line 13 with a nominal outside diameter of 406.4 mm (NPS 16 inches) used principally to transport light crude oil.

The four pipelines are buried in a textured soil which typically consists of topsoil overlaying clay. While no major water bodies or water courses were affected by the spilt crude oil, the groundwater table is approximately 0.5 m to 3.5 m below the ground surface, with a southwesterly gradient.

The nominal wall thickness of Line 3 at the occurrence site is 7.92 mm (0.312 inches). The pipe was manufactured in 1968 at the Stelco Pipe Mill in Camrose, Alberta, with a double-submerged arc-welded (DSAW) longitudinal seam weld and a pipe grade of steel of 359 megapascals (MPa) (American Petroleum Institute [API] 5LX pipe grade X-52). The section of Line 3 which ruptured had been externally coated at the time of construction with one layer of self-adhesive polyethylene tape.

Once constructed, installed, and buried in the ground approximately 1.3 m, the section of pipe had been hydrostatically tested between 06 and 08 August 1968, to a maximum test pressure of 6 986 kPa (about 920 pounds per square inch gauge [psig]) at Mile Post 439.34, which corresponds to approximately 96 per cent of the specified minimum yield strength (SMYS), and a maximum test pressure of 6 257 kPa (about 824 psig) at Mile Post 445.94, which corresponds to approximately 86 per cent of the SMYS. The National Energy Board (NEB) had issued a "Leave to Open" to Enbridge at a maximum allowable operating pressure (MAOP) of 5 157 kPa (about 748 psig) which corresponds to about 76 per cent of the SMYS. Subsequently, this section of Line 3 had not been hydrostatically re-tested.

The ECC relies on selected telemetric data from pump and meter stations coming from Enbridge's SCADA telemetry network across the pipeline system to determine the optimum operating scenarios for moving

¹ All times are MST (Coordinated Universal Time [UTC] minus seven hours) unless otherwise stated.

contracted quantities of Western Canada hydrocarbons. On the day of the occurrence, but before the occurrence, no unusual situations were encountered by the ECC. A review of the telemetric data for 20 May 1999 shows that, before the break, Line 3 had been moving Cold Lake heavy crude oil at a constant flow rate of 4 000 m³ per hour (25 160 barrels per hour) with a discharge pressure of 4 981 kPa (656 psig) at the Regina pump station. At this time, Line 3 was just beginning to flow this grade of crude oil. All functions had been normal for the previous 24 hours.

Line 3 is protected against corrosion by a cathodic protection (CP) system, provided by an impressed current system on each of the four operating pipelines. The CP distribution system is located at the Regina pump station. In order to determine the effectiveness of the CP system and to ensure that the existing minimum industrial norm is met, Enbridge's field personnel and contract staff perform annual voltage potential pipe-to-soil surveys of the four pipelines. The survey records for the period between 1993 and 1998 indicated that the CP potentials at the rupture site showed good readings with the CP potentials consistently exceeding the minimum norm. The annual survey records also showed that, during the period from October 1998 to June 1999, the Line 3 rectifier located at the Regina pump station had been switched off because of construction-related activities in the pump station. Pipe-to-soil potential measurements taken at the occurrence site on 22 May 1999 obtained a CP reading above the relevant minimum industrial norm.

The metallurgical examination determined that Line 3 failed due to the presence of a longitudinal or radial corrosion fatigue crack coincident with the exterior toe of the longitudinal weld seam of the DSAW pipe. Radial corrosion fatigue is the effect of repeated or fluctuating hoop stresses in combination with a corrosive environment resulting in a shorter pipe life than would result from either repeated or fluctuating stresses or the corrosive environment working alone. This crack had grown along a transgranular path to a point where the pipe could not contain the estimated internal operating pressure of 3 627 kPa (526 psig), which corresponds to about 52 per cent of the SMYS. The cracking defect was found along the entire length of the 4.32 m (14.17 feet) longitudinal seam weld of the pipe. Metallurgical analysis of the crack indicated that this cracking defect varied from 13 to 36 per cent of the pipe wall thickness over the length of the joint of pipe and measured approximately 90 per cent of the wall thickness over a distance of 2.02 m (6.63 feet) in the vicinity of the fracture initiation. The origin of the crack is attributed to the combined result of a corrosive environment and applied cyclic hoop stresses. It is not known what effect, if any, vehicular traffic on the gravel road had in inducing applied cyclic hoop stresses. There was no indication that this crack was related to stress corrosion cracking (SCC) or hydrogen embrittlement (HE) as a result of the corrosion processes that had taken place. There was no indication of manufacturing defects or laminations which would have contributed to crack initiation or propagation. The measured mechanical, metallurgical and chemical properties of the pipe wall met all the requirements of applicable standards at the time of manufacture and construction.

Environmentally assisted cracking (EAC) is a generic term used to describe the cracking and fracture of metals under the combined action of stress and a corrosive environment, which is usually an aqueous environment. EAC, in an aqueous medium, may be classified into a number of sub-types, one of which is "corrosion fatigue" when the loading stress is cyclic in nature.

A new section of 34-inch pipe, which measured 34.16 m (112 feet) long, was used to replace the ruptured section of pipe.

There have been similar in-service pipeline ruptures on the Enbridge pipeline system attributed to longitudinal or radial corrosion fatigue cracks, coincident with the exterior toe of the longitudinal weld seam of the DSAW pipe, at the following locations:

- Mile Post 549.50, on 09 January 1989, investigated by the NEB;
- Mile Post 548.86, on 13 November 1995 (TSB report No. P95H0047).

Since June 1995, Enbridge has been conducting an aggressive in-line inspection (ILI) and excavation program of Line 3 (34-inch pipe). The purpose of the program is to evaluate the existence and severity of corrosion fatigue cracks, narrow, axial, external corrosion (NAEC), and externally initiated cracks inside areas of surface corrosion. This program has identified radial corrosion fatigue cracks, coincident with the exterior toe of the longitudinal weld seam of the DSAW pipe which had not yet failed, at the following locations:

- Mile Post 506.09, in January 1996;
- Mile Post 507.92, in January 1996.

The maintenance records for Enbridge indicate that the program identified 16 other locations on Line 3 requiring further evaluation by company field personnel in a 1 km vicinity on either side of the occurrence site, from Mile Post 443.4749 to Mile Post 444.9937. Once all 16 sites had been excavated, maintenance personnel found external pipe corrosion with a maximum pit/cluster depth ranging from 1.52 mm to 3.05 mm with a cluster/pit length ranging from 0.193 m to 4.568 m. After each location had been evaluated using an Engineering Assessment (EA) technique recommended by the current edition of Canadian Standards Association (CSA) standard CAN/CSA-Z662-99, entitled *Oil and Gas Pipeline Systems Standard*, the exterior surface of the pipeline was recoated at 10 of the 16 sites. The remaining 6 sites were first repaired using an external repair sleeve technique and then recoated.

To date, over 1 000 discrete locations have been excavated, assessed and remediated on Line 3. Details regarding the condition of the pipe and coating as well as site-specific environmental characteristics have been collected at each excavation site. The scope of this program has allowed Enbridge to amass a comprehensive database of soil side corrosion and cracks on liquid lines.

The appropriateness of the detection and assessment methodologies used by Enbridge was validated by the hydrostatic test results achieved in September 1996. During this hydrostatic test, no ruptures or leaks occurred when 198 km of Line 3 between Odessa, Saskatchewan, and Cromer, Manitoba, was tested at pressures corresponding to 100 per cent of the SMYS.

Enbridge continued this program into 1997 and 1998 to inspect the remaining sections of Line 3. Internal inspections using an ultrasonic metal loss tool have now been completed for all sections of Line 3 between Edmonton, Alberta, and Gretna, Manitoba, a distance of 1 245.12 km. The follow-up excavation program based on the ultrasonic metal loss data was carried out in 1997 and 1998. Also, in 1997, an internal inspection of Line 3 using a crack detection tool was completed between Cromer and Gretna, a distance of 283.56 km, and excavations based on these crack detection data were carried out in 1997 and 1998. During 1999, Enbridge conducted another 155 excavations on Line 3, based upon the results of the analysis of the corrosion detection ILI data. The primary purpose of this work was to validate the corrosion growth models developed from multiple inspections using corrosion-based ILI tools, while addressing some of the remaining, less severe metal loss indications. Inspections of the Edmonton-to-Kerrobert, Saskatchewan, and Kerrobert-to-Regina sections of

Line 3 using a crack detection tool have been conducted in 2000 with data analysis continuing into 2001. Before Enbridge collects these data, it will continue to implement another of its ongoing programs, namely the SCC Management Program for Line 3, by excavating in locations where SCC might exist. Before the occurrence, Enbridge's ongoing ILI program did not prevent the failure of Line 3 by identifying the presence of a radial corrosion fatigue crack at the occurrence site. Since the field investigation determined that the failed pipe contained a very narrow, shallow groove adjacent to the toe of the entire long seam of the joint of pipe, Enbridge has subsequently ascertained that this type of surface defect can be detected using current ILI technology.

In response to a corrosion-related pipeline rupture on Line 3, an overall integrity management program for Line 3 was developed by Enbridge's predecessor, Interprovincial Pipe Line Inc. (IPL). The purpose of this overall integrity management program was to determine whether similar corrosion-related and cracking patterns or mechanisms existed elsewhere on the pipeline system, and if some were found, to rectify the problem. On 27 February 1996, a rupture occurred on Line 3, at km 815.405, near Glenavon, Saskatchewan, where approximately 800 m³ (5 000 barrels) of heavy crude oil was released and collected in a low-lying area near the site. The Board determined that the rupture was caused by excessive NAEC located adjacent and running parallel to the longitudinal seam weld of the pipe, which was assisted by low-pH SCC and was not identified through the company's ongoing pipeline integrity program (TSB report No. P96H0008 has more details on this occurrence).

In effect since 1994, the current edition of CSA standard CAN/CSA-Z662-99, entitled *Oil and Gas Pipeline Systems Standard*, section 10.8.2, "Evaluation and Treatment of Localized External Corrosion Pitting on Pipe," permits localized corrosion pits to 80 per cent of the nominal wall thickness of the pipe, provided that the calculated maximum permissible length of the corrosion is not exceeded. The standard has the same corrosion limits as those specified in previous editions of CSA standards for oil pipelines, most notably standard CAN/CSA-Z183-M86, in effect from 1986 to 1990, and standard CAN/CSA-Z183-M90, in effect from 1990 to 1994. Earlier editions of the CSA standard were in effect in 1989 when Enbridge (formerly IPL) initially started the overall integrity management program for the purpose of detection, identification, evaluation and repair determination of zones of corrosion as well as any injurious cracking patterns or mechanisms. Using the formula set out in the CSA standard, the maximum allowable longitudinal length for the corroded area can be determined. During the application of the CSA standard, Enbridge found that, in numerous cases, the amount of corrosion damage on Line 3 exceeded the maximum length limits established by the CSA standard.

Since the CSA standards are viewed as very conservative with respect to corrosion criteria calculations, some pipeline operators use the EA method permitted by the CSA standard. Since the CSA does not provide permission in answer to requests to use a particular method, a pipeline operator will request a simple yes or no answer from the CSA Standards Committee in order to clarify the matter. In 1989, Enbridge sought such a request and received a yes reply from the CSA Standards Committee to use the Engineering Critical Assessment (ECA) method instead of the specific requirements outlined in section 10.8.2 of the CSA standard. However, the ECA was not designed to be applied to defects where cracks were coincident with metal loss. Section J.2.2 of Appendix J of CAN/CSA-Z662-99 standard, entitled "Recommended Practice for Determining the Acceptability of Imperfections in Fusion Welds Using Engineering Critical Assessment" states that "before accepting imperfections as tolerable on the basis of ECA, it shall be established that growth during service will not result in such imperfections exceeding the tolerable size."

Analysis

Historically, the self-adhesive polyethylene tape coating system, such as the system used by Enbridge on Line 3, has caused the pipe to become particularly susceptible to cracking defects. These defects are found coincident with the exterior toe of the longitudinal weld seam of the DSAW pipe under specific environmental conditions, such as those found at the occurrence site. This type of exterior coating system has also resulted in a much higher susceptibility to producing general surface corrosion and NAEC-type defect conditions. The coating system used on Line 3 has been found to develop both a tenting effect over the full length of the longitudinal weld of the joint of pipe as well as to become disbonded from and/or to deteriorate over the body of the pipe joint.

CP survey measurements taken by Enbridge field personnel over a period of several years indicated full CP coverage in the section of the pipeline system at the occurrence site. Enbridge field personnel confirmed on 22 May 1999 that the amount of impressed current at the occurrence site was above the minimum industrial norm even though the CP rectifier for Line 3, located at the Regina pump station, had been disconnected since October 1998. Since there were three other pipelines in the immediate vicinity of the occurrence, it is possible that CP protection was being provided by these other CP sources.

The triple situation of disbondment of the coating, the dielectric nature of the coating and the unique electrochemical environment established under the exterior coating, which acts as a shield to the electrical CP current, is referred to as CP shielding. The combination of tenting and disbondment permits a corrosive environment around the outside of the pipe to enter into the void between the exterior coating and the pipe surface. With the development of this CP shielding phenomenon, impressed current from the CP system cannot access exposed metal under the exterior coating to protect the pipe surface from the consequences of an aggressive corrosive environment. The CP shielding phenomenon induces changes in the potential gradient of the CP system across the exterior coating, which are further pronounced in areas of insufficient or sub-standard CP current emanating from the pipeline's CP system. This produces an area on the pipeline of insufficient CP defence against metal loss aggravated by an exterior corrosive environment. Radial corrosion fatigue cracks, coincident with the exterior toe of the entire longitudinal weld seam of the DSAW pipe, then develop and continue to grow. Of interest is the fact that the same mechanism applies to the creation and growth of NAEC-type defects coincident with the exterior toe of the entire longitudinal weld seam of the DSAW pipe. Metallurgical analysis of a section of the ruptured DSAW pipe by an outside consultant identified a radial corrosion fatigue crack coincident with the exterior toe of the entire longitudinal weld seam. This type of crack is part of a family of pipe cracking mechanisms generally referred to as EAC mechanisms, which have historically contributed to pipeline ruptures and leaks on Line 3 of the Enbridge pipeline system.

Since June 1995, Enbridge has been conducting an aggressive internal inspection and excavation program of Line 3 to evaluate the existence and severity of EAC mechanisms, corrosion fatigue cracks, radial defects, NAEC-type defects, and externally initiated cracks inside areas of surface corrosion, on the pipeline system. Over 1 000 locations on Line 3 have been excavated, and field examinations have been conducted with associated remedial action(s) undertaken by company personnel. At all field investigation sites on Line 3, Enbridge has found tenting, disbondment and/or deterioration of the exterior coating of the pipe over the full length of the longitudinal seam weld and at various locations on the pipe body.

The tenting of the coating adjacent to the longitudinal seam weld has been found to create a channel along which groundwater and associated ground mineral salts and ground bacteria can travel the length of a joint or joints of pipe. Mineral salts and bacteria in the soil, together with groundwater, when combined with CP shielding, act as a catalyst to accelerate the process of defect creation. However, the role played by ground-based mineral salts and bacteria in this process of disbondment and/or deterioration is not well known and not well understood. While much time and resources have been expended by Enbridge to understand radial defects and NAEC-type cracking defects phenomena, which are found coincident with the exterior toe of the entire longitudinal weld seam of the DSAW pipe on Line 3 of its pipeline system, little understanding exists as to the interaction between bacteria, groundwater, naturally occurring mineral salts, exterior coating primer, and polyethylene tape coating. What is known is that this interaction gives rise to the existence of radial or longitudinal defects, radial corrosion fatigue defects, EAC-type defects and NAEC-type cracking defects which are found coincident with the exterior toe of the entire longitudinal weld seam of the DSAW pipe on Line 3.

The section of Line 3 that ruptured had been internally inspected as part of this ongoing evaluation program. However, the program did not identify the presence of a radial corrosion fatigue crack coincident with the entire length of the exterior toe of the longitudinal weld seam of the DSAW pipe. Since 1995, much progress had been made in identifying sections of Line 3 that had been structurally weakened by the presence of cracking mechanisms. In addition, Enbridge has been working closely with the supplier of ILI equipment to perform detailed assessment of the adequacy of the ILI technology used. ILI tool capabilities have been analyzed by Enbridge using pull-through testing, manual ultrasonic comparisons and the results from hydrostatic testing in other sections of the pipeline. Other pipeline companies have carried out similar work.

In response to ruptures and leaks on Line 3, Enbridge established an overall integrity management program for Line 3 to determine whether similar cracking patterns or mechanisms existed on the pipeline system, and if present, to decrease or eliminate the potential for a pipeline rupture or leak. While the establishment of the overall integrity management program for Line 3 has merit, Enbridge's program has certain deficiencies. The overall integrity management program does not completely address the presence of radial corrosion fatigue cracks identified such as those found in this occurrence and does not specifically address the question of identifying those locations on Line 3 where areas of coating disbondment and/or degeneration exist.

Findings as to Causes and Contributing Factors

1. The rupture of Line 3 initiated in the zone of a radial corrosion fatigue crack that was located coincident with the entire length of the exterior toe of the longitudinal weld seam of the double-submerged arc-welded (DSAW) pipe.
2. Radial corrosion fatigue cracks are known to occur under self-adhesive, polyethylene exterior coating systems which, during the original installation, created tenting in the area either side of and along the toe of the longitudinal seam weld.
3. The tenting phenomenon of the exterior coating acted to shield the exposed pipe surface under the coating from the cathodic protection (CP) system and permitted the corrosive external environment to affect the exposed pipe surface.

4. The exterior environment around the buried pipeline contained catalysts, such as bacteria and mineral salts, which when mixed in an aqueous solution, have been found to be directly related to the initiation and propagation of radial corrosion fatigue cracks when combined with the cyclic operating stresses in pipelines.
5. Enbridge's overall integrity management program was not successful in identifying the presence of a radial corrosion fatigue crack zone at the occurrence site, possibly because it could not completely distinguish between groove-type defects and environmentally assisted cracking (EAC)-type defects, nor the rate of growth of the latter.

Other Findings

1. There have been three in-service pipeline ruptures and two locations on the Enbridge pipeline system attributed to the presence of a zone of radial corrosion fatigue cracking located in a zone coincident with and running parallel to the exterior toe of the longitudinal weld seam of the DSAW pipe.
2. Line 3 has had ruptures attributed to narrow, axial, external corrosion (NAEC), which has also been found in a zone adjacent to and running parallel to the longitudinal weld seam of the DSAW pipe.
3. One NAEC-type defect failure on Line 3 was found to have been assisted by low-pH stress corrosion cracking.

4. Since October 1998, the CP rectifier for Line 3, located at the Regina pump station, had been disconnected from the CP system. Two days after the occurrence, CP survey measurements at the occurrence site showed that the amount of impressed current exceeded the accepted minimum industrial norm.
5. Radial corrosion fatigue cracks and NAEC-type defects are both found in a zone running along the exterior toe of the longitudinal weld seam of the DSAW pipe under the tented exterior coating along the longitudinal seam weld of the pipe.
6. The Engineering Critical Assessment (ECA) technique used by Enbridge to determine whether a defect is acceptable or repairable was not designed to be applied to EAC-type cracking mechanisms.
7. Enbridge's ongoing in-line inspection (ILI) program of Line 3 has had limited success in identifying the presence of a radial corrosion fatigue crack even though the ILI program was designed to identify the presence of this type of cracking defect on Line 3.
8. Within a one-kilometre zone either side of the occurrence site, there were 16 zones of general pipe surface corrosion of varying lengths up to 4.568 m long. At 6 of these sites, a permanent pipeline repair was required because the self-adhesive exterior coating had disbonded and/or degenerated over time and permitted corrosion to develop and grow while being shielded from the CP system.

Safety Action Taken

In response to this occurrence, Enbridge initiated a number of actions which are outlined as follows:

- Based upon the results of testing, Enbridge initiated and completed a review of all existing field data to determine whether the re-analysis of the results of in-line inspection (ILI) would identify other locations on Line 3 for field excavation and field analysis. While 11 additional joints of pipe were selected as possible candidates, there were no additional longitudinal seam weld-type cracks found in this re-analysis. Field excavation and analysis of the two highest-ranked joints of pipe identified a corrosion groove between 5 and 10 per cent of the wall at one site and no indication at the second site.
- Revisions were made to Enbridge's Non-Destructive Testing Protocol and Field Training Program to ensure that indications previously dismissed as non-injurious weld anomalies are not labelled "insignificant" unless the indication has been confirmed as "insignificant" using an ultrasonic testing device and/or grinding off of the weld cap.
- The Regina-to-Odessa (km 704.202 to km 761.971) section of Line 3 was re-inspected with a more advanced ILI tool in July 1999. An additional 19 locations were identified on this section of Line 3 requiring further field analysis work. As each location is excavated and the field results collected, this information was then used to further refine the detection capabilities of the ILI tool. Enbridge has conducted evaluations of ILI technology and has verified that crack detection ILI equipment has the ability to detect grooving and subsequent cracking of the type causing the subject failure. This conclusion was based on testing of the ILI tool ultrasonic probes in combination with the results

obtained from investigative excavations at locations selected specifically to provide data related to this verification work.

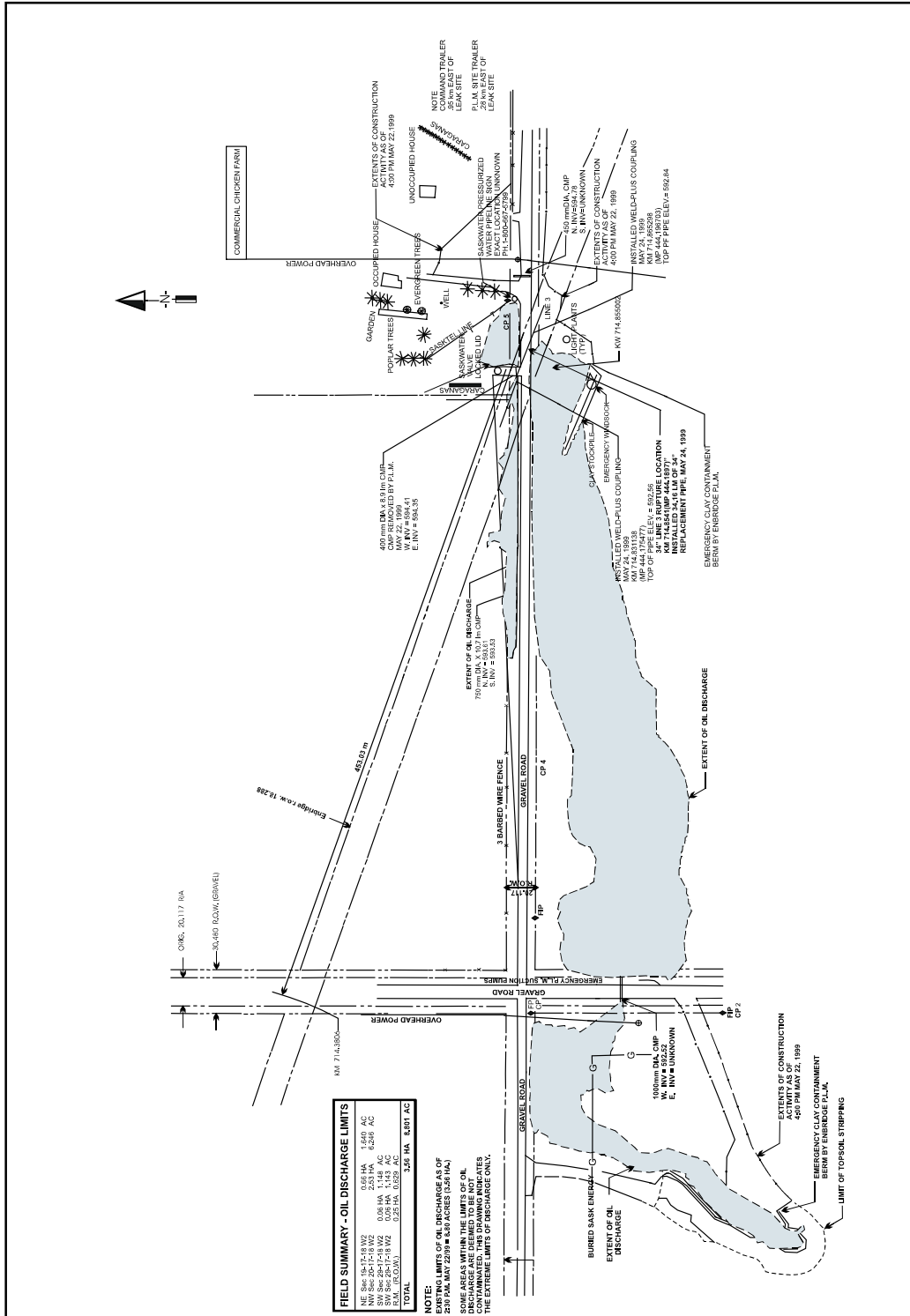
- Enbridge engaged the services of a consultant to evaluate fatigue susceptibility on Line 3. Two studies were carried out using actual Line 3 data and applying the theories of pure fatigue. The results of the studies were inconclusive as they did not correlate with actual experiences on Line 3. An additional study was commissioned by Enbridge that utilizes representative Line 3 pressure spectra in combination with a representative electrolyte.
- Since the mid 1990s, Enbridge has been collecting soil and groundwater samples for analysis of pH level, dissolved salt concentrations and resistivity at all excavation sites on Line 3. Because trending analysis of these data has been inconclusive, Enbridge has contracted with a consultant to perform a statistical assessment to determine if those samples could be linked to the occurrence of external fatigue cracking. The results do not provide insight regarding the relationship between soil and groundwater properties and the susceptibility of fatigue cracking.

Following the occurrence, the National Energy Board (NEB) initiated a series of meetings and operational compliance audits of Enbridge's activities to ensure that the company's activities addressed the NEB's concerns regarding the safe operation of Line 3 as well as the company's activities related to the protection of the general public and the environment during the company's response to an occurrence.

On 22 June 1999, NEB staff met with Enbridge officials to obtain a first-hand briefing regarding the changes to existing programs as well as an update on the company's activities in light of the occurrence of 20 May 1999. This meeting was followed by another meeting on 10 September 1999, where Enbridge officials provided a recap of events since the occurrence as well as an update on specific changes to company programs, procedures and internal inspection programs. This meeting was then followed by site-specific visits by NEB staff to locations being inspected by Enbridge to identify pipe surface anomalies similar to the type of defect found during this investigation. On 15 June 2000, NEB staff met again with Enbridge officials to obtain further information on the status of ongoing programs.

This report concludes the Transportation Safety Board's investigation into this occurrence. Consequently, the Board authorized the release of this report on 13 March 2002.

Appendix A—Site Plan of the Occurrence Site



Appendix B—Glossary

API	American Petroleum Institute
CP	cathodic protection
CSA	Canadian Standards Association
DSAW	double-submerged arc-welded
EA	Engineering Assessment
EAC	environmentally assisted cracking
ECA	Engineering Critical Assessment
ECC	Edmonton Control Centre
Enbridge	Enbridge Pipelines Inc.
ha	hectare
HE	hydrogen embrittlement
ILI	in-line inspection
IPL	Interprovincial Pipe Line Inc.
km	kilometre
kPa	kilopascal
m	metre
m ³	cubic metre
MAOP	maximum allowable operating pressure
mm	millimetre
MPa	megapascal
MST	mountain standard time
NAEC	narrow, axial, external corrosion
NEB	National Energy Board
NPS	nominal pipe size
psi	pound per square inch
psig	pound per square inch gauge
RCMP	Royal Canadian Mounted Police
SCADA	Supervisory Control and Data Acquisition
SCC	stress corrosion cracking
SMYS	specified minimum yield strength
TSB	Transportation Safety Board of Canada
UTC	Coordinated Universal Time