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NATIONAL ENERGY BOARD REPORT

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In the Matter of an Accident
on 19 February 1985
near Camrose, Alberta, on the Pipeline System
of Interprovincial Pipe Line Limited

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Recital and Appearances

IN THE MATTER OF the National Energy Board Act (NEB Act) and the Regulations made thereunder; and

IN THE MATTER OF an accident on 19 February 1985 near Camrose, Alberta, on the pipeline system of Interprovincial Pipe Line Limited; and

IN THE MATTER OF an inquiry held by the National Energy Board pursuant to Sections 20 and 39 of the NEB Act under Order No. MH-2-85.

HEARD at Edmonton, Alberta on 26, 27, 28, 29 and 30 March 1985, and 22, 23 and 24 October 1985.

BEFORE:	J.R. Jenkins J. Farmer A.B. Gilmour	Presiding Member Member Member
APPEARANCES:	D. Thomas A. Moen W.E. Omoth	Interprovincial Pipe Line Company
	T. Kulasa	Mrs. Mary Guthrie
	N.W.P. Boyle	Trans Mountain Pipe Line Company
	R.W. Riegert	Shell Canada Limited
	L. Keough A. Macdonald	National Energy Board

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Abbreviations

bbl/min	barrels per minute
Board	National Energy Board
C	carbon
CE	carbon equivalent
CPA	Canadian Petroleum Association
CRT	cathode ray tube
CSA	Canadian Standards Association
CSA Z183	Canadian Standards Association Standard Z183 entitled "Oil Pipeline Transportation Systems"
ECA	Engineering Critical Assessment
ERW	electric resistance welded
HAZ	weld heat affected zone
HVP	high vapour pressure
IPL	Interprovincial Pipe Line Limited
km	kilometres
KmP	Kilometre Post
kJ/mm	kilojoules per millimetre
kPa	kilopascals
LEL	lower explosive limit
Line No. 1	Interprovincial Pipe Line Company Limited's Line No. 1
MST	Mountain Standard Time
mm	millimetres
m	metres
m^3	cubic metres
m^3/hr	cubic metres per hour
Mn	manganese
NEB	National Energy Board
NGL	natural gas liquids
O.D.	outside diameter
P	phosphorus
P.S.	pump station
Regulations	National Energy Board Oil Pipeline Regulations
RCMP	Royal Canadian Mounted Police
RPP	refined petroleum products
S	sulphur
W.T.	wall thickness

Definitions

analogue check — The routine comparison of pressure readings between the computer control centre and the pump station. This work is performed on a monthly basis by the shift dispatcher in consultation with remote station personnel.

backfire — Backfire arises because of the premature explosion of hydrocarbon vapours in an internal combustion engine cylinder or in the engine's exhaust pipe.

calculated flow — Flow between two pump stations is calculated by the control centre computer on a continuous basis using the upstream station discharge pressure, downstream station suction pressure, description of the section between pump stations, line fill information deduced from the last batch track record, temperature of the product, and other pertinent information.

case pressure — The pipeline pressure recorded in the pump station piping downstream of the pump(s) and upstream of the pump station control valve.

differential section pressure — The difference in pressure between the upstream pump station discharge pressure and the downstream station suction pressure.

discharge pressure — The pipeline pressure recorded in the pump station piping downstream of the pump station control valve.

fillet weld — A weld of approximately triangular cross section joining two surfaces approximately at right angles to each other in a lap joint, T-joint or corner joint (reference Appendix VI for drawing).

grade X52 line pipe — Steel line pipe fabricated to meet the requirements of the American Petroleum Institute specification entitled "5LX High-Test Line Pipe".

heat affected zone — The area of the parent metal surrounding a weld which has undergone a microstructure change due to the input of heat from welding.

historicals — Computer records which reflect information for each station such as operation pressures, pressure set points, status of pump units and other information. This material can be retrieved for a period of up to four hours and displayed on the operator's screen. These records cover information at four-minute intervals for the preceding four hours.

Linalog — A registered trade mark of AMF Inc. designating its internal inspection tool used to identify pipeline corrosion.

lock-out — When the suction pressure drops below the station suction pressure set point, the station control automatically shuts down the pump unit, thus protecting the station from low suction pressure.

natural gas liquids — A description of natural gas liquids is provided in Section 2.5.2 of this report.

rimmed steel Steel which is cast into ingots following steelmaking and which is allowed to solidify without the addition of specific agents for deoxidation.

semi-killed steel Steel into which sufficient amounts of deoxidizing agents have been added following steelmaking to remove a portion of the dissolved oxygen.

stopple A registered trade mark of T.D. Williams Inc. designating its equipment for plugging high pressure pipelines.

suction pressure The pipeline pressure recorded on the upstream side of the pump station.

throttling When the suction pressure, the pump case pressure, or the pumps exceed pre-set normal conditions, the station control valve, which is located downstream of the pumps, reacts automatically to restrict the flow. This causes a reduction in the output pressure from the pumps resulting in a lower discharge pressure and a lower pressure downstream of the control valve.

throttling on suction When a pump station is operating at high flow, the suction pressure can drop below the suction pressure set-point. When this situation occurs, the station control valve, which is located downstream of the pumps, reacts automatically to restrict the flow. This causes the pump output pressure to decrease across the control valve.

weld + end A registered trade mark of Plidco International Inc. designating its design of a pipe coupling device

Chapter 1
Synopsis and Introduction

1.1 Synopsis

About 12:23 hrs. M.S.T. on 19 February 1985, there was a leak on IPL's 508 mm diameter pipeline which allowed natural gas liquids to escape into the atmosphere. The site of the failure was on the edge of a slough located in a farmer's field, approximately 27 km northeast of Camrose, Alberta. Approximately nine hours later the escaping natural gas liquids ignited. The ensuing fire killed two persons and severely burned three others. In addition, approximately 2 800 m^3 of NGL was lost and a 3/4-ton pick-up truck, a 2 1/2-ton flat-bed truck and a station wagon were destroyed and two other pieces of excavating machinery and a lighting plant were damaged.

The National Energy Board has determined that the cause of the release of NGL was the failure of a fillet weld on a full encirclement sleeve. The fillet weld failed due to a hydrogen induced crack. Ignition of the escaping NGL vapours occurred at or about 20:30 hrs. M.S.T. A wind direction change of approximately 180° caused the NGL vapours to drift towards the site where the pipeline maintenance crew, preparing the site for repair, had left vehicles parked with the engines running. The accident might have been avoided had the pipeline repair crew flared the escaping NGL gas vapours or had they been located on higher ground further from the leak site and had the pipeline crew been equipped with and made use of additional lower explosive limit gas detectors and wind direction monitoring devices.

1.2 Introduction

Interprovincial Pipe Line Limited (IPL) and its wholly-owned subsidiary, Lakehead Pipe Line Company Inc. (Lakehead), own and operate, as a common carrier, a pipeline system stretching 3 800 km from Edmonton, Alberta to Montreal, Quebec. IPL's head office is located in Toronto, Ontario. The pipeline system consists of three parallel lines, designated Lines No. 1, 2 and 3, from Edmonton to Superior, Wisconsin. In addition, some areas have been looped by a fourth line designated Line No. 4. Additional pipelines are in place between Superior and Sarnia, Ontario in order to feed the Toronto, Buffalo, Chicago, New York and Montreal markets.

IPL pumps a wide variety of products such as crude oil, gasoline, jet fuels, heating oil, diesel fuel and natural gas liquids (NGL). The most hazardous of these products is NGL.

IPL is subject to regulation by the National Energy Board (Board) under the National Energy Board (NEB) Act. In accordance with the Regulations made pursuant to the NEB Act, the leak was first reported to the Board by IPL at 20:00 hrs.* on 19 February 1985 and the subsequent fire was reported at 00:30 hrs. on 20 February 1985. In light of the serious nature and the tragic consequences of the leak, the Board held a public inquiry into the accident pursuant to Board Order No. MH-2-85.

The public inquiry was held in Edmonton, Alberta in two phases. Phase I commenced on 26 March 1985 and was adjourned on 30 March 1985. Phase II took place from 22 to 24 October 1985.

The purpose of the inquiry was to permit the Board to determine whether any changes should be made either in the way that IPL operates or the way in which IPL is regulated by the Board, in order to prevent similar accidents in the future. The Board in its opening statement to the Public Inquiry stated that depending on the evidence, the Board may find it necessary to use its powers under Section 39 of the National Energy Board Act to order the Company to make changes to its pipeline, or to make changes to the Regulations under the NEB Act governing the construction and operation of the pipeline. The Board also wanted to determine whether there had been any breach of the NEB Act or existing Regulations that could have contributed to the accident.

The areas of investigation were set out in the Directions on Procedure, Order No. MH-2-85, and are as follows:

1. the circumstances surrounding the accident and the probable cause of the accident;

* All times are Mountain Standard Time.

2. the condition of the pipeline at the location of the break, including any external repairs previously undertaken at the same location;

3. operating conditions of the pipeline preceding the break;

4. the use of sleeves as a repair technique on the pipeline;

5. the operations, maintenance and safety procedures, including training of employees, applicable to company responses to leaks in the pipeline, and especially leaks of natural gas liquids; and

6. possible measures to prevent a recurrence of the accident.

The mandate of the Board with respect to this inquiry derives from Sections 20 and 39 of the NEB Act. Section 20 provides that the Board may hold a public hearing in respect of any matter if it considers it advisable to do so. Section 39 provides that the Board's mandate is to promote safety in the operation of a pipeline and that it is expressly empowered to make regulations providing for the protection of property and the environment and the safety of the public and of the company's employees in the construction, operation and abandonment of a pipeline.

Chapter 2
Investigation

2.1 Circumstances Surrounding the Accident

On 19 February 1985 the pipeline control operators commenced their daily shift at the Edmonton Terminal Control Centre (terminal) rather than IPL's main Jasper Street control centre. This procedure is consistent with the Company's policy which stipulated that one shift per month must be operated from the terminal in order to familiarize operators with the back-up terminal control centre.

The morning shift started at 07:00 hrs. The terminal operating consoles are identical to those located at the main control centre. Mr. Richard Dickhouf, an operator trainee, was operating Lines No. 1 and 3 from the start of his shift.

Prior to 11:56 hrs., IPL was injecting a 34 102 m^3 batch of NGL into Line No. 1 at Edmonton. At the same time, IPL was delivering refined petroleum products (RPP) out of Line No. 1 at IPL's Regina pump station. At 11:56 hrs. the injection of NGL into Line No. 1 at the Edmonton pump station was completed and the injection of a batch of synthetic crude oil began. This change in product stream caused the discharge pressure at Edmonton to increase. After 11:56 hrs., the suction pressure at the next downstream station, Hardisty, had started to increase reflecting the increase in pressure in the pipeline due to the introduction of synthetic crude oil.

At 12:23 hrs., in order to reduce the high suction pressure at the Hardisty pump station, Mr. Dickhouf requested the Edmonton terminal operator to decrease the pumping horsepower at Edmonton. At about 12:24 hrs., a rapid drop in suction pressure at the Edmonton station was noted followed a few seconds later by a drop in suction pressure at Hardisty. These pressure fluctuations were attributed to the change in pump units at Edmonton. The Edmonton pump station then began to throttle on low suction pressure. A check with station personnel as to possible problems with pump units indicated that everything was satisfactory. Monitoring of pipeline operations continued.

At 12:37 hrs., pump unit no. 1.3 at the Edmonton pump station automatically shut down and locked out. Mr. Dickhouf contacted his supervisor, Miss Wendy Nicholson, to discuss the Line No. 1 situation and review the previous operating information. At about 12:42 hrs., a further check with the Edmonton terminal operator was made to determine whether the lock-out was caused either by booster pump or by valve-related problems. The operators concluded that no such problems existed. After completion of the review of the Line No. 1 operating conditions, Mr. Dickhouf and Miss Nicholson informed Mr. Ed Trudel, the senior shift dispatcher, of the operating conditions on Line No. 1. He reviewed the Line No. 1 data and noted the following:

1. unit no. 1.3 had locked out at the Edmonton pump station;
2. unit no. 1.1, also at Edmonton, was in the starting sequence; and
3. the Hardisty pump station was throttling on low suction.

He attributed the third point to the lock-out of the pump unit at Edmonton. As unit no. 1.1 at Edmonton began pumping, the line appeared to slowly return to normal operating pressure. Mr. Trudel suggested decreasing the pumping power out of Hardisty to eliminate the throttling problem. This was done and the suction pressure began to rise. At this point Mr. Trudel suspected a leak because of the slow pressure increase between Edmonton and Hardisty.

At approximately 13:00 hrs., a telephone call was received by Mr. Trudel from Mr. Ken Lien, a landowner, reporting a vapour cloud in a field adjacent to the Ryley road located approximately 27 km northeast of Camrose (see Appendix I). At about 13:03 hrs. Mr. Trudel instructed Mr. Dickhouf and Miss Nicholson to shut down Line No. 1. Then he advised Mr. Lien of the hazards of NGL and requested that he assist IPL in the barricading of the road until IPL personnel arrived at the site. Mr. Trudel informed Mr. Merv Guthrie, maintenance foreman of the IPL Edmonton pipeline maintenance crew, and Mr. Joe Smith, terminal foreman at the Edmonton terminal, of the Line No. 1 pipeline leak.

Mr. Smith, in turn, notified Mr. Bert Sirois, IPL District Manager, Operations District No. 1 and Mr. Wayne Sartoré, District Engineer, of the leak. Two IPL electrical maintenance personnel based in Camrose, Mr. Mark Stronski and Mr. Terry Wagner, were dispatched to the leak site to man road barricades.

Between 13:00 and 14:00 hrs., a passing motorist informed the Royal Canadian Mounted Police (RCMP) detachment in Camrose about the vapour cloud. The RCMP relayed this report to IPL's head office in Edmonton. IPL requested RCMP assistance in detouring traffic on the Ryley road. The IPL Kerrobert maintenance crew was also alerted and requested to respond to the leak. They were to be used to relieve the Edmonton crew.

At approximately 14:30 hrs. Messrs. Guthrie and John Armstrong, a pipeline maintenance man, arrived at the north barricade on the Ryley Road in Mr. Guthrie's station wagon. Shortly afterwards, other pipeline maintenance personnel, Messrs. Doug Bone, Les Cowie, Kerry Kelsey and Richard Wack began arriving. These men arrived in two vehicles, a 3/4-ton pickup truck and a 2 1/2-ton welding truck. Messrs. Bone and Cowie were assigned to man the south barricade on the Ryley Road (see Appendix II). Messrs. Kelsey and Wack were instructed to return to Edmonton and load equipment for the repair work.

At this time, weather conditions at Edmonton International Airport, the nearest official weather recording office to the leak site, were overcast, with a west by southwest wind blowing at approximately 11 km/h and temperatures in the range of 0 to +2°C. The airport is approximately 75 km due west of the leak site. The site itself had a light cover of snow.

At the time of the leak the IPL maintenance crews were equipped with two lower explosive limit (LEL) gas detectors. One instrument was carried by the maintenance foreman in his vehicle while the other was kept in the 2 1/2-ton welding truck. Between 14:30 and 16:00 hrs., using these two LEL gas detectors, IPL maintenance personnel conducted a detailed survey of the leak site, the Ryley Road and nearby residences to the west of the leak site (see Appendix II).

At about 15:30 hrs. Mr. Sartore arrived at the north barricade on the Ryley Road. Messrs. Sartore and Guthrie surveyed the leak area using Mr. Guthrie's LEL gas detector and approached to within approximately 12 m of the leak from the upwind or southwest side (see Appendix III). They noted that the ground over the pipe had been pushed upward in two places at the point where the NGL was spewing out of the ground. At approximately 16:30 hrs. using radio communication, Mr. Sartore provided Mr. Sirois, at the Edmonton terminal, with an assessment of the situation at the leak site. Mr. Sartore outlined the wind direction, the area of a liquid pool on the snow, the disturbed ground, the spewing gas, the fact that the leak was located in or near a slough and the high ground to the northwest. Mr. Sartore also told Mr. Sirois that it was a major break and the option of flaring should be seriously considered for three prime reasons:

1. the uncertainty of gas pocket locations;
2. the fact that without flaring they would be relying on the wind maintaining its direction; and
3. that darkness would be on them in an hour and one-half.

Mr. Sartore indicated that there were pockets located in a low-lying area which appeared to contain NGL vapours.

Mr. Sirois responded that he was hesitant to flare and gave the following reasons:

1. because of his past experience with a pipeline fire where two men had been killed;
2. that flaring would delay the completion of repairs; and
3. that, with the wind direction and the barricades on the Ryley Road, the situation was under control.

Instead, Mr. Sirois recommended that work begin on installing an upstream stopple and that the flaring option be discussed later.

From his office at the Edmonton terminal, Mr. Sirois contacted Mr. Don Ross, Director of Operations, and informed him of the line break situation. Mr. Sirois expressed his reluctance to flare, citing the three reasons he had previously given Mr. Sartore to support his position. Mr. Sirois did not relay the recommendation of Messrs. Guthrie and Sartore to flare the escaping vapours. Mr. Ross gave Mr. Sirois full permission to flare the escaping vapours if it was felt necessary.

At about 17:20 hrs., Mr. Sirois again spoke with Messrs. Guthrie and Sartore by radio and told them that he (Mr. Sirois) was still reluctant to flare unless the people in the field believed it to be 100 percent safe and saw no other option. It would then be their prerogative as supervisors on site to consider flaring. Mr. Sirois again recommended the installation of an upstream stopple. At this point, Messrs. Sartore and Guthrie, the supervisors on site, concluded that the option of flaring had been ruled out for the time being. Mr. Sirois, in his testimony, stated that he never considered the option of flaring to have been ruled out.

on the Caterpillar while spraying "Quick-Start", an ether- based chemical, into the air intake of the engine. This attempt was also unsuccessful and Mr. Froese suggested they try to jump-start the unit using the Gradall which had a more powerful 12-volt battery. The Caterpillar tractor was moved away and the Gradall was brought alongside. Again, using Quick-Start and the Gradall's battery, they attempted to start the lighting plant. During this attempt the lighting plant backfired and flames shot out from the exhaust. Finally the unit started and the Gradall was moved away and parked. Shortly after, the lighting plant stalled again and the Gradall was brought back to restart the lighting plant. During this time, Mr. Armstrong was also instructed by Mr. Guthrie to take the line locating equipment and commence locating the three pipelines in the area. However, he could not perform this task because he found that the unit was not functioning due to drained batteries.

Coincident with the activities at the leak site and shortly before 20:30 hrs., Messr. Ross and Don Savard, Western District Manager, arrived at the Edmonton terminal. Their plan was to pick-up Mr. Sirois and proceed to the leak site.

At about 20:30 hrs., Messrs. Kelsey, Wack, Armstrong and Bone were discussing the smell of gas in the air around them. Mr. Wack again informed Mr. Guthrie of the presence of the extra gas detectors at the leak site. Messrs. Armstrong and Wack had also noticed what appeared to be a ground fog around their legs. Also they noted the vehicles were stalling or idling roughly and the lighting plant again had stalled. At this point in time Mr. Kelsey got into the 2 1/2-ton truck to either shut it off or restart it. Almost immediately Mr. Froese saw a ball of flame erupt in the cab of Kelsey's truck and quickly engulf the whole leak site. All six men at the site were caught in the fire ball. Only Mr. Bone was able to escape unhurt. In addition, six pieces of equipment were destroyed or damaged. The location of this equipment at the time is shown in Appendix III.

The fire burned for almost two days, until about 19:00 hrs., on 21 February 1986, when the fire was extinguished by introducing nitrogen into the pipeline simultaneously from two stopple valve sites located upstream and downstream of the accident site.

2.2 Injuries as a Result of the Accident

Mr. Merv Guthrie and Mr. Kerry Kelsey received third degree burns to 80 percent and 90 percent, respectively, of their bodies. Both men died in hospital some time later.

Mr. John Armstrong and Mr. Dennis Froese received third degree burns to 50 percent and 70 percent, respectively, of their bodies.

Mr. Richard Wack received third degree burns to 30 percent of his body.

Mr. Doug Bone was uninjured.

2.3 Damage to Vehicles and Equipment and Loss of Product

A station wagon, a 3/4-ton pick-up truck and a 2 1/2-ton truck were destroyed in the fire. The Gradall, the Caterpillar tractor model no. 955 and the lighting plant were slightly damaged by the fire. It is estimated that approximately 2 800 m^3 of a mixture of propane, butane and condensate was lost as a result of the pipeline break and fire.

2.4 Previous Pipeline Repairs at the Accident Location

On 19 February 1985, IPL's Line No. 1 suffered a break at KmP 84.12. The carrier pipe fractured adjacent to a full encirclement sleeve which had been installed on 26 July 1973 (see Appendix VI).

Full encirclement sleeves have been used by IPL for repairing areas of the pipeline which have sustained damage by corrosion, dents, gouges, buckles and other similar causes. The sleeve in question at KmP 84.12 was installed over a series of corrosion pits which had penetrated through 60 percent of the pipe wall thickness at their deepest point. The maximum axial length of the pitted area, including interaction between defects, was 75 mm.

Every five to six years, IPL surveys its pipelines for corrosion damage using an internal inspection tool referred to as a "Linalog" pig. Anomalies detected by the inspection tool are excavated and inspected by IPL's maintenance crews. If corrosion pitting is found, an evaluation is made of its severity by considering pit depth and length. Criteria for the evaluation of the severity of the corrosion pit and the method of repair have been established by IPL in the form of tables. The crew foreman consults the tables to determine whether the corrosion pit may be cleaned and recoated only, or if the installation of a sleeve is required.

A Linalog survey of Line No. 1 between Edmonton and Hardisty was done early in 1973. The results were forwarded to Edmonton district authorities on 15 March 1973. The survey indicated the presence of corrosion at KmP 84. The area was excavated, inspected, and a sleeve was welded to the pipeline at KmP 84.12 on 26 July 1973. The design of this sleeve was similar to that shown on IPL drawing no.: A-3.701-6250-0-0, dated 12 July 1973 (see Appendix IV). The sleeve had a length of 406 mm. Its ends were fillet welded to the carrier pipe forming a closed vessel capable of retaining pressure. IPL has performed such welding routinely while the pipeline has been filled with liquid and in service.

IPL's Welding Procedure Specification WP-2, dated 9 February 1973, was in effect at the time of the installation of the sleeve at KmP 84.12, and was used for the fillet welding of the sleeve to the pipeline. However, this procedure had not been qualified in accordance with the requirements of the applicable CSA Z183 in force at that time. Following completion of installation of the sleeve at KmP 84.12 in 1973, nondestructive testing of the welds was not performed by means such as radiography, ultrasonics or magnetic particles. As the normal practice is to perform an external visual inspection of newly completed welds, IPL's pipeline maintenance crew would likely have performed a visual inspection of these welds.

Once the sleeve installation was completed, the pipeline was backfilled using the previously excavated material. No special pipe padding or backfilling procedures were employed. Since the work was being performed in summer, frozen backfill material was not present.

On 17 December 1981, IPL installed a second sleeve, 4.7 m downstream of the sleeve installed at KmP 84.12 in 1973. It is possible that, while excavating the pipeline to inspect for corrosion in 1981, the soil, on which the previously installed sleeve rested, may have been disturbed. Ultrasonic testing was performed on the newly installed sleeve six days later. During these six days, freezing of the excavated material would likely have occurred. If this frozen soil was then used for backfilling it is likely that it would have been placed around the pipe with very little compaction which could have resulted in inadequate support of the pipe. The new sleeve was of a size and design similar to the first. It too was intended to reinforce a series of non-leaking corrosion pits (see Appendix VI).

A number of other full encirclement sleeves were present on Line No. 1 in the vicinity of KmP 84.12 as well. The 730 m segment of Line No. 1, from KmP 83.8310 to KmP 84.5617, contained a total of 16 sleeves at the time of the break on 19 February 1985.

The portion of Line No. 1, between approximately KmP 83.90 and 84.11, lay in a slough, a low-lying swampy area. The sleeve at KmP 84.12 was located at the eastern edge of the slough in a transition zone between dry and wet ground.

2.5 The Pipeline System

2.5.1 Description of the IPL Pipeline System

The IPL pipeline system between Edmonton, Alberta and Gretna, Manitoba, essentially consists of three parallel pipelines. In addition, some areas have been looped by a fourth line.

Line No. 1, the original IPL pipeline, was constructed during the summer of 1950. The pipe diameter is 508 mm, decreasing to 406.4 mm downstream of Regina. Line No. 2, 610 mm in diameter, was constructed in stages between 1953 and 1958, while Line No. 3, 864 mm in diameter was begun in 1962 and completed in 1969. The first loops of the 1219 mm Line No. 4, were installed in 1973, however, to date, this line has not been completed.

The closest pumping facilities to the KmP 84.12 break site were at the Edmonton terminal, KmP 0.00 (upstream), and at the Hardisty station, KmP 175.45 (downstream). At KmP 84.12 the Line No. 1 pipe was nominally 508 mm O.D. x 7.9 mm W.T. The specified minimum yield strength was 359 Mpa. The pipe had been manufactured by A.O. Smith, using the longitudinal seam, flash welding method.

For protection against corrosion, the pipe had been coated in the field at the time of laying, using a coal tar enamel reinforced with fibre wrap. An additional barrier to corrosion was provided by a cathodic protection system employing impressed current and sacrificial anodes.

A schematic of the IPL Line No. 1, between Edmonton and Hardisty stations, is provided in Appendix I. Mainline sectionalizing valves and station locations are shown, as well as the location of the line break at KmP 84.12. Table 1 gives additional information with respect to each valve location, including whether the valve is operated by hand or by power or if remotely operated.

Upstream of the break location, the nearest Line No. 1 sectionalizing valve was the remotely operated valve located at KmP 69.40 at an elevation of 757.428 m. Downstream, a hand-operated valve was located at KmP 93.84 at an elevation of 703.478 m, and a remotely operated valve was located further downstream at the Strome station, KmP 112.19. at an elevation of 690.372 m.

On 20 September 1976, Line No. 1, between KmP 50.9 and KmP 111.5, successfully underwent hydrostatic re-testing. The line was subjected to a test pressure of 8673 kPa for 8 hours. A maximum operating pressure of 6521 kPa was subsequently authorized by the NEB. The pressure at the time of failure on 19 February 1985 was estimated by IPL to be 4756 kPa.

2.5.2 Natural Gas Liquids

Natural gas liquids (NGL) consist of a group of compounds in the light hydrocarbon range found in natural gas wells. NGL are stripped out of the natural gas and are used as a feedstock for the petrochemical industry.

While under elevated pressure, NGL exist in a liquid form. However, when released to the atmosphere, NGL vaporize and cool the surrounding air, condensing any water vapour and causing it to appear as a white fog. Because of this cooling property, NGL splashed on the body will have a freezing effect.

NGL vapours are heavier than air and will collect in low-lying areas or ground depressions. They tend to move with wind or downhill by gravity.

The lower and upper limits of flammability indicate, respectively, the percentage of NGL vapours in air below which and above which flame will not propagate. Mixtures within these limits are extremely flammable.

If air containing concentrations of NGL vapours of 5 percent or less than the lower flammable limit is inhaled, most people will not notice any effects. However, breathing air containing higher concentrations can have an intoxicating effect followed by unconsciousness due to a lack of oxygen.

The NGL stream involved in this accident was composed of 45 percent propane, 35 percent butane and 20 percent condensates by liquid volume. Condensates, sometimes referred to as natural gasoline, are liquid hydrocarbon mixtures formed in gas recycling plants through the expansion and cooling of the gas stream. The lower and upper flammable limits were, respectively, 1.1 percent and 9.5 percent. The pure propane and butane portions of an NGL mix are almost odourless. However, the condensates have an odour similar to gasoline but stronger and more unpleasant.

2.6 Metallurgical Examination of the Line Break

At the request of IPL, the Welding Institute of Canada carried out a metallurgical investigation of the Line No. 1 failure which occurred on 19 February 1985. Examination of the break revealed that Line No. 1 failed in the immediate vicinity of a full-encirclement sleeve that had been welded to the carrier pipe. The fracture occurred along the toe of the sleeve to pipe fillet weld and was observed to have initiated at the bottom of the pipe at the six o'clock position (see Appendix VI).

Further examination revealed that the fracture originated from a crack, 483 mm in length, situated in the heat affected zone (HAZ) associated with the sleeve fillet weld. The crack followed exactly every ripple of the fillet weld toe where it met the outside surface of the pipe. The crack had penetrated to a maximum 2.97 mm or 37 percent of the pipe wall thickness.

The crack in the weld HAZ was determined to have been caused by a hydrogen induced cracking mechanism. The metallurgical investigation determined that the crack had been formed at the time of the installation of the sleeve in 1973.

Final failure occurred due to the sudden propagation of the pre-existing crack, by brittle cleavage, when the level of longitudinal strain in the pipeline at the defect location exceeded a critical value. The strain required to produce defect propagation was estimated by calculation (Engineering Critical Assessment). It was shown that an applied axial strain of close to 0.2 percent would be necessary to initiate brittle fracture from the pre-existing crack. Since operating pressures were not sufficient to produce such axial strains, other mechanisms causing downward bending of the pipe, such as loss of ground support or frost heave, were likely responsible.

The chemical composition of the line pipe steel was typical of the pipe manufactured for the early IPL lines, as well as other pipeline systems of that period (see Table 2). These steels are characterized by high carbon content relative to the high strength pipe steels manufactured after the early 1970's. This elevated carbon content, combined with the high cooling rates associated with welding on liquid-filled pipe, resulted in a hardened martensitic HAZ microstructure, extremely susceptible to hydrogen cracking.

The solidification patterns on the fillet weld surfaces showed that the welds had been deposited using a vertically downward progression.

Testing proved the tensile properties of the pipeline involved in the failure to be well above the minimum requirements. There was no evidence of crack growth in service due to metal fatigue.

2.7 Similar Breaks on the IPL System

2.7.1 Pipeline Incident of 23 February 1983

On 23 February 1983, a pipeline break occurred on IPL Line No. 1 at KmP 82.3. In many respects, this break was similar to the one at KmP 84.12. The line suffered a complete circumferential fracture in the immediate vicinity of a full encirclement sleeve (see Appendix VII).

The sleeve at KmP 82.3 was installed on 9 February 1982, approximately one year before the pipeline break. The ends of the sleeve were fillet welded to the pipeline while it was liquid-filled and operating under reduced pressure. The design of the sleeve was similar to that shown on IPL drawing D-3.0-9249-0-0 (see Appendix IV). It was 610 mm in length.

IPL welding procedure specifications UF-04 and UF-08, both dated 21 October 1981, were in effect during February 1982 and were applicable to the fillet welding of sleeves onto the pipeline. Testimony indicates that UF-04 was the procedure used to perform the sleeve to pipe fillet welds at KmP 82.3. IPL began qualifying fillet weld procedures after 1980 and UF-04 was tested and qualified in accordance with the requirements of CSA Z183 under this Company policy. Qualification of a welding procedure involves carrying out various tests stipulated by the CSA Z183, the objective of which is to demonstrate that welds having suitable mechanical properties and soundness can be made by the procedure in question.

The fillet welds performed on 9 February 1982 for the installation of the sleeve at KmP 82.3 were ultrasonically inspected some eight days later. No defects were found.

Since the installation of this sleeve was carried out in winter, the soil used for backfilling would likely have frozen to a significant extent. The sleeve was located in the transition area between an open field and a slough.

Following the 23 February 1983 break, a metallurgical failure investigation was carried out by the Welding Institute of Canada at the request of IPL. It was found that final failure occurred due to sudden propagation by brittle cleavage, of a pre-existing hydrogen crack. The defect was centred about the six o'clock position on the pipe, was approximately 210 mm in length and had penetrated to a maximum depth of 3.7 mm or about 46 percent of the wall thickness. There was some evidence of limited crack growth by metal fatigue prior to the final failure.

The chemical composition of the carrier pipe involved in the failure is given in Table 2. In addition, the pipe steel was heavily segregated exhibiting carbon contents of 0.4 percent and higher in the region of failure. The chemical composition and segregation are typical of the early rimmed, grade X52, pipeline steels manufactured prior to the early 1970's. The carbon equivalent of the failed pipe (0.49 percent), was significantly outside the range of validity of IPL welding procedure UF-04 (0.41 percent max).

The microstructure of the fillet weld coarse grained HAZ, in which the hydrogen induced cracks had initiated, consisted entirely of martensite, a microstructure extremely sensitive to hydrogen induced crack formation.

Propagation of the pre-existing hydrogen crack and final failure occurred when either the crack grew slightly in service to a critical size or when the stress acting on the defect increased to a critical level. The latter may have been due to a change in service conditions, ground temperature or a loss of pipe support.

The sleeve at KmP 82.3 had been welded over numerous corrosion pits, the deepest having penetrated 3.20 mm or 40 percent of the wall thickness. Upstream of the failure location two additional 305 mm long sleeves were present within 4.0 m. A 915 mm long sleeve was present within 2.6 m downstream of the fracture. Thus within a distance of 6.6 m there were four sleeves.

2.7.2 Pipeline Incident of 8 March 1976

IPL's Line No. 3 suffered a break on 8 March 1976, near KmP 121, approximately eight kilometres downstream of the Strome pump station. NEB staff investigated the causes of this break and prepared a report under NEB File No. G1795-J1 (May 1977). An internal IPL report, dated 12 May 1976, was also prepared.

In January 1974, IPL excavated the Line No. 3 pipeline in the vicinity of KmP 121 for maintenance purposes. Two sections of pipe, 11.6 m and 6.1 m in length, were removed and replaced with pipe manufactured in 1969. The repair pipes were joined to the remainder of the line using "weld + ends" couplings. The "weld + ends" were then fillet welded to the carrier pipe. As well, several full encirclement sleeves were installed in the same vicinity.

While no specific welding procedure had been established for fillet welding the coupling to the pipe, it was usual practice to perform the welds after the pipeline had been returned to service. The welds would have been performed with oil flowing under reduced pressure. A multi-pass welding technique was employed using cellulosic welding electrodes for the first passes, and low hydrogen electrodes for the final passes. Nondestructive testing of the fillet welds was not carried out, since IPL only began to perform such testing two years later, in 1976.

On 8 March 1976, Line No. 3 fractured immediately downstream of one of the "weld + ends" couplings at KmP 121. The carrier pipe involved in the break, was the 6.1 m long repair pipe that had been installed in 1974. Immediately upstream of the coupling were two full encirclement sleeves covering a combined length of 3.53 m (see Appendix VIII).

Examination of the fracture showed that failure initiated at a pre-existing hydrogen induced crack, present along the fillet weld toe for almost the complete length of the fracture. The crack had penetrated up to 35 percent of the carrier pipe wall and was likely formed soon after the fillet welds were made. The fracture was centred on the bottom of the pipe and had arrested at about the 9:30 and 2:30 o'clock positions. The HAZ of the final pass consisted of martensite and lower bainite, microstructures highly susceptible to hydrogen induced cracking.

The chemical and mechanical characteristics of the line pipe material involved in the failure were typical of a grade X52 semi-killed pipe steel manufactured prior to the early 1970's. The carbon equivalent was calculated to be 0.44 percent (see Table 2).

Propagation of the pre-existing crack was likely caused by bending stresses resulting from poor bearing support beneath this particularly heavy section of pipeline located within a slough area.

2.7.3 Similarities Between the Pipeline Failures of 19 February 1985, 23 February 1983, and 8 March 1976

1. Final pipe failure in each of the three incidents mentioned, resulted from the propagation of pre-existing hydrogen induced cracks, present within the heat affected zones of circumferential fillet welds. The cracks had been formed soon after the time the fillet welds were made;
2. The welds had been applied to join full encirclement devices to the carrier pipe. In each case, the welding was performed while the pipeline was liquid-filled and operating;
3. The presence of the hydrogen induced cracks was not detected at completion of the fillet welds. This was because either no post-weld nondestructive testing was performed, as in the case of the 19 February 1985 and 8 March 1976 incidents, or because the nondestructive testing was ineffective, as in the case of the 23 February 1983 incident;
4. In each case, the line pipe steel involved in the failure had a chemical composition which was typical of the grade X52 pipe manufactured prior to the early 1970's. This composition resulted in steel prone to the formation of high hardness martensite in the weld HAZ, a microstructure highly susceptible to hydrogen cracking;
5. Defect propagation and final failure occurred some time after completion of welding, when the stresses applied to the pipe exceeded a critical value. In each case, propagation initiated near the six o'clock position suggesting that the stresses resulted from downward bending of the pipe; and
6. Prior to each of the similar incidents, the failure area had been excavated and backfilled under winter conditions. Each of the breaks occurred within or near a slough.

2.8 Regulatory and Code Requirements

2.8.1 Regulatory Requirements Concerning Pipeline Maintenance Work

The NEB under its statutory powers has made the Oil Pipeline Regulations (Regulations). These Regulations were enacted on 28 September 1978. They are legally binding and apply to every company operating an oil pipeline under the Board's jurisdiction.

In addition to the requirements specifically prescribed by the Regulations, companies are bound, under subsection 3(2) of the Regulations, to comply with the CSA Standard Z183 "Oil Pipeline Transportation Systems" (CSA Z183).

With respect to pipeline maintenance and maintenance welding, the following requirements have been applicable to high vapour pressure pipelines since 28 September 1978:

1. Operating companies shall include in their manual of procedures governing the maintenance and repair of oil pipeline facilities, a welding procedure specification, qualified in accordance with clause 5.6 of CSA Z183;
2. Permanent pipeline repairs or removal of defects shall be in accordance with clauses 5 and 6.3 of CSA Z183, except where specifically prohibited in clauses 9.16.4.2 and 9.16.4.3;
3. All repairs and procedures shall be in accordance with API RP 1107, "Recommended Pipeline Maintenance Welding Practices", except that patching, puddle and lace welding shall be prohibited;
4. Removal or repair of weld defects shall be in accordance with one of the following:
   (a) cut out as a cylinder;
   (b) sealed off by the installation of a full encirclement welded split sleeve;
   or
   (c) in accordance with clause 5.10 of CSA Z183;
5. After the permanent repairs have been completed, the repairs shall be:
   (a) inspected for welding defects, in accordance with clause 6 of CSA Z183; or
   (b) retested to determine the maximum allowable operating pressure, in accordance with clause 7 of CSA Z183;

6. Use of saddles as permanent repairs to a pipeline is prohibited;
7. A company shall nondestructively test all permanent repair welds prior to resuming the operation of the pipeline;
8. Full encirclement devices used on a pipeline shall not be located closer than 12 m to each other;
9. The distance between the repair welds on a pipeline shall not be less than two pipe diameters; and
10. The repaired parts of pipeline facilities shall be properly supported, as set out in sections 12, 13 and 14 of the Regulations.

Prior to the introduction, in September 1978, of requirements specifically made by the Regulations, those numbered (6) through (10) above, were not in effect. Compliance with requirements (1) through (5), contained within CSA Z183 since the March 1973 edition, was voluntary prior to the implementation of the Regulations. CSA Z183, however, represented recommended good engineering practices, recognized by the petroleum industry.

2.8.2 Other Code and Regulatory Requirements

Several sections of both the Regulations and CSA Z183 deal with public and employee safety and the safe operation of pipelines, including those transporting NGL.

Section 99(1) of the Regulations states that: "In addition to the requirements set out in this Part and in CSA Z183 with respect to the operation, maintenance, repair, deactivation and abandonment of a pipeline, every company shall establish and maintain manuals and procedures applying to the company, its employees and its agents in operating, maintaining, repairing, deactivating and abandoning its pipeline."

Section 100 of the Regulations states, amongst other things, that: "The manuals referred to in subsection 99(1) shall adequately cover:

1. Emergency procedure information, such as:
   (i) personnel to be contacted in case of an emergency and their respective responsibilities,
   (ii) warnings to be given,
   (iii) types and locations of available equipment,
   (iv) safety precautions to be followed,
   (v) agencies to be contacted, etc."

Section I57(3) of the Regulations states that: "A company shall, in cooperation with the appropriate local authorities, formulate plans for evacuating people from the vicinity of the pipeline under emergency conditions."

Clause 9.12.1 of CSA ZI83 states that: "Personnel working with HVP materials shall be well informed of the physical characteristics and behaviour of such materials under all conditions likely to be encountered."

Clause 9.12.4 of CSA ZI83 states that: "Particular attention shall be given to surface terrain, direction and velocity of the wind, and the effects of vegetation and buildings when approaching a possible HVP leak. Immediate isolation from, or the elimination of, all possible sources of inadvertent ignition is essential. Combustible vapour detection shall be used when investigating and cleaning vapours from any hazardous area." This requirement is reflected in IPL's manuals.

Clause 9.4.1 of CSA Z183 states that: "Each Company shall maintain a periodic oil balance for system security."

Clause 9.4.2 of CSA Z183 states that: "Devices and procedures shall be sufficiently reliable for measurement of oil movement and early detection of leaks."

2.9 Company Manuals

IPL has written procedures, as required by sections 99 and 100 of the Regulations, for the operation, maintenance and repair of their pipeline system as well as for safe practices. These procedures were in effect at the time of the accident.

Section Seven of IPL's Operating and Maintenance Procedures Manual covers pipeline repairs for both planned and emergency work. Some of the requirements of this section are:

1. that all work equipment and tools be in good safe working condition;
2. that all ignition sources be kept out of hazardous areas;
3. that leak areas be explored using gas detectors;
4. that employees avoid being trapped by wind changes;
5. that work equipment be located considering high ground, wind direction, etc.;
6. that all employees be familiar with the characteristics of NGL;
7. that the best course of action for a major leak may be to flare the vapour cloud once the general area has been cleared of all personnel;

8. that prior to beginning the job the supervisor discuss with all workers the procedures to be followed, the method of repair, and the responsibilities of foreman and crew; and
9. that protection of the public takes priority over repair of the pipeline.

This manual is to be used in conjunction with IPL's Safety Manual. The Safety Manual includes sections on the following:

1. recognition of hazards;
2. ignition sources;
3. description and operation of safety and personal protective equipment; and
4. characteristics of products transported in the system.

These two manuals are accessible to all members of the Pipeline Maintenance (PLM) crew (maintenance crew). As revisions are made, they are sent to the maintenance crew foreman and inserted in the applicable manual. Contractors were not provided with these manuals prior to working on IPL's system.

2.10 Safety-Related Matters

Prior to the accident on 19 February 1985, IPL employed a Safety and Training Advisor to administer the company safety program and coordinate employee training. Specific duties included the distribution of safety material to field staff, the revision of the supervisor's safety check list and other manuals, and the preparation of reports for provincial and federal organizations. Once or twice a year the Safety and Training Advisor would conduct safety meetings or fire drills for field personnel at the maintenance locations.

It was not a general practice for this advisor to attend leak situations unless specifically requested. No such request was made for the incident of 19 February 1985.

Although the Safety and Training Advisor only conducted safety meetings once or twice a year, the maintenance crews did attend regular monthly safety meetings conducted by their foreman at their maintenance locations. At these meetings, discussions took place on sections of the safety manuals and safety problems encountered by the maintenance crew members. Demonstrations of certain types of safety equipment, such as fire extinguishers and breathing apparatus, also occurred during these hour-long meetings.

At the safety meeting of the Edmonton maintenance crew held on 18 February 1985 just prior to the accident, the hazards of NGL and the necessity of working safely in their vicinity were discussed.

Once every four months, a Joint Industrial Council consisting of company employees and company management meet to discuss wages, benefits, and subsidies as well as safety concerns not adequately dealt with at monthly safety meetings. One such issue, which had been raised, was that of safety clothing. Company employees on the Council were told that the Company would take this issue under advisement.

As part of the safety program for a new maintenance crew member, each supervisor had a safety check list itemizing hazards which could be encountered on the job. This list was to act as a reminder to the supervisor of safety concerns, such as breathing hazards, defective or mushroomed tools, fire and explosions, which he should cover with a new or transferred employee. Once the list had been covered, the supervisor would sign it, date it, fill in the employee's name and send it to Head Office. The employee would then be given a booklet entitled "Getting our Job Done Safely", which summarized some items covered by the check list. This process would be covered only once during an employee's term in a particular department. Should the employee be transferred to another department within the company, his new supervisor would review the safety check list emphasizing the hazards of the new job.

It was not company practice for any one maintenance crew member at a work site to be responsible for safe working practices. IPL maintained that the maintenance crew foreman had the primary responsibility for safety and that it was every employee's responsibility to observe safe working practices, as covered in the manuals. IPL also maintained that on-the-job training prepared employees to work safely and efficiently.

It was not IPL's policy to inform contractors, supplying equipment and operators, of the nature of the leak. Moreover, since these operators are under the direct supervision of company employees and do not work on their own, safety training was not provided for them.

Chapter 3
Analysis

3.1 The Accident

3.1.1 Review of Activities at the Accident Site

The evidence shows that IPL has made contingency plans for the evacuation of the general public in collaboration with emergency organizations in Edmonton, Regina and Sarnia. However, there are no similar plans for other populated areas. No evacuation of the general public was required as a result of the events of 19 February 1985.

The evidence demonstrates that upon arrival at the leak site the first concern of the IPL maintenance crew was to secure the work area from access by the public. The second concern was to assess the leak itself and the location of the vapour cloud. The site was successfully secured and the leak inspected.

The next step in the sequence of events was a determination of how to effect a repair. The matter was the subject of numerous discussions by radio between the field supervisors and the District Manager and by telephone between the District Manager and the Director of Operations (i.e. Messrs. Guthrie, Sartore, Sirois and Ross). After a first-hand inspection, Messrs. Guthrie and Sartore recommended flaring the gas before proceeding with the repair. Mr. Sirois was opposed to flaring the gas cloud. He favoured the installation of an upstream stopple first then a reassessment of the need to flare. On this matter of flaring, Mr. Ross indicated the men in the field had full permission to flare if they considered it necessary to do so. The evidence shows that Mr. Sirois did not relay to Mr. Ross the recommendation of Messrs. Sartore and Guthrie to flare the escaping NGL prior to installing a stopple. As well, Mr. Sirois did not communicate back, to Messrs. Sartore and Guthrie, Mr. Ross' full permission to flare the escaping gas if they considered it necessary to do so. The evidence shows that as a result, Messrs. Sartore and Guthrie were left with the impression that, unless they believed it to be 100 percent safe and they saw no other option as stated by Mr. Sirois, flaring the gas had been ruled out for the time being and a stopple should be installed. As a result, they were of the opinion that the decision with respect to flaring had been taken out of their hands.

The next step was to choose a stopple site. Mr. Sartore had discussed this matter of a stopple site with Mr. Sirois and they agreed the high ground to the northwest, as shown on profiles of the pipeline, was a relatively satisfactory location (see Appendix III). The final decision was left to the men in the field.

Shortly before the accident, Mr. Armstrong was instructed by Mr. Guthrie to take the line locating equipment and commence locating the three pipelines in the area. However, the unit was non-operational due to drained batteries.

Initially, the men at the leak site demonstrated an appreciation of the need to monitor the vapour cloud and in fact did so on a number of occasions. However, they did not show the same appreciation to monitor on a continuing basis.

Evidence presented at the inquiry shows that none of the men present at the time of the fire had ever received formal training in dealing with an NGL leak. Mr. Wack, who had brought two gas detectors to the site from Edmonton, had worked for IPL for four years. However, he did not know that one of the two detectors he was carrying was for the detection of hydrogen sulfide gases and would have been of no use for the detection of hydrocarbons.

The evidence indicates that the gases ignited at about 20:30 hrs. It had been dark for some time which would have made it very difficult if not impossible to visually observe the escaping hydrocarbon vapours. In any event, propane and butane vapours are essentially invisible under most circumstances. At the time of the ignition, there were a number of vehicles operating in the vicinity, so there were various possible ignition sources for the fire.

The evidence further indicates that the wind conditions and the location of the escaping gas were not being monitored on a continual basis. The evidence also indicates that the wind at Edmonton International Airport, some 75 kilometres westward, had shifted approximately 180° in direction during the period between 15:00 hrs. and the time of the fire. Changes in wind direction could probably have been detected had the men at the north and south barricades been continuously monitoring wind direction.

As noted previously, several sections of both the Regulations and CSA Z183 deal with public and employee safety and the safe operation of pipelines, including those transporting NGL. At the time of the accident, IPL did not comply with certain of these requirements.

Specifically, the evidence demonstrates that at the time of the accident, the Company had no formal requirement that maintenance crew members read and understand the Operating and Maintenance Procedures Manual or the Safety Manual. Crew members were expected to become familiar with the manuals on their own.

Although several members of the crew had read sections on their own initiative, the following points demonstrate that they did not fully grasp the hazards inherent in working around NGL:

1. the vicinity of the leak was not continually monitored for wind direction or NGL vapours;
2. vehicles at the leak site were left running, constituting potential ignition sources;
3. a lighting plant, with a history of starting problems, was brought to the leak site and boosted several times, potentially constituting another ignition source;
4. although several members of the Edmonton maintenance crew became aware of a strong smell of condensate in the area, as well as the appearance of ground fogs, they did not monitor for gaseous vapours using gas detectors nor did they evacuate the leak site;
5. the vicinity of the leak area was explored after dark using only a flashlight and without a gas detector;
6. they located the work equipment on low ground and failed to monitor the wind direction;
7. prior to beginning the job, the supervisor did not inform all workers of the procedures to be followed, the method of repair, and the responsibilities of the foreman and crew; and
8. additional gas detectors brought to the site were not used.

These points emphasize the fact that the Company did not comply with the requirements of clauses 9.12.1 and 9.12.4 of CSA Z183. These points further emphasize the fact that crew members did not have adequate safety training for NGL which would have sensitized them to the risks and dangers associated with the handling of propane and butane in an uncontrolled situation such as at a leak site.

In addition to not having a standard procedure to ensure that employees read and understand the manuals, the Company did not have a standard procedure for notifying employees, other than the foreman, of revisions to them.

At the time of the accident, the Company believed that contractor employees did not require training in IPL safety procedures since such employees were directly supervised by Company employees. However, on 19 February 1985, Mr. Froese of Kach Construction, though he had initially been met by Mr. Sartore, was not informed of the type of leak under investigation or to whom he should report. Upon arriving at the site he was not introduced to any IPL personnel nor was he notified of their responsibilities. In addition, he was not informed of the Company's safety practices or procedures. These omissions on the part of the Company are contrary to the requirements of clause 9.12.1 of CSA Z183.

The preceding combination of errors in judgement, failure to comply with code requirements, inadequate training and shifting atmospheric conditions contributed to a serious accident that killed two men and injured three others.

The Board is of the opinion that the actions of Company employees involved in this incident demonstrate a lack of understanding of the products involved and a lack of appreciation of the dangers and risks associated with an NGL leak.

3.1.2 *IPL's Review of the Accident*

Following the accident, IPL formed a Safety Task Force whose mandate was to investigate and make recommendations on the Company's overall procedures and the safety aspects of transporting petroleum products and, in particular, NGL. The Task Force achieved this by conducting meetings with field staff at all manned locations along the pipeline route and making recommendations based on comments received. As a result of this report, several changes were made to the IPL manuals. These changes include the following:

1. the use of wind socks at a repair site;
2. the need for continuous and/or frequent monitoring at a work site to determine hazardous areas;
3. the need to eliminate all ignition sources from such areas; and
4. the necessity of flaring an NGL leak once safety for the public has been determined.

IPL also decided to increase the number of safety and training personnel. The Company has maintained the position of Safety and Training Advisor and has created four new positions for Safety and Training Coordinators, two in Interprovincial and two in Lakehead. These Coordinators will report to the Division Managers.

The duties of the Safety and Training Advisor will essentially remain the same. However, he will now report to the Manager of Oil Measurement, Corrosion and Safety instead of the Manager of Employee Relations. The duties of the Safety and Training Coordinators will be to attend safety meetings on a quarterly basis, organize and assist at safety and training meetings, conduct audits and field inspections for compliance with company approved manuals, make safety and training suggestions and be present at planned work sites and major incident sites. Respecting safety at incident or work sites, should the Coordinator and foreman not agree on certain issues, there will be a work stoppage until safety concerns are resolved. The Coordinators will interface with the Advisor for coordination, guidance and direction on safety and training procedures.

IPL has recognized the need for employees to be more aware of the hazards of NGL and how to protect themselves when handling NGL. Consequently, employee attendance at flaring demonstrations, to be held every two years, will be mandatory. Records will be kept by the Coordinators to monitor such attendance. Regularly scheduled monthly safety meetings will systematically allocate time to NGL awareness training.

A systematic review of all IPL's operating manuals will be conducted at the safety meetings. Employees will also be encouraged to participate in the safety meetings by demonstrating safety equipment such as breathing apparatus and gas detectors. Consideration is also being given to having employees conduct part of these safety meetings, thereby familiarizing themselves with the subject matter.

New employees will be required to be familiar with safety manuals and operating procedures of the company before starting work and must successfully pass an examination on these manuals as a means of ensuring this familiarity. Such an examination will also be given periodically to existing employees to ensure that they maintain an awareness with the manuals. The Safety and Training Co-ordinator will maintain employee records on these examinations. New employees will also be required to sign the Supervisor's Safety Check list acknowledging that they have received instruction in areas listed. The instruction must be given and the list signed before the new employee assumes his duties.

IPL is in the process of preparing a pocket-sized personal safety manual to be distributed to each employee. A copy of this manual will also be issued for each Company vehicle. The manual will be comprised of extracts from the Company's manuals. A similar manual is being prepared for distribution to contractors prior to commencement of a job for IPL.

Each IPL employee will be issued a pair of Nomex coveralls which must be worn in leak situations and on work sites where there is a risk of fire. IPL has purchased spare Nomex clothing, to be located in the work trailer, for use by contractor employees or IPL employees should their clothing become damaged or soiled. The work trailer is to be on site prior to commencement of work.

IPL still maintains that supervisors are responsible for safe practices. However they will now be assisted by the Safety and Training Coordinators.

Other changes to safety procedures include:

1. additional portable radios for both the Eastern and Western Divisions;
2. radio receivers and transmitters for District Offices;
3. better utilization of local security agencies, police and/or RCMP to secure leak sites and alert near-by residents; and
4. the purchase of additional LEL gas detectors.

As a result of these actions, the Board is of the view that IPL's procedures now conform to the code requirements of clauses 9.12.1 and 9.12.4 of CSA Z183.

3.2 The Pipeline Break of 19 February 1985

3.2.1 Hydrogen Induced Cracking

Metallurgical investigation has indicated that the pre-existing defect which later propagated, resulting in the incident of 19 February 1985, was a hydrogen induced weld crack. Hydrogen induced weld cracking is also known as cold cracking, underbead cracking or delayed cracking.

The conditions which, when present simultaneously, can result in hydrogen cracking are well known. Cracking may occur only in the presence of:

1. sufficiently high levels of hydrogen;
2. sufficient levels of tensile stress; and
3. a hardened susceptible microstructure.

Further, hydrogen cracking will occur only once a weld has been allowed to cool substantially to a temperature of 150°C or lower. Hence the origin of the term "cold cracking". Absence of any of these aforementioned conditions will prevent the occurrence of hydrogen cracking.

3.2.2 Tensile Stresses and Hydrogen Cracking

Tensile stresses, contributing to the formation of cracks, are generated by thermal contraction of the weld on cooling. The level of these "residual" tensile stresses is greater when welding is performed on a rigid or highly restrained structure. Externally applied tensile stresses would be in addition to the residual stresses and would further increase the likelihood of hydrogen crack formation. Efforts can be made to control the total tensile stress acting on a weldment by ensuring that weld size, geometry, fit-up, yield strengths of the plate and weld metal are optimized. Nonetheless, a certain level of residual stress is always present following welding.

3.2.3 Hydrogen and Weld Cracking

During welding, hydrogen is absorbed by the weld from the arc atmosphere. During solidification and cooling the solubility of hydrogen in steel decreases and much of the hydrogen escapes by the process of diffusion. In most cases, however, weld cooling is too rapid to allow complete removal of hydrogen. The weld and HAZ may become supersaturated and prone to cracking as cooling progresses. Efforts to minimize the effect of hydrogen must seek to reduce the amount of hydrogen present in the arc atmosphere, as well as to favour its escape by diffusion from the weld and HAZ.

Hydrogen is formed under the intense heat of the welding arc through the decomposition of moisture and other hydrogenous compounds present in the welding electrode coating, and oil, grease, tar, rust, or other contamination of the workpiece. Reduction of the amount of hydrogen present therefore entails:

1. the use of welding consumables specifically formulated to contain a minimum of hydrogen producing compounds, i.e. low hydrogen welding electrodes;
2. the proper storage of the welding consumables to prevent deterioration, particularly through absorption of moisture; and
3. careful field practice to ensure that the area to be welded is adequately cleaned and protected from the elements.

The rate of diffusion of hydrogen through steel decreases rapidly as temperature falls. Techniques which result in a reduced rate of weld cooling allow a greater amount of hydrogen to diffuse and escape out of the weld deposit and HAZ, thus reducing the likelihood of cracking. Such techniques include:

1. application of pre and post weld heat; and
2. welding using increased heat input per unit length of weld.

Although weld hydrogen content may be reduced by these techniques, it cannot be totally eliminated. Even such a reduced hydrogen content may give rise to cracking, depending on the microstructure susceptibility and stress levels.

3.2.4 Microstructural Susceptibility to Cracking

Slowing the weld cooling rate, in addition to facilitating the diffusion and escape of hydrogen out of the weld, results in HAZ microstructures less susceptible to cracking. In general, the hardness of a weld HAZ determines its susceptibility to hydrogen induced crack formation. The microstructural changes which may result in hardening of the HAZ are in turn determined by the chemical composition of the parent metal and the rate of cooling experienced following welding. A high carbon content in steel, as well as high cooling rates, favours high HAZ hardnesses and high susceptibility to cracking. When welding upon existing structures or components, control of the cooling rate is the only means of influencing the as-welded HAZ hardness.

Hydrogen induced cracking may occur immediately after the weld has cooled to about ambient temperature or may occur after an incubation period, depending on the hydrogen content, stress levels and microstructure susceptibility. This has given rise to the term "delayed cracking" and is why final nondestructive examination is frequently performed only after a period of about 48 hours has elapsed following weld completion, in cases where a risk of hydrogen induced cracking exists.

3.3 IPL Sleeve Welding Practices and Hydrogen Induced Cracking

Oil pipeline companies are required by section 9.16.2 (a) of CSA Z183 to establish and qualify a welding procedure specification for pipeline maintenance purposes. Qualification of a welding procedure involves carrying out various tests stipulated by CSA Z183, the objective of which is to demonstrate that welds having suitable mechanical properties and soundness can be made by the procedure in question.

In 1973, IPL commissioned A. Murray MacLean and Associates Ltd., metallurgical consultants, to perform trial welding of a nipple and a sleeve to a liquid-filled pipe. This study compared the properties of welds made while the line content was static, while it was flowing, when pre-heat was applied, and when no pre-heat was applied. The report on this work concluded there was little hardening of the HAZ in any of the samples examined. It further concluded that welds made using no pre-heat and while the pipe content was flowing exhibited the most desirable HAZ microstructure.

The results reported in 1973 by MacLean essentially describe pipe steel having a very low tendency for HAZ hardening. This is in sharp contrast to the findings of the metallurgical investigations into the 19 February 1985, 23 February 1983, and 8 March 1976 failures. The MacLean report does not specify the chemical composition of the line pipe used for testing, nor does it provide details of the welding procedures used. Because of the sharp contrast between the findings of the MacLean report and the findings in respect of the above-referenced three breaks, one can only conclude that the weldability of the pipe used for the MacLean tests was not representative of the pipe involved in the three mentioned failures and perhaps of much of the IPL system installed prior to the early 1970's. If that indeed was the case, any reliance on the conclusions from the MacLean report, regarding the weldability of IPL's actual pipe, would have been inappropriate.

The welding procedure WP-2 had been established in writing by IPL for welding of full encirclement sleeves to the main line under flowing conditions. However, no testing, evaluation or qualification in accordance with clause 9.16.2 (a) of CSA Z183, was performed by IPL prior to the use of this procedure.

In addition to welding procedure WP-2 not having been adequately qualified, evidence indicates that at least one requirement of WP-2 was not respected during the installation of the sleeve at KmP 84.12. The fillet welds for that sleeve were deposited using a vertically downward progression rather than vertically upward. The characteristically higher travel speed of vertically downward welding results in a low heat input. Low heat input is unfavourable in terms of HAZ hardness as well as hydrogen escape.

Procedure WP-2 specifies the use of class E7018 low hydrogen welding electrodes. Metallurgical analysis was unable to confirm the class of electrode that had in fact been employed. However, IPL testified that low hydrogen electrodes were not used until at least two years after the installation of the sleeve at KmP 84.12 in July 1973.

Regarding control of weld hydrogen, testimony indicates that following the 23 February 1983 incident IPL put in place measures to preserve the quality of low hydrogen welding electrodes, including the use of holding ovens. When necessary, protection against inclement weather is provided and pipe surfaces are completely brushed clean prior to welding. Maintenance staff were alerted to the need to reduce hydrogen contamination of welds and were instructed in the precautions to take.

The usefulness of pre-heating or post-heating for the purpose of HAZ microstructure control is eliminated when welding on a liquid-filled pipe. Maintaining the pipe at an elevated temperature is not practicable due to the powerful heat sink of the line contents.

The welding heat input specified by procedure WP-2 was between 1.26 kJ/mm and 3.21 kJ/mm. However, since the direction of welding progression called for by WP-2 was not respected for the installation of the sleeve at KmP 84.12, the heat input stipulations of this welding procedure were likely not maintained.

The fillet weld which failed on 23 February 1983 was welded vertically up using welding procedure UF-04. A heat input of between 2.46 kJ/mm and 5.65 kJ/mm was specified for the final pass. Welding of the sleeve at KmP 84.12 in a vertically downward progression aggravated the potential for hydrogen crack formation. However, the susceptibility to cracking of this material is such that fillet welding performed vertically up also exhibited cracking.

Regarding the stresses involved in causing hydrogen induced cracking, the fillet welding of full encirclement sleeves to a pipeline is a configuration that affords few means to exercise significant control. The pipe being welded upon is rigidly restrained, so that a high level of residual stresses can be expected. Imperfections in weld bead contour, undercut, etc., could produce additional local stress intensification.

3.4 Nondestructive Testing

Oil pipeline companies are currently required by section 48 of the Regulations to nondestructively test all permanent pipeline repair welds. This regulation took effect in September 1978. Since 1976, IPL has been ultrasonically testing fillet welds on a regular basis. This was at times supplemented by another nondestructive testing technique referred to as magnetic particle inspection.

Magnetic particle inspection is a nondestructive testing method capable of detecting cracks which either break the surface or are located close to the surface. Defect length may be estimated but not depth.

Ultrasonic inspection is a sensitive nondestructive testing technique, well suited to the detection of planar defects such as cracks. Defect location within a specimen, as well as defect dimensions, can be estimated. The success of ultrasonic inspection is critically dependent on the skill and diligence of the operator, who is required to perform a variety of interpretative functions. Also of importance is the nature of the test equipment and its maintenance in proper calibration.

When selecting a method for nondestructive testing, it is the company's responsibility to consider the nature of defects that may result from the welding process employed as well as the capability of the test method to detect such defects. The company may require that testing personnel demonstrate the capability of the testing procedure to detect defects and the ability of the personnel to interpret properly the indications given.

The sleeve to pipe fillet welds that failed on 19 February 1985 and 8 March 1976 were performed prior to 1976 and had, therefore, not been nondestructively tested.

The fillet weld which failed on 23 February 1983 was performed on 9 February 1982. An ultrasonic testing report was issued eight days later indicating no defects were found. The 210 mm long x 3.7 mm deep crack, which later caused this line break, went undetected.

Since IPL began ultrasonically testing newly completed fillet welds, the repeatability of the testing results has been poor. Test records are available for 216 fillet welds which have been ultrasonically examined since 1977. Cracks were detected in 2.8 percent of the welds examined. In August 1985, as part of the IPL Line Integrity Task Force work, ultrasonic testing was repeated on 26 sleeve to pipe welds that had been originally inspected and passed or repaired upon installation in 1981 and 1982. Cracking was detected in 42 percent of the welds tested.

IPL has testified that a cause for the inconsistent ultrasonic testing results was the advancements made in testing techniques and operator training in the last two years. There has indeed been a continuing evolution in this field. Further, the Board recognizes that the detection of defects at the toe of fillet welds involves a significant degree of complexity. Nonetheless, by 1977, the year IPL began ultrasonically testing newly completed fillet welds, the technique had reached a level of maturity that should have allowed the detection of many of the cracks that were missed during the original inspections. Some of these cracks were large, such as the one which caused the 23 February 1983 break. Evidence indicates that the nondestructive inspections done for IPL from 1977 to 1985 were performed without the existence of a written company inspection procedure. It was therefore difficult for the company to assure inspection consistency. The capability of the testing procedures used to actually detect defects was not verified.

The ultrasonic and magnetic particle testing performed for the IPL Line Integrity Task Force phase I, was done using the procedures developed for this purpose by the Welding Institute of Canada. A very significant improvement in crack detection rate was noted. However, the number of cracks that still went undetected, as evidenced by laboratory investigations, plus the inability of the inspections to accurately estimate defect size, are causes for concern.

It must be emphasized that nondestructive testing is intended to give an indication of the integrity of welds that have been produced in accordance with adequate and qualified welding procedures. Only on that basis can there be a reasonable assurance that the required level of weld quality has been obtained.

3.5 Propagation of the Pre-existing Crack

Although the hydrogen induced weld cracks associated with the pipeline breaks of 19 February 1985, 23 February 1983, and 8 March 1976 were formed shortly after completion of sleeve to pipe fillet welds, final failure only occurred between one and eleven years later. In each case the pipeline fractured when the size of the pre-existing crack, in relation to the level of stress applied to the pipe at that point and the pipe mechanical properties, exceeded a critical value required for crack propagation.

Calculations related to the 19 February 1985 incident have shown that a stress corresponding to 0.2 percent strain was required to initiate propagation of the crack. This level of stress did not result from internal pipe pressure. In each of the three incidents, propagation initiated near the bottom of the pipe. Therefore it is likely that the necessary stresses resulted from downward bending of the pipeline.

Although causes for the downward pipe bending have not been conclusively determined, certain theories have been proposed. It is known that in the case of each of the incidents the pipe had been excavated at or near the fracture location under winter conditions prior to the failures. Freezing of the backfill material was likely to have occurred and backfilling was probably performed without particular attention for proper compaction. Subsequent thawing and consolidation of the backfill material may have left the pipe with reduced bearing support.

It has also been suggested, after the 19 February 1985 incident, that a frost heave mechanism may have been responsible for the downward pipe bending. This mechanism is said to be related to the location of each of the failed sleeve welds just inside the boundaries of a slough and to the failures having taken place in late winter, when ground frost penetration was near a maximum.

In the case of the 8 March 1976 failure, downward bending may have been associated with the weight of several "welds + ends" and full encirclement sleeves in the immediate vicinity. There is some metallurgical evidence to suggest that the crack associated with the 23 February 1983 incident may have grown slightly in service by metal fatigue prior to fracture.

3.6 Pipeline Reinforcement by Sleeving

3.6.1 Stress Sharing

When full encirclement sleeves are applied over non-leaking pipeline defects, they are capable of carrying a portion of the hoop stress that would otherwise be sustained entirely by the carrier pipe. The proportion of the hoop stress carried by the sleeve at operating pressure is a function of the line pressure at the time of sleeve installation as well as the sleeve strength and thickness relative to that of the carrier pipe. Any looseness in the fit of the sleeve over the carrier pipe results in lost stress sharing ability.

It has been demonstrated that an ideally fitted sleeve, with a wall thickness equal to that of the pipeline, installed with the line pressure reduced to 67 percent of the operating pressure would carry less than 17 percent of the total hoop stress. In addition, a perfectly tight fit is difficult to achieve in practice. Researchers have therefore concluded that in the case of non-preloaded sleeves installed over non-leaking line defects, much of the reinforcement imparted by the sleeve is due to effects other than stress sharing.

3.6.2 Restraint of Bulging

The areas surrounding line pipe defects bulge outwards significantly prior to failure under increasing pressure. Defects can be prevented from failing if this prior bulging is restrained. Research has found that most of the reinforcing effect of sleeves installed over non-leaking pipe defects is due to their restraint of defect bulging.

Provision of restraint is dependent on firm contact between the defective pipe surface and the sleeve. In order to make sleeve fitting less critical, a hardenable filler material may be applied between the pipe and sleeve. In cases where the carrier pipe is dented or out of round, use of a hardenable filler is mandatory if restraint of defect bulging is to be provided.

Since full encirclement sleeves installed over non-leaking defects provide reinforcement by restraining bulging, the sleeves need not be designed to contain pressure. Consequently, fillet welding the ends of the sleeve to the carrier pipe is not required for this purpose of bulge restraint. Indeed, welding of the sleeve to the pipeline is not desirable in view of the potential for the introduction of serious welding defects. Crevice corrosion between the pipe and sleeve can be prevented by a heavy layer of protective coating.

Full encirclement sleeves can be used as described in this section to repair certain kinds of non-leaking line pipe defects, including external corrosion pitting, dents and gouges. However, they should not be applied to repair defects in brittle ERW pipe seam welds.

3.6.3 Sleeving of Leaking Defects

Repair of leaking defects by sleeving requires the use of sleeves welded to the pipeline and capable of retaining pressure. Once the space between the sleeve and the carrier pipe is pressurized, the sleeve becomes the only stress-carrying element while the pipe beneath it is stress-relieved. The integrity of the sleeve and the soundness of the sleeve installation welds are therefore critical. Research, as well as field experience, have illustrated the potential for serious defects to arise within the sleeve installation welds.

3.6.4 Pre-stressed Sleeves

IPL is participating in the development of hydraulically pre-stressed sleeves for possible future use. This sleeve design is intended to increase the proportion of hoop stress carried by the sleeve and would involve no welding to the pipe body when installed over non-leaking defects.

Test results, submitted as evidence by IPL, appear to confirm the capability of the pre-stressed sleeve to share a portion of the hoop stress with the carrier pipe and the absence of welding on the carrier pipe would eliminate any potential for pipe failure due to welding defects. However, no evidence was submitted regarding the effectiveness of this sleeve in actually preventing failure of carrier pipe defects. Such effectiveness must be demonstrated prior to the adoption of this sleeve for field use.

3.6.5 IPL's Fillet Welding Development Program

Following the incident of 23 February 1983, IPL requested that the Welding Institute of Canada develop an optimum procedure for fillet-welding full encirclement sleeves to an operating oil pipeline. After some preliminary tests and discussions with IPL, the fillet-welding development program was undertaken.

Testimony indicates that the new IPL welding procedure UF-28-85/S* was established as a direct result of the development work undertaken by the Welding Institute of Canada.

Having recognized the limited effectiveness of preheating a liquid-filled pipe, the test work concentrated on reducing the susceptibility to cracking by considering the effect of the welding heat input and the weld bead configuration. The Board notes however that most of the welding trials were performed on pipe material that had significantly better weldability than the majority of pipe in IPL's system. Although welding procedure UF-28-85/S* was later qualified to CSA-Z183 using more representative pipe material, HAZ hardness, the prime indication of crack susceptibility, was not reported. Further, the weld bead configuration required by UF-28-85/S* is not one which was recommended by the Welding Institute of Canada. As well, the required heat input for the final two weld passes (0.98-1.47 and 1.48-1.95 kJ/mm respectively) is significantly lower than that recommended by the Welding Institute of Canada. The maximum HAZ hardness allowed by UF-28-85/S*, $400HV_{500}$, is one which may be susceptible to cracking if hydrogen and stress levels are not adequately controlled.

The Board is of the opinion that although the fillet welding development program and the establishment of the welding procedure UF-28-85/S* were positive steps, this welding procedure does not provide an adequate margin of safety for prevention of hydrogen cracking in view of the nature of much of the pipe in the IPL system and the inevitable variations in welding parameters associated with manual welding which arise under field conditions. The Board believes that welding on liquid-filled pipe should not be practiced except where required during emergency situations. Any welds, so performed in the future, should be considered as temporary to be removed from the pipeline as soon as possible.

3.6.6 IPL's Line Integrity Task Force

Shortly after the incident of 19 February 1985, IPL formed the line integrity task force. The objectives of the task force were:

1. to assess the condition of full encirclement sleeves on the pipeline system;
2. to evaluate the available methods of nondestructive testing;
3. to confirm the results of defect assessment calculations by full scale testing;
4. to study the origin of the forces leading to bending of the pipeline; and
5. to develop repair methods for fillet welds found to be defective.

The task force is carrying out its work in two phases. During phase I, sleeves on a recently abandoned segment of Line No. 1 in the immediate vicinity of the 19 February 1985 accident location were examined. A report on these activities was issued on 21 February 1986. During phase II, the task force is examining additional sleeves elsewhere on the system. Although phase II activities are ongoing, some preliminary results have been forwarded to the Board.

IPL has indicated that at least 1072 full encirclement sleeves have been welded to the carrier pipe of their pipeline system. Other devices, whose installation involved welding to the liquid-filled pipe, such as couplings, stopple tees, etc., are also present. These devices were installed under conditions and using methods essentially similar to those involved in the documented failures. Where composition of the line pipe resulted in a similar or greater crack susceptibility, as is the case for the major part of the IPL system, welds so performed could be expected to have a significant probability of containing cracks. Evidence confirming this expectation has been obtained through examination of intact sleeves from the IPL system by the Welding Institute of Canada, and by the IPL task force phase I which conducted field and laboratory ultrasonic and magnetic particle testing using procedures developed by the Welding Institute. Cracking was reported in 40 percent of the total of 42 fillet welds examined by these studies. A 53 percent incidence of weld cracks has been found in the first 68 welds examined by IPL's task force phase II.

Some of the fillet welds nondestructively examined under field conditions were later re-examined nondestructively at the Welding Institute of Canada laboratories. In 23 percent of these welds, cracks were found which had been missed by the field inspection. The existence of these cracks was also confirmed by sectioning of the welds. Their dimensions varied up to a length of 15 mm and a depth of 0.94 mm. In addition, several indications interpreted as being cracks by both field and laboratory inspections, were proven by sectioning to have been caused by other weld features. Due to the inability of nondestructive testing to detect fillet weld toe cracks with adequate certainty, the Board has concluded that welds having a demonstrated potential for containing cracks and located so that a failure would result in unacceptable risk to the public, must be treated as if cracking were present regardless of any nondestructive testing results.

Crack dimensions estimated by the field ultrasonic inspections, were verified by sectioning. It was found that the crack depths determined by ultrasonics in all cases underestimated the actual crack depth, sometimes by a considerable margin. The most extreme example was that of a crack estimated by ultrasonics to have a depth not exceeding 0.38 mm, and actually determined by sectioning to be 4.52 mm deep. The task force concluded that no adequate procedure had been found to nondestructively determine the depth of a fillet weld toe crack.

For the purposes of Engineering Critical Assessment (ECA), knowledge of flaw dimensions is required. In the absence of accurate flaw size information from nondestructive testing, the IPL task force proposed basing ECA calculations on the assumption that the cracks had penetrated through 33 percent of the pipe wall thickness. While this assumption may be conservative for the majority of the fillet weld toe cracks studied, each of the three failures described in this report were caused by cracks which had penetrated in excess of 33 percent of the wall thickness. One crack that had penetrated 57 percent of the pipe wall thickness was discovered by the present task force.

The potential for loads imposed on a pipeline to evolve over time has been demonstrated by the three IPL line breaks described in this report, one of which occurred over eleven years following formation of the crack. Acceptance of weld cracks based on current, site specific stress analysis, may not prevent future failure should loading conditions change.

In view of the uncertainties related to the detection and sizing of cracks by nondestructive methods, as well as possible evolution over time of pipeline stress conditions, a cautious approach is warranted. As a result, any weld containing a flaw interpreted as being a crack must be considered to be unacceptable regardless of the reported crack dimensions.

As a method of repair for fillet welds found to contain unacceptable weld cracks, the IPL task force has proposed the installation of two additional full encirclement sleeves so as to enclose the defective weld in a pressure tight container. This is not a repair method recommended by the applicable industry standards. The documentation submitted by IPL in support of its proposed repair technique was found by the Board not to be persuasive.

The Board considers that the most appropriate method of repair for weld cracks given the nature of the defect, is a cut-out of a cylindrical piece of pipe containing the defect, followed by the installation of a replacement pipe by butt welding. Techniques are available for effecting such repairs without the need to perform additional fillet welds.

The Welding Institute of Canada concluded in its report to the task force that the presence of long or multiple sleeves within a short length of pipeline would reduce pipe deflection but increase strain locally. Such increased strain would increase the likelihood of defect propagation should a defect be present. As a measure of good practice, the frequency of full encirclement devices installed on a pipeline should be limited, at least so as to respect a minimum spacing. Oil pipeline companies are required by section 116(4) of the Regulations not to install full encirclement devices closer than 12 m to one another. The evidence demonstrates that for the line breaks of 23 February 1983 and 19 February 1985 this was not the case. As well, evidence gathered at the hearing demonstrates that IPL has installed full encirclement devices closer than allowed under the Regulations for other locations on its pipeline system.

Should the condition of a company's pipeline require a more frequent installation of sleeves, this must only be carried out as a temporary measure before pipe replacement can be carried out. Consideration should also be given to the cause of the pipe damage, such as a malfunctioning cathodic protection system.

3.7 Operating Conditions Preceding the Break

3.7.1 Pipeline Control System

IPL has developed a Supervisory Control and Data Acquisition (SCADA) system which enables control room operators to monitor and control pipeline operations through the main computer. The operator's work area consists of a CRT screen for each line under his control together with operator command key boards. Each work station also has an extra screen for accessing computer programs and information to assist the operator.

Information, such as station pressures, pressure set points, calculated flow and status of pump units, appears on the CRT screen and is updated every 20 to 60 seconds, depending on the frequency with which the computer scans each station. This information is stored in the form of historical data in the computer bank in intervals of four minutes for the preceding four hours and can be retrieved by the operator.

A batch-tracking and material balance program, requiring operator input, forms part of the pipeline monitoring system. Every two hours, the program prints out the location of the batches as well as volume deviations between injection and delivery points. An unanticipated change in volume can indicate a system malfunction or produce loss. The batch-tracking program is usually used by the operations staff for scheduling flows as well as for leak detection.

The leak detection program was developed by IPL staff during the late 1970s. The program calculates flows between adjacent pump stations using data such as upstream station discharge pressure, downstream station suction pressure, physical characteristics of the pipeline section and batch location, and displays these flows continuously on the CRT screens.

Should a deviation in flows between any two adjacent stations reach a predetermined level set by the Company, a message indicating a suspected leak in that section will appear at the bottom of the CRT screen. In addition, an alarm will sound which the operator must acknowledge. If any irregularities in pipeline operations cannot be explained immediately, IPL has a standing procedure that operators are to shut the pipeline down first, followed by an investigation of the problem.

3.7.2 Pipeline Operations

Appendix VII provides a listing of the computer historicals of the pipeline operations on 19 February 1985 between the time period of 07:00 hrs. and 13:05 hrs. The Board notes that between 12:23 hrs. and 13:05 hrs. the computer historicals of the operations of IPL's Line No. 1 show that there were seven irregularities in operations:

1. the suction and case pressures at the Edmonton pump station dropped 67 and 111 psi, respectively, in 41 seconds;
2. both suction and case pressures at the Hardisty pump station dropped 94 psi in 19 seconds;
3. the calculated flow at the Edmonton pump station increased by 12 percent while that at Hardisty decreased by 50 percent;
4. the differential section pressure between the Edmonton and Hardisty pump stations varied between 450 and 560 psi while that between Hardisty and Kerrobert decreased from 904 to 162 psi;
5. five leak messages appeared on the operator's CRT screens accompanied by audible alarms;
6. stations downstream of Edmonton were throttling continuously on low suction; and
7. the 13:00 hrs batch-tracking printout showed a line volume loss of 579 m^3 since the last printout at 11:00 hrs.

According to Company procedure, the operators should have shut the line down when these line upset conditions began and then investigated the cause of the problems.

However, the operators believed that the conditions were in part due to the change in product stream and in part due to the lock-out of a pumping unit at Edmonton, and attempted to rectify the situation by compensating for it.

The first of the leak messages mentioned in point five above appeared on the CRT screen at 12:40 hrs, 17 minutes after the line upset conditions began. At that time, the calculated flow at Hardisty was approximately 35 percent less than that at Edmonton. Leak messages can appear occasionally during normal operations when the start-up or shut down of pumping units causes flow changes. During the first 17 minutes of the line upset conditions, changes in pumping units at Edmonton had occurred.

The CRT screens can accommodate only six messages at a time. As a new message appears, at the bottom of the CRT screen, the uppermost message disappears and cannot be recalled. Consequently, when the control room staff were attempting to analyze the line upset conditions, a record of messages was not available to assist them. If they had been able to see a record of all messages initiated since the line upset conditions had begun, they might have been able to recognize that a leak did exist between Edmonton and Hardisty.

The Company has stated that "IPL pipeline operators are well versed in basic hydraulics and each is adequately experienced with remote pipeline operation. Operators are trained for and accustomed to cause and effect type operation - meaning they are constantly reacting to line upset conditions". The Company also stated that "the operator's experience may enable him to suspect a leak due to continual downstream station throttling".

The Board notes that if pipeline hydraulic principles had been applied to the line upset conditions as mentioned in points one to four above, the operators might have been able to conclude that a line break had occurred in the pipeline section between Edmonton and Hardisty.

Moreover, the fact that the Hardisty and downstream stations were throttling on low suction for a period of time was also an indication of a line break upstream of that station.

The information mentioned in point six was not available to the operators while they were attempting to analyze the line upset conditions since it was only printed every two hours and had last been printed at 11:00 hrs. Had that information been available to the operators, it could have enabled them to identify the leak situation.

Though the Regulations and CSA Z183 do not contain specific requirements, the CPA suggested, in 1983, that material balancing information be made available hourly for high vapour pressure (HVP) pipelines in sparsely populated zone 1 locations and every five minutes for HVP pipelines in more densely populated zone 2 locations. IPL's line No. 1 goes through both types of zones yet their material balancing is only calculated every two hours. CPA suggestions are based on a consensus of the industry and are reflective of good industry practice. This particular suggestion regarding material balancing for HVP pipelines is indicative of the caution which must be exercised when dealing with NGL movements.

3.8 Training Programs for IPL Employees

3.8.1 Training of Pipeline Workers

According to IPL, on-the-job training is the most effective type of training for pipeline workers because of the specialized nature of the service and equipment involved. For certain types of equipment and supplies, this on-the-job training is supplemented by classroom and/or dealer instruction. IPL also feels that through this type of training employees are made aware of the hazards of materials transported by the company.

With respect to NGL, this type of training is supplemented by NGL flaring demonstrations, held every two years. The NGL demonstrations involve a controlled escape of NGL to the atmosphere and subsequent flaring of the gas cloud by either a flare launcher or pencil igniter. These demonstrations give the participants an opportunity to observe the behaviour of escaping NGL and the proper means of flaring. However, prior to the accident not all members of the Edmonton maintenance crew had attended such a demonstration.

The training in the use of other safety equipment, such as fire extinguishers and breathing apparatus, had been covered during the monthly safety meetings of the Edmonton maintenance crew. Training in the use of gas detectors and hydrogen sulphide detectors had not been given to all members of the Edmonton maintenance crew. It appears that those maintenance crew members who required such equipment for a specific job were shown how to use it prior to starting that job.

3.8.2 Pipeline Operator Training Programs

New pipeline operators undergo an on-the-job training program consisting of studying the Company's operations manual, a one day in-house session in pipeline hydraulics and observations of pipeline operations over a 12-month period. The operator trainee then operates the pipeline under close supervision of a more experienced operator over the next 24 months. In the event of a line upset situation, the more experienced operator would assume control of the pipeline system.

In the last two years the Company has purchased a computer simulation package which can provide computer simulation of pipeline operations. However, this form of training has been given only to the Company's more experienced operators and not to the operator trainees. Currently, the simulation package cannot simulate line break situation, although the package has this capacity if so programmed.

Chapter 4
Findings of the Board

4.1 Probable Cause of the Accident

The cause of the accident which resulted in fatal injuries to Messrs. Guthrie and Kelsey and severe burns to Messrs. Armstrong, Froese and Wack was the ignition of the escaping NGL gases. The Board determines that the cause of the release of NGL was the failure of a fillet weld on a full encirclement sleeve. The fillet weld failed due to a hydrogen induced crack. Ignition of the escaping NGL vapours occurred at or about 20:30 hrs.. A wind direction change of approximately 180° caused the NGL vapours to drift towards the site where the maintenance crew, preparing the site for repair, had left vehicles parked with the engines running. The accident might have been avoided had the pipeline repair crew flared the escaping NGL gas vapours or had they been located on higher ground further from the leak site and had the pipeline crew been equipped with and made use of additional lower explosive limit gas detectors and wind direction monitoring devices.

The Board concludes that the following factors contributed to the accident:

1. Failure to monitor the wind direction and the gas cloud on a continuous basis.
2. Lack of direct lines of communication between the men in the field and head office personnel, resulting in a misunderstanding with respect to the question of flaring.
3. A shortage of critical gas detection equipment to be used at the leak site. IPL maintenance crews were equipped with only two gas detectors per crew, one carried by the foreman and the other carried in the welding truck.
4. Failure of on-site personnel to react to the danger signals, probably because of insufficient training and knowledge of IPL's Safety and Operations and Maintenance manuals as well as a lack of experience in dealing with this type of situation.
5. Locating the work site for repair personnel too close to the leak location.
6. Requiring the maintenance crew to continue to work after dusk in the vicinity of NGL vapours which had not been flared.
7. Selection of a work site for the purposes of installing a stopple valve only 220 m upstream of the leak and at approximately the same elevation as the leak, instead of moving to a higher elevation further upstream.
8. The failure to instruct personnel at the site as to the plan to deal with this leak situation, the hazards involved and the role that each person was expected to play.
9. The lack of an emergency response plan to respond to NGL leaks in a systematic and organized fashion.
10. Lack of knowledge and understanding of the differences between an NGL leak compared to an oil leak.
11. Failure to conform to the code requirements of clauses 9.12.1 and 9.12.4 of CSA Z183.

4.2 Specific Issues

4.2.1 Metallurgical Cause for the Pipeline Break

The Board determines that the 19 February 1985 IPL Line No. 1 break, occurred due to the sudden propagation of a pre-existing weld defect. The defect was a hydrogen induced crack located in the HAZ of a fillet weld. The fillet weld had been applied to join a full encirclement sleeve to the carrier pipe wall.

The Board concludes that the following factors contributed to the pre-existing weld defect and its propagation:

1. The hydrogen induced weld crack was caused by the application of the fillet weld in a manner not suited to the materials and conditions at hand:
   (a) The carrier pipe material had a high carbon and carbon equivalent content, typical of grade X52 line pipe steel manufactured

prior to the early 1970's. This chemical composition favoured the formation of a hardened martensitic microstructure in the weld HAZ. Such a microstructure was highly susceptible to hydrogen induced crack formation.

(b) The sleeve to pipe fillet weld was performed while the carrier pipe was liquid-filled. The heat sink of the line content increased the weld cooling rate. In addition, it made the use of pre-heating for weld cooling rate control impracticable.

(c) The fillet weld was performed in a vertically downward progression and without the use of low hydrogen welding consumables. This was in violation of the then existing IPL welding procedure WP-2 and further favoured the formation of hydrogen induced weld cracks.

2. The likelihood of producing serious defects when welding under the conditions described under (1) had not been recognized by IPL:

(a) No testing or evaluation of WP-2 was performed prior to its use in the field. The welding procedure qualification tests required by CSA Z183 had not been performed.

(b) Welding trials commissioned by IPL in 1973 reported that welding on a grade X52 pipe, which was liquid-filled and its contents flowing, resulted in no HAZ hardening. This reported behaviour however was not representative of that observed in the case of the fillet weld fracture of 19 February 1985. Further, it was likely not representative of much of the IPL system installed prior to the early 1970's.

3. The weld crack which propagated causing the 19 February 1985 incident was formed soon after welding had been completed, likely within 48 hours. The presence of this crack was not detected, however, since nondestructive testing of the completed weld was not performed.

4. Propagation of the pre-existing crack and pipe failure occurred over eleven years after completion of welding. Propagation initiated when tensile stresses experienced by the pipeline at the defect location, in relation to the crack size and pipe mechanical properties, exceeded a critical value.

5. The tensile stresses contributing to the failure were likely the result of downward bending of the pipeline. Bearing support may have decreased because of consolidation of previously frozen, poorly compacted, backfill material or due to frost heave or both.

4.2.2 Supervisory Control and Leak Detection System

Based on an analysis of the information submitted during the inquiry, the Board has determined that the line break occurred at or about 12:23 hrs. on 19 February 1985. The Board finds in this incident that there existed a marked difference between actions of the Company's operation staff and stated policies.

The Board concludes that the following factors contributed to the excessive length of time which elapsed between the occurrence of the break and the line shutdown:

1. The operator's failure to follow Company procedure in the event of an unexplainable line upset condition.

2. Inadequate training of operators in pipeline operations and pipeline hydraulics.

3. A SCADA and leak detection system which does not provide for:

   (i) retention of comprehensive historical data and computer-initiated leak messages,

   (ii) early indication of a leak condition, and

   (iii) more frequent access to material balance and batch-tracking information.

Chapter 5
Recommendations

A key purpose of the Inquiry was to permit the Board to determine whether any changes should be made either in the way IPL operates or in the way IPL is regulated by the Board, in order to prevent similar accidents in the future. The opening statement of the Public Inquiry indicated that, depending on the evidence, the Board might find it necessary to use its powers under Section 39 of the National Energy Board Act either to order the Company to make changes to its pipeline, or to make changes to the Regulations under the NEB Act governing the construction and operation of the pipeline. The Board also wanted to determine whether there had been any breach of the NEB Act or existing Oil Pipeline Regulations that could have contributed to the accident.

In addressing the question of whether changes are needed in the Board's Regulations, the Inquiry Panel has taken into account that the Board has recommended substantial changes to the Oil Pipeline Regulations during the past year. They have been consolidated with the Gas Pipeline Regulations and have been renamed the Onshore Pipeline Regulations. They are currently being reviewed by the federal Department of Justice prior to Governor in Council approval. Some of the changes recommended by the Inquiry Panel have already been incorporated in the draft Onshore Pipeline Regulations. Other changes recommended by the Panel are not reflected in the draft Onshore Pipeline Regulations and would require further amendments to those draft Regulations. In the following sections, the Report distinguishes between these two different classes of changes in the Regulations.

5.1 Emergency Procedures Manual

To ensure that a consistent approach to accident responses exists with respect to pipelines under the Board's jurisdiction, the Inquiry Panel recommends to the Board that companies be required to have an Emergency Procedures Manual which deals with pipeline leaks and breaks. This Manual should include a requirement that two emergency exercises would be held by the Company each year. The Inquiry Panel notes this recommendation will not require an amendment to the Board's proposed Onshore Pipeline Regulations provided they are enacted as proposed.

The Emergency Procedures Manual for pipelines transporting hydrocarbons in the liquid state should be subdivided into three sections as follows:

1. General Emergency Response Information;
2. Oil Spill Contingency Plan; and
3. NGL and Other Volatile Materials Break Contingency Plan.

The Inquiry Panel recommends that a similar Manual should also be developed for pipelines transporting gaseous hydrocarbons under the Board's jurisdiction.

Section One of the proposed Emergency Procedures Manual should provide information which is common to emergency situations involving the various kinds of hydrocarbons transported in the liquid state and should contain, among other things, details on such items as:

1. organizational reporting structure for administrative and operating personnel;
2. responsibilities of the Safety Officer and his alternate;
3. responsibilities of key company individuals;
4. a list by location of available company individuals, other than those normally involved in a response, who can be called upon;
5. a list by location of company employees, together with job title and job functions, who maintain contacts with other emergency organizations;
6. a statement of the scope of application of the Emergency Procedures information;
7. emergency practice drills and their frequency;
8. provisions for lines of direct communication between the incident site and key individuals at head office;
9. a list by location of other emergency organizations together with details on the availability of persons and equipment; and

10. a listing by location of the quantities of emergency clothing and specialized equipment other than construction-related equipment; and

11. the program and schedule for maintaining all types of safety equipment and the identity of those responsible for ensuring adherence to this program.

Section Two of the proposed Emergency Procedures Manual should provide all information on a company's plans and procedures which would be specific to an emergency involving crude oil and equivalent hydrocarbons.

Section Three of the proposed Emergency Procedures Manual should provide all information on a company's plans and procedures which would be specific to an emergency involving liquid hydrocarbons which have a high vapour pressure. Hydrocarbons covered by this section of the proposed Manual would include propane, butane, pentanes plus, ethylenes, ethanes, gasolines, jet fuels, condensate blends and spiked crude oils. This section should include, among other things, details on such items as:

1. a list of qualified contractors together with an outline of available men and equipment;
2. volatile products emergency response plan emphasizing the different behaviour of volatile products versus crude oil;
3. procedures for the establishment of a repair site;
4. check list of critical site equipment and clothing;
5. a list by location of all specialized construction equipment;
6. limitations of specialty equipment used when responding to a volatile products line break; and
7. welding procedures and repair techniques unique to line breaks involving hazardous products.

The Inquiry Panel recommends that companies be required to ensure that the Emergency Procedures Manual contemplated in the proposed Onshore Pipeline Regulations, if adopted, embody the features recommended in this section. The Board may require that the Manual or portions thereof be submitted for approval.

5.2 Company Procedures Manual

To ensure consistency among all companies under the Board's jurisdiction with respect to pipeline operations and maintenance and safety activities, the Inquiry Panel recommends to the Board that companies be required to have an Operations and Maintenance Manual which reflects an emphasis on safety and protection of company employees and the public. The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would cover this recommendation.

This Manual should satisfy the following objectives:

1. that they provide clear and concise procedures for all activities and that they differentiate between crude oil and other volatile products;
2. that each manual be self-contained with little or no cross-referencing to other manuals; and
3. that the Maintenance Manual clearly distinguish between routine and emergency maintenance activities.

The Inquiry Panel recommends that companies be required to ensure that the Operations and Maintenance Manual contemplated in the proposed Onshore Pipeline Regulations, if adopted, embody the objectives contained in this section. The Board may require that the Manual or portions thereof be submitted for approval.

5.3 Safety Watch

To ensure a consistent approach to safety among all companies under the Board's jurisdiction, the Inquiry Panel recommends to the Board that companies be required to designate one safety watch per maintenance crew. The safety watch would ensure that safe procedures and practices detailed in company manuals are being followed by each maintenance crew. The safety watch would be a member of the maintenance crew but would not be the foreman or a company Safety Officer. To ensure that the designated safety watches have the necessary qualifications and to ensure a consistent approach to qualifying an individual as a safety watch throughout the Board's jurisdiction, the Inquiry Panel recommends that all safety watches be trained before working on a job site and that this information be included in the Emergency Procedures Manual referred to in section 5.1 of this report.

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would not fully cover this recommendation. A revision would be required in order to expand the application of the construction safety practices section in the proposed Onshore Pipeline Regulations to include company employees.

5.4 Safety Audits

As part of the systematic monitoring program required pursuant to subsection 155(1) of the existing Oil Pipeline Regulations, the Inquiry Panel recommends to the Board that all companies under the Board's jurisdiction operating high vapour pressure pipelines be required, by Board Order, to perform two safety audits, within three months of the issuance of such Order. The first safety audit would review the company's plans, procedures and equipment utilized when responding to an emergency situation. A second safety audit would be conducted for normal operations and maintenance activities. Companies would be required to submit a report of both safety audits to the Board as outlined in this part.

To ensure a consistent and enhanced emphasis on safety among all companies under the Board's jurisdiction, the Inquiry Panel recommends that the proposed Onshore Pipeline Regulations be amended to include a provision similar to that contained in section 155 of the existing Regulations. This section requires companies to submit a systematic monitoring program of current information on the pipeline for Board approval and implement remedial action if necessary.

As part of these requirements, companies would be obliged to engage the services of an independent company to perform the safety audits and file a detailed report with the Board. The report would address the positive and negative aspects of the company's activities and make recommendations for any necessary changes. Companies would be required to submit a timetable for implementation of any recommendations.

5.5 Training

To ensure a consistent approach to the training of pipeline operators and maintenance crew members among all companies under the Board's jurisdiction, the Inquiry Panel recommends to the Board that companies be required to provide the Board with an annual report outlining their policies and goals and the various types of training provided to employees. The report should contain an outline of the contents of each course and the number of employees who received training in the various courses together with short, medium and long term goals for the employees and the company. As well, the report should detail the safety training, if any, provided by the company to its contractors and sub-contractors who do contract work for the company.

During the inquiry IPL indicated that testing of employees who had reviewed the various manuals and safety devices would be instituted shortly. However, the Inquiry Panel notes that testing alone, under classroom conditions, may not accomplish stated corporate goals. Systematic dry-run exercises of various aspects of the manuals and equipment, when coupled with systematic classroom sessions and testing, would contribute significantly towards attaining stated corporate goals. The annual reporting of training information would demonstrate attainment of these goals.

The Inquiry Panel notes that the Board's Onshore Pipeline Regulations, if enacted in their proposed format, would cover this recommendation. The Inquiry Panel recommends that companies be required to ensure that the Training Manuals contemplated in the proposed Onshore Pipeline Regulations, if adopted, embody the features recommended in this section. The Board may require that the Manual or portions thereof be submitted for approval.

5.6 Welding Procedures

To ensure consistency among all companies under the Board's jurisdiction with respect to weld integrity, the Inquiry Panel recommends to the Board that companies be required to submit all new welding procedure specifications, accompanied by their supporting qualification test records, to the Board for approval. Approval would be granted if, in the Board's opinion, the capability of the procedure to produce sound welds was adequately demonstrated. The applicable stipulations of the CSA would be considered as a minimum requirement, to be exceeded if circumstances warrant.

The Inquiry Panel recommends that the Board select a date beyond which all pipeline construction and maintenance welding would be required to be covered by an applicable, Board-approved, welding procedure specification. During the interim period, companies could seek approval for existing welding procedures by submitting supporting documentation to the Board.

The Inquiry Panel recommends that the Board indicate its approval of a welding procedure specification by stamping the procedure document, as well as by way of a letter to the company. The stamping of welding procedures would serve to facilitate field inspections by the Board's staff.

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would not cover the submission of welding procedures for Board approval since they contain a subsection exempting the procedures from Board approval if the CSA standards are followed. Therefore, the Inquiry Panel recommends that the proposed Onshore Pipeline Regulations be revised to delete this exempting provision.

5.7 Non-destructive Testing Procedures

The Board's existing Oil Pipeline Regulations require that specified pipeline construction and maintenance welds be non-destructively tested. To ensure that a minimum level of effectiveness of the non-destructive testing is performed within the Board's jurisdiction, the Inquiry Panel recommends to the Board that companies be required to:

(a) formulate in writing non-destructive testing procedures to cover each testing application, including a statement of the minimum qualifications demanded of the testing personnel;

(b) perform the necessary evaluations to demonstrate the capability of the testing procedure to detect weld imperfections that may result from the welding process employed; and

(c) submit the testing procedure and supporting evaluation results to the Board for approval. The granting of the Board's approval would be signified by stamping of the procedure document and by way of a letter to the company.

The Inquiry Panel recommends to the Board that, after inauguration of the Board's non-destructive testing procedure approval mechanism, companies be allowed a grace period during which procedures could be formulated and the required approvals obtained. On expiration of this period, all non-destructive testing of pipeline welds required by the Board would need to be performed in accordance with an applicable Board-approved testing procedure.

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would cover the recommendation contained in (a) above. However, a revision would be required to implement the recommendations contained in (b) and (c) above.

5.8 Future Line Maintenance

The Inquiry Panel recommends to the Board that companies immediately discontinue the installation of full encirclement sleeves welded to the carrier pipe, for the repair of non-leaking pipeline defects.

For the repair of non-leaking pipeline gouges, dents, corrosion pitting, etc., the Inquiry Panel recommends that the use of full encirclement sleeves not welded to the pipe body, in combination with hardenable filler material, be permissible. Other sleeve designs may be permissible provided they are proven to provide effective defect reinforcement and do not involve welding to the pipe body.

The Inquiry Panel recommends to the Board that welding on liquid-filled pipelines not be practiced unless made necessary by emergency situations such as line breaks, or in cases where specific authorization has been obtained in advance from the Board. It is recommended that welds so performed be considered only as temporary repairs and be removed within 12 months from the date of installation, unless otherwise authorized by the Board.

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would not cover these recommendations. The Inquiry Panel recommends that the proposed Regulations be revised in order to implement these recommendations.

5.9 Integrity of Existing Pipelines

1. The Inquiry Panel recommends to the Board that all companies under the Board's jurisdiction, having performed any welding on liquid-filled pipe manufactured on or before 1970, be required by Board order to formulate a program and schedule for the removal of any such welds in Zone 1 and 2 locations on HVP pipelines and in locations which meet the requirements of Zone 2 on crude oil pipelines. The Inquiry Panel recommends that the Board require each company to seek and obtain Board approval for the program and schedule prior to its execution.

2. The Inquiry Panel recommends to the Board that all companies under the Board's jurisdiction, having performed any welds on liquid-filled pipe manufactured on or before 1970, in any location other than that specified in (1), be required by Board order to formulate a program and schedule for uncovering and non-destructively testing each such weld for cracking. The Inquiry Panel recommends that the Board require each company to seek and obtain Board approval for the program and schedule prior to execution. In lieu of non-destructive testing, a company may opt for removal of any welds performed on liquid-filled pipe manufactured on or before 1970.

3. The Inquiry Panel recommends to the Board that all companies under the Board's jurisdiction having performed welds on liquid-filled pipe manufactured after 1970, be required by Board order to uncover and non-destructively test a representative sampling of such welds for cracks. Companies would be required to report the results along with proposals for further action, if any, to the Board for approval.

4. For the purposes of the non-destructive testing in (2) and (3) above, the Inquiry Panel recommends to the Board that any weld flaw interpreted as a crack, regardless of dimensions, result in the rejection of the weld.

5. The Inquiry Panel recommends to the Board that any welds whose removal is required under (1) or (2) above, or which are rejected as a result of the non-destructive testing in (2) and (3), be removed by cutting out a cylindrical piece of pipe containing the defect and replacing it by butt welding in a section of pretested pipe that meets the design requirements. Companies should be required to take the necessary measures to perform such cut-outs without the application of new fillet welds to the pipeline.

5.10 Cathodic Protection

During the investigation into this accident, IPL stated that, in most cases, full encirclement sleeves were installed due to surface anomalies such as surface corrosion and in most cases when 60 percent of the pipe wall thickness had been removed. IPL, like other pipeline companies, had originally surface-coated the pipe and installed a cathodic protection system. With time, there has been a deterioration in the pipe coating, thus accelerating the corrosion problem and decreasing the effectiveness of the cathodic protection system.

To ensure uniformity among all companies under the Board's jurisdiction with respect to cathodic protection and surface coating matters, the Inquiry Panel recommends to the Board that companies be required to perform an internal survey of its pipeline system for internal and external corrosion and other surface anomalies on a regular basis as specified by the CSA. If this internal survey detects a zone of corrosion-damaged line, the company should be required to determine the cause(s) of the accelerated corrosion and formulate a plan, for Board approval, which would outline the corrective action the company will take to eliminate the cause of the problem.

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would cover this recommendation.

5.11 Cracks in Welds

The question of whether cracks in welds are permitted or prohibited by existing codes and Regulations has been the subject of some discussion.

To ensure that a consistent approach to treating cracks in any welds is followed by companies under the Board's jurisdiction, the Inquiry Panel recommends to the Board that no cracks be allowed in a weld and if a crack is found, the weld be removed as a cylinder.

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would not cover this recommendation. The Inquiry Panel recommends that the proposed Regulations be revised in order to implement this recommendation.

5.12 Supervisory Control and Data Acquisition (SCADA) and Leak Detection Systems

The CSA Z183 requires that all oil pipeline companies "maintain a periodic oil balance for system security", that "communication facilities shall be adequate to meet the requirements for safe pipeline operation ...", and that "devices and procedures shall be sufficiently reliable for measurement of oil movement and early detection of leaks".

To ensure that an adequate minimum standard for SCADA and leak detection systems exists with respect to pipelines under the Board's jurisdiction, the Inquiry Panel recommends to the Board that companies be required to:

1. have a pipeline computer Control Operations Manual which would include a detailed description of the following:
   (a) the SCADA system;
   (b) the communication facilities for pipeline operation;
   (c) the material balance system for oil and high vapour pressure pipelines together with an outline and justification of the various system parameters;
   (d) the leak detection system, including details of the capability and performance of this system under normal and line upset situations; and
   (e) the pipeline control operator training program;
2. file the results of an annual facilities audit, in the form of a report, of its SCADA system which would address the following:
   (a) details of pipeline shut-downs and their causes;
   (b) details of communication failures;
   (c) analysis of deficiencies identified in its pipeline control system including:
      (i) the SCADA system,
      (ii) the leak detection system, and
      (iii) the communication, batch tracking and material balance system; and

(d) the proposed program to rectify any deficiencies identified in (c) together with the schedule and costs;

3. incorporate in its pipeline control system the following:

   (a) an ability for the main control computer to keep track of detailed historical pipeline operations data, messages and alarms so as to be readily accessible to the operations staff;

   (b) a computer-initiated automatic shut-down system for the pipeline which would react within ten minutes when a leak situation has not been responded to by the pipeline operations staff;

   (c) a leak detection system reflective of the level of complexity of the pipeline system; and

   (d) a material balance system which is reflective of the level of complexity of its operations while at the same time meeting good industrial practices outlined by the CPA for liquid hydrocarbons pipelines; and

4. submit to the Board a detailed report outlining the current status and anticipated changes together with a schedule and costs for item (3).

The Inquiry Panel notes that the Board's proposed Onshore Pipeline Regulations, if enacted in their proposed format, would not cover this recommendation. The Inquiry Panel recommends that the proposed Regulations be revised in order to implement this recommendation.

The foregoing constitutes the Findings and Recommendations in the matter of this Inquiry pursuant to sections 20 and 39 of the National Energy Board Act.

J.R. Jenkins
Presiding Member

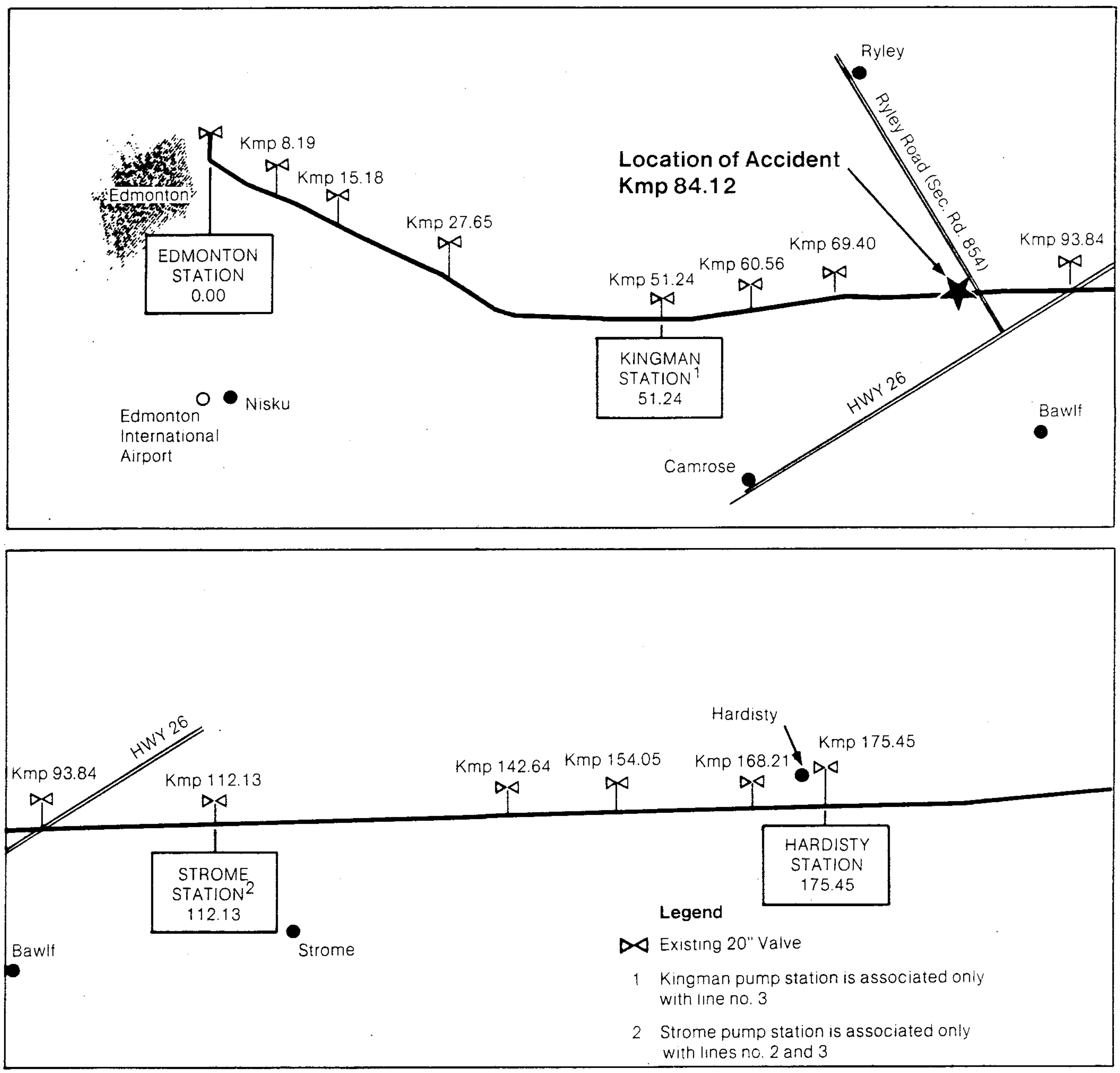
J. Farmer
Member

A.B. Gilmour
Member

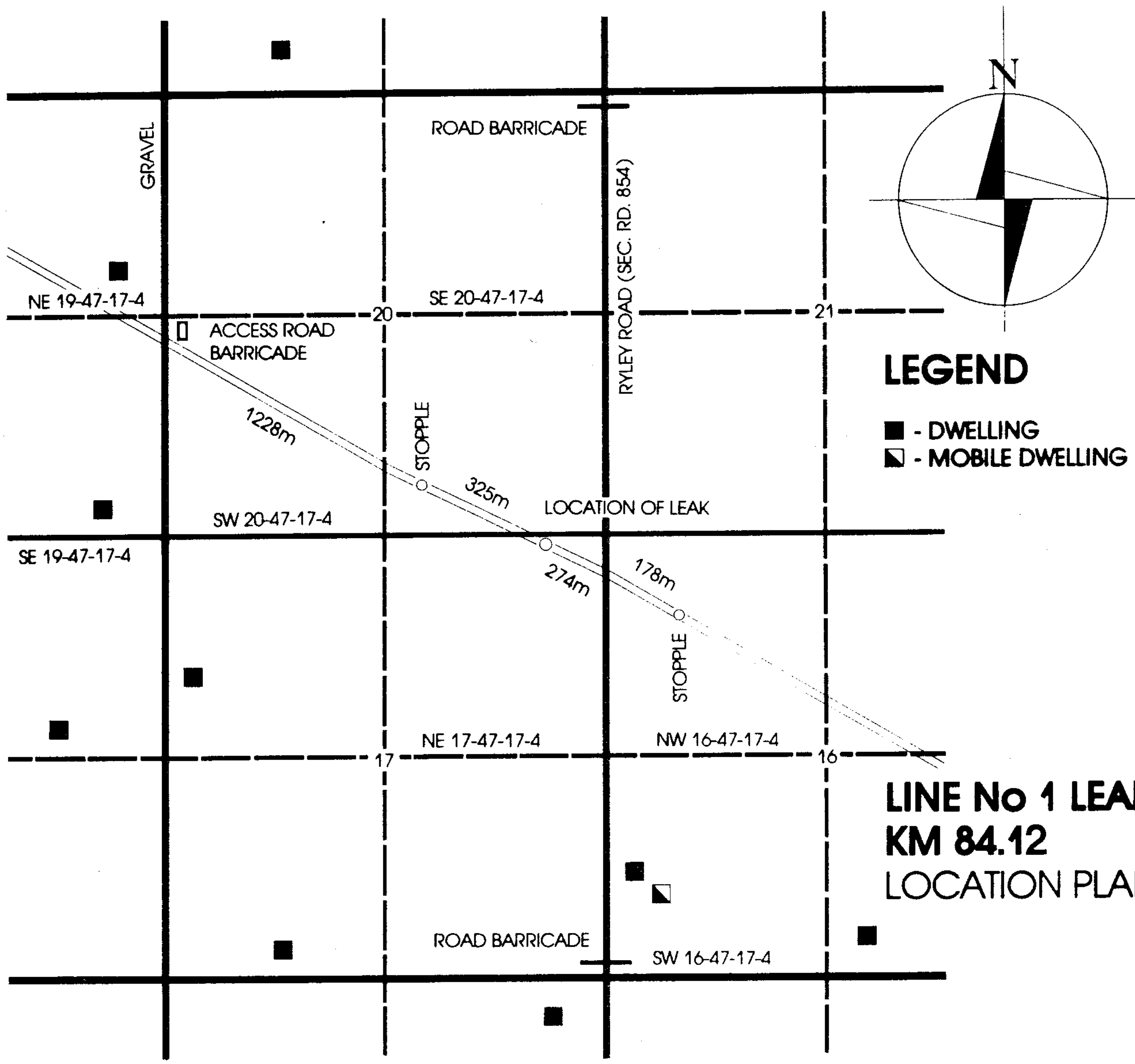
Ottawa, Canada
June 1986

Appendix I

Interprovincial Pipe Line Limited Valve Map — Line No. 1 — Edmonton to Hardisty Alberta

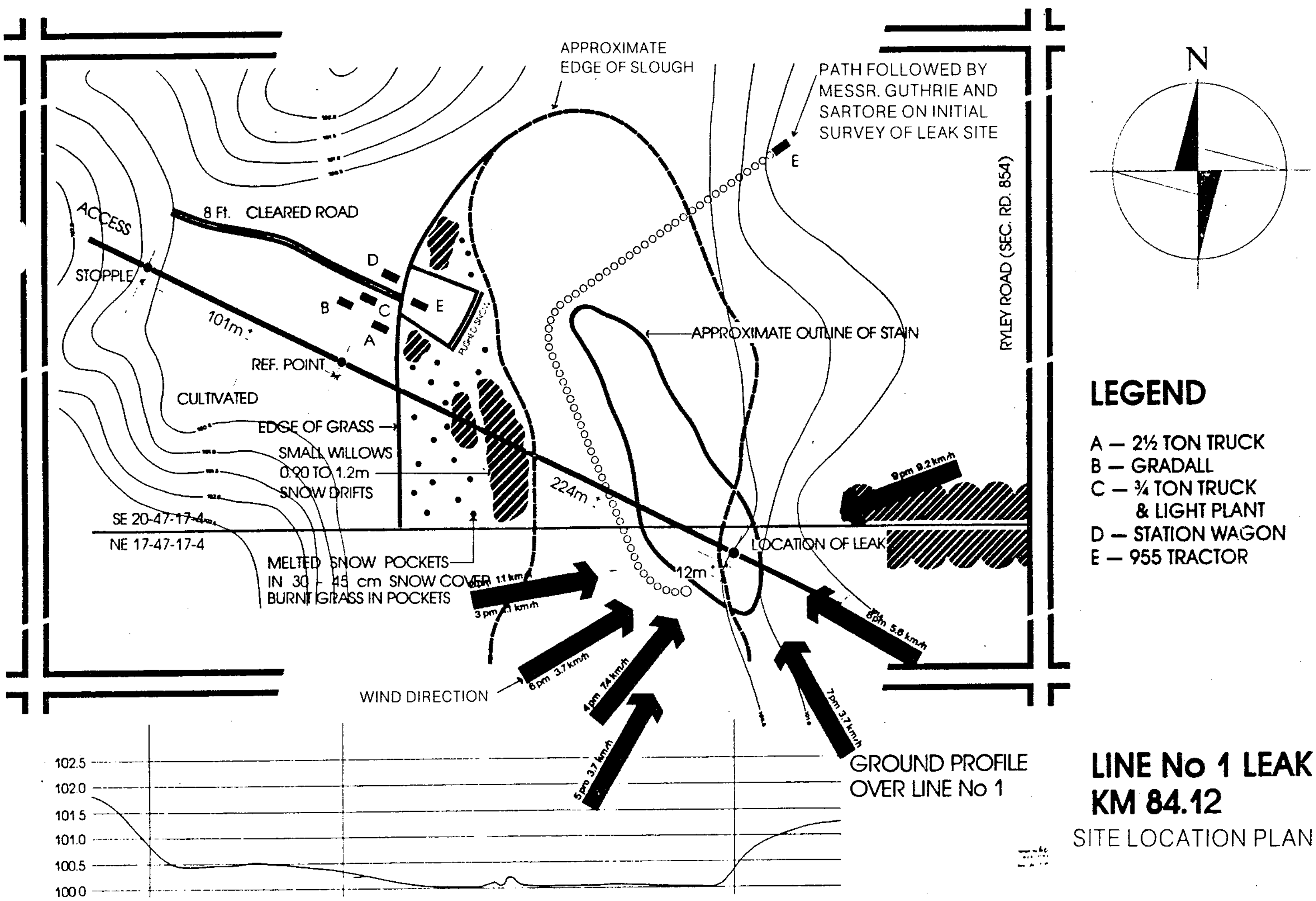


Appendix II

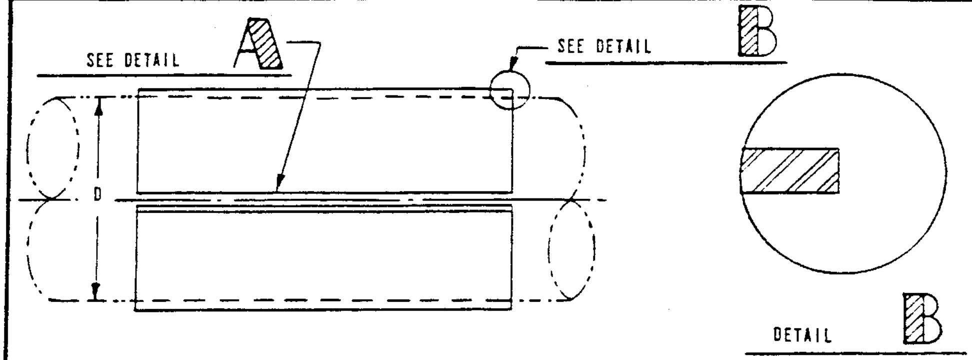


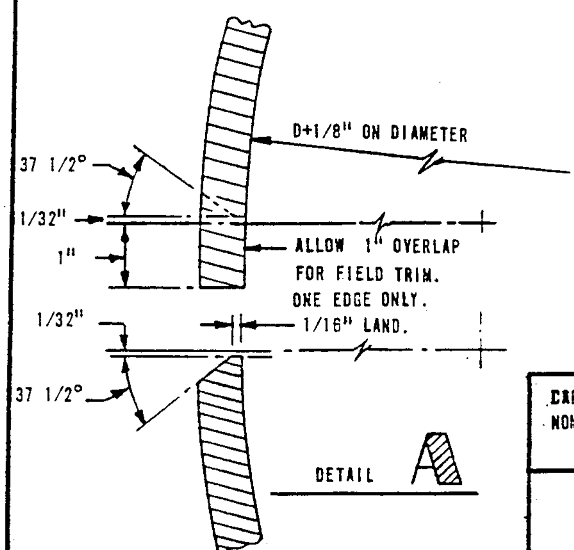
LINE No 1 LEAK
KM 84.12
LOCATION PLAN

Appendix III



Appendix IV



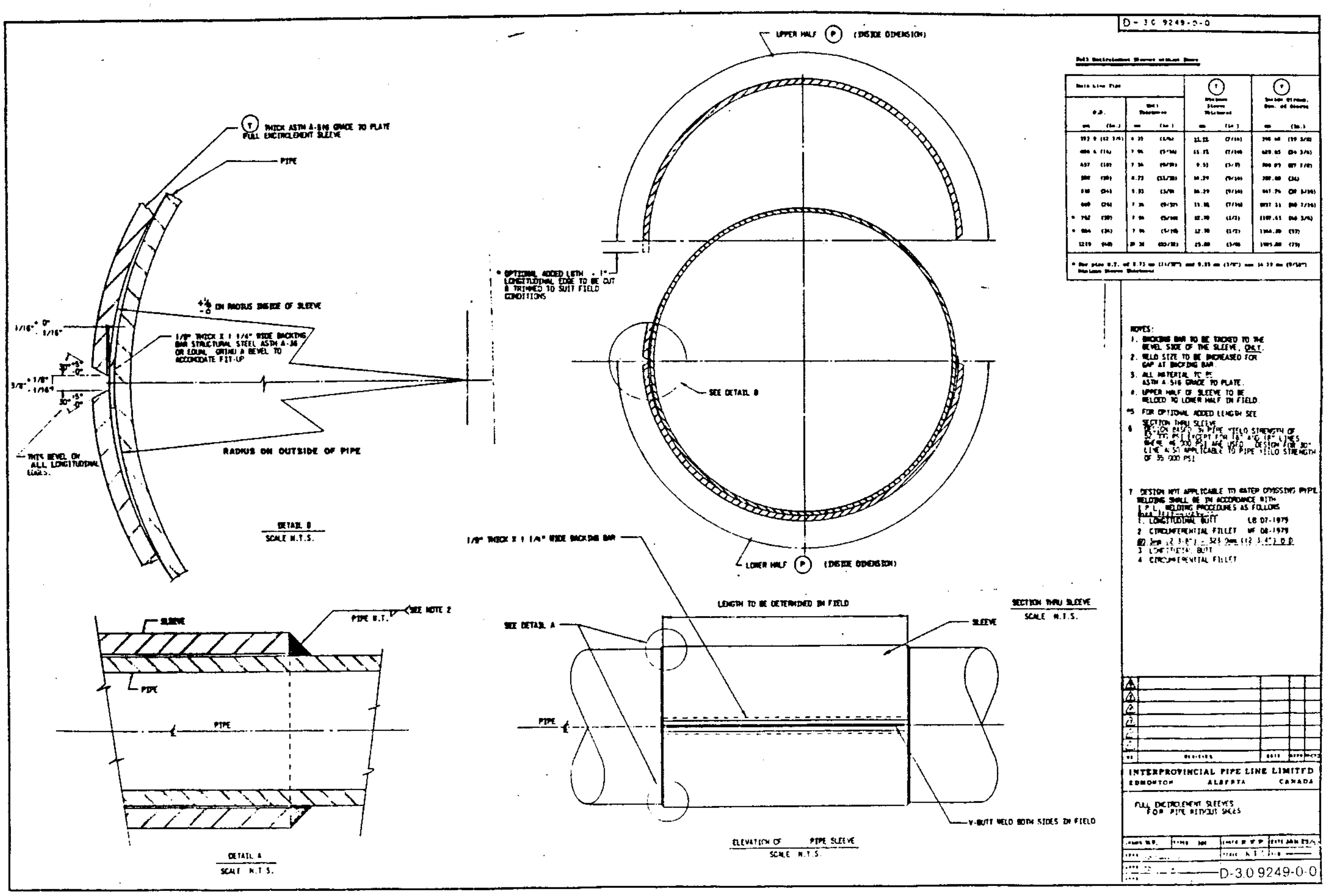


CARRIER PIPE NOMINAL DIA. IN.	CARRIER PIPE WALL THICKNESS IN.	REPAIR SLEEVE WALL THICKNESS IN.
16	0.312	0.500
20	0.312	0.500
	0.344	0.500
24	0.281	0.500
	0.312	0.500
	0.344	0.625
	0.375	0.625
34	0.281	0.500
	0.312	0.625
	0.344	0.625

NOTE:
SLEEVE TO BE ROLLED FROM ASTM A516 GRADE 70 PLATE OR APPROVED EQUAL.

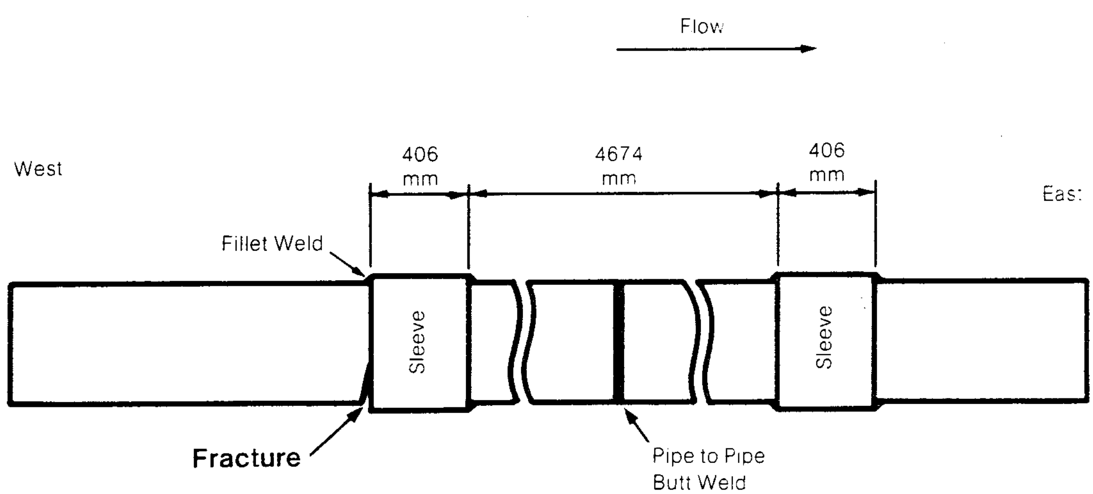
INTERPROVINCIAL PIPE LINE LIMITED EDMONTON ALBERTA CANADA	DRAWN BD	DATE 12/7/1973
	TYPED	SCALE NONE
REPAIR SLEEVE DETAIL	CHECK R.F.P.	APPR. [signature]
	APPR. [signature]	APPR. [signature]
	ENGINEERING STANDARD NUMBER —	A—3.701-6250-0-0

Appendix V



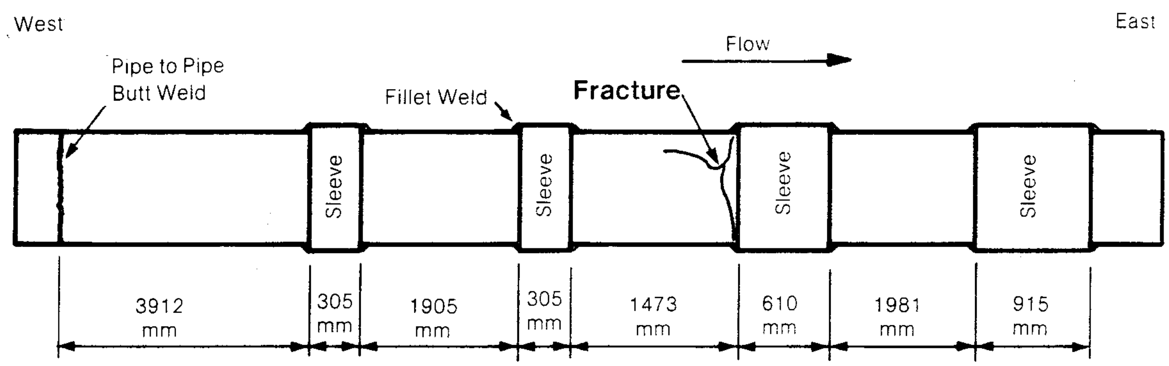
THICK ASTM A-516 GRADE 70 PLATE FULL ENCIRCLEMENT SLEEVE
PIPE
ON RADIUS INSIDE OF SLEEVE
1/8" THICK X 1 1/4" WIDE BACKING BAR STRUCTURAL STEEL ASTM A-36 OR EQUAL. GRIND A BEVEL TO ACCOMODATE FIT-UP
THIS BEVEL ON ALL LONGITUDINAL EDGES.
RADIUS ON OUTSIDE OF PIPE
DETAIL B
SCALE N.T.S.
OPTIONAL ADDED LGTH - 1" LONGITUDINAL EDGE TO BE CUT & TRIMMED TO SUIT FIELD CONDITIONS
UPPER HALF (INSIDE DIMENSION)
LOWER HALF (INSIDE DIMENSION)
SEE DETAIL B
SECTION THRU SLEEVE
SCALE N.T.S.
SLEEVE
PIPE W.T.
SEE NOTE 2
DETAIL A
SCALE N.T.S.
1/8" THICK X 1 1/4" WIDE BACKING BAR
LENGTH TO BE DETERMINED IN FIELD
SEE DETAIL A
V-BUTT WELD BOTH SIDES IN FIELD
ELEVATION OF PIPE SLEEVE
SCALE N.T.S.
NOTES:
1. BACKING BAR TO BE TACKED TO THE BEVEL SIDE OF THE SLEEVE, ONLY.
2. WELD SIZE TO BE INCREASED FOR GAP AT BACKING BAR.
3. ALL MATERIAL TO BE ASTM A-516 GRADE 70 PLATE.
4. UPPER HALF OF SLEEVE TO BE WELDED TO LOWER HALF IN FIELD.
5. FOR OPTIONAL ADDED LENGTH SEE SECTION THRU SLEEVE
7. DESIGN NOT APPLICABLE TO WATER CROSSING PIPE.
INTERPROVINCIAL PIPE LINE LIMITED
EDMONTON ALBERTA CANADA
FULL ENCIRCLEMENT SLEEVES FOR PIPE WITHOUT SAGS
D-3.0 9249-0-0

Details of Pipe Section Examined for the Incident of 19 February 1985 at Kmp 84.12



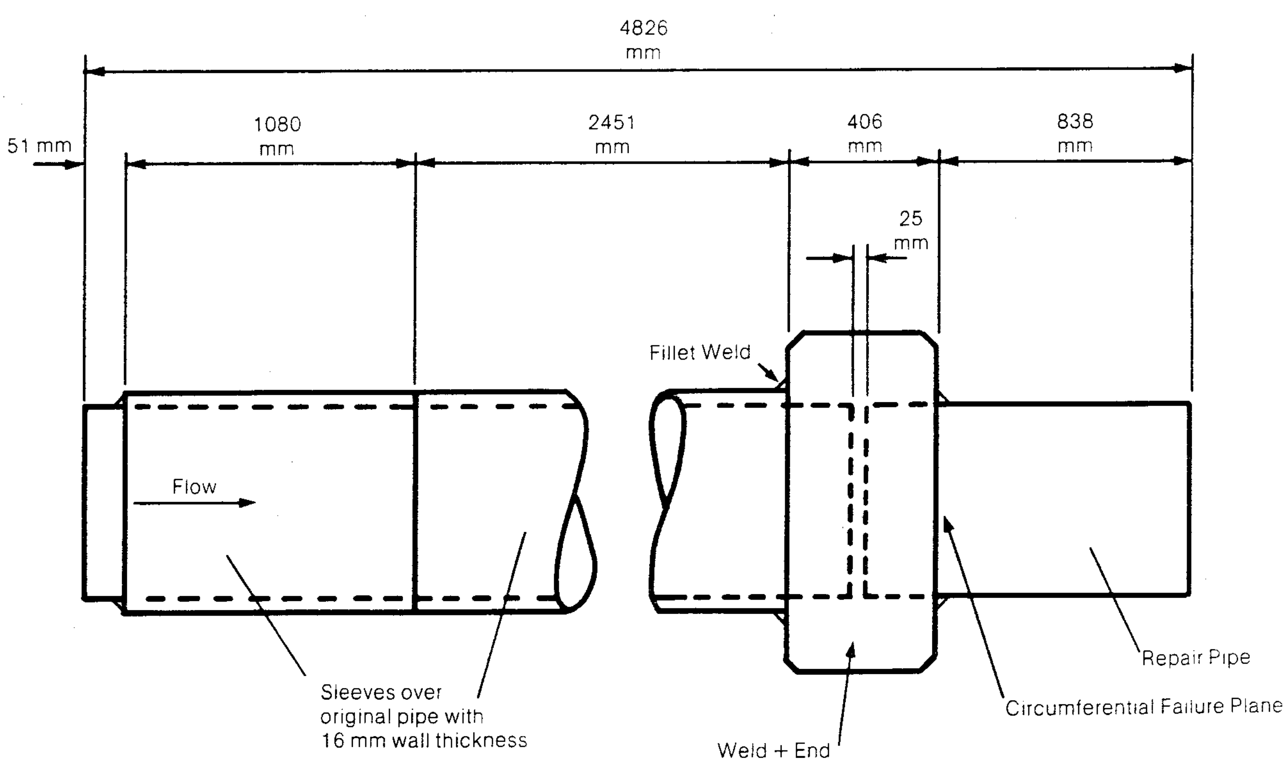
Appendix VII

Details of Pipe Section Examined for the Incident of 23 February 1983 at Kmp 82.3



Appendix VIII

Details of Pipe Section Examined for the Incident of 8 March 1976 at Kmp 121



Appendix IX

An Outline of Interprovincial Pipe Line Limited's Line No. 1 Operations on 19 February 1985 Between 07:00 and 13:05 hrs.

Evidence	Observation/Explanation
09:00 hrs. Steady pumping operation. natural gas liquids (NGL) being pumped out of Edmonton pump station (P.S.), and refined petroleum products (RPP) being delivered into Regina P.S.	For the Edmonton to Regina section the actual pumping rate between 07:00 to 09:00 hrs. was 1116 m^3/hr, while between 09:00 to 11:00 hrs. it was 1122 m^3/hr.
11:00 hrs. NGL being pumped out of Edmonton P.S., and RPP being delivered into Regina P.S.	Calculated pumping rate at Edmonton was 1057 m^3/hr. A total of 8 pump units were operating on Line No. 1 with 2 each at Edmonton and Hardisty P.S. and 1 each at Kerrobert, Milden, Loreburn and Craik P.S.
11:53:52 hrs. Suction pressure set point at Edmonton P.S. was 121 psi.	
11:54:34 hrs. Suction pressure set point was adjusted to 42 psi at the Edmonton P.S. when the case and suction pressures were 748 and 131 psi respectively.	The set point was adjusted to prepare for completion of NGL batch and the start of the synthetic crude batch. Edmonton P.S. differential pressure was 617 psi.
11:56:54 hrs. Case and suction pressures at Edmonton P.S. were 789 and 67 psi respectively.	Edmonton P.S. differential pressure was 722 psi.
11:58:48 hrs. Case and suction pressures at Edmonton P.S. were 862 and 42 psi respectively.	Edmonton P.S. differential pressure was 820 psi. The increase in differential pressure at the Edmonton P.S. between 11:54 and 11:58 hrs. indicated the arrival of the heavier synthetic batch and resulted in higher energy demand and pressure downstream of the P.S.
12:00 hrs. Edmonton discharge pressure was 879 psi while the Hardisty suction and case pressures were 330 and 1040 psi respectively and Kerrobert suction pressure was 136 psi.	The pipeline flowing conditions were as follows: between Edmonton and Hardisty P.S. pressure drop was 549 psi, and calculated flow was 1273 m^3/hr; and between Hardisty and Kerrobert P.S. pressure drop was 904 psi and calculated flow was 1163 m^3/hr.

Evidence	Observation/Explanation
12:23 hrs. Edmonton discharge pressure was 891 psi while the Hardisty suction and discharge pressures were 455 and 1040 psi respectively; and the Kerrobert suction pressure was 136 psi.	Pipeline flowing conditions were as follows: for the Edmonton to Hardisty section the pressure drop was 436 psi and calculated flow was 1116 m^3/hr; and for the Hardisty to Kerrobert section the pressure drop was 904 psi and calculated flow was 1169 m^3/hr.
12:23:31 hrs. Pump unit no. 1.3 at the Edmonton P.S. started.	To eliminate throttling at Edmonton P.S., Edmonton initiated the start up of pump unit no. 1.3, a 750 HP unit and later, at 12:30:45, initiated the shut down of pump unit no. 1.1, a 1500 HP unit. It takes approximately 3 minutes before the pump delivers at full pressure into the pipeline.
12:24:37 hrs. Edmonton P.S. suction, case and discharge pressures were 106, 998, and 891 psi respectively.	Edmonton P.S. was throttling on high case pressure when the discharge pressure set point was 887 psi.
12:24:56 hrs. Edmonton P.S. suction, case and discharge pressures were 73, 943, and 877 psi respectively.	Edmonton P.S. suction and case pressures dropped 33 and 55 psi respectively in 19 seconds.
12:24:59 hrs. Edmonton P.S. suction, case and discharge pressures were 65, 931 and 876 psi respectively.	Edmonton P.S. suction and case pressures had dropped 8 and 12 psi respectively in 3 seconds.
12:25:00 hrs. Hardisty P.S. suction, case and discharge pressures were 460, 1244 and 1040 psi respectively.	Hardisty P.S. was throttling on high case pressure due to high case pressure.
12:25:18 hrs. Edmonton P.S. suction, case and discharge pressures were 39, 887 and 876 psi respectively.	Edmonton P.S. suction and case pressure dropped 67 and 111 psi respectively in 41 seconds.
12:25:19 hrs. All pump units on Line No. 1 were operating. Hardisty P.S. suction, case and discharge pressures were 366, 1150 and 1040 psi respectively.	Both Hardisty P.S. suction and case pressures had dropped 94 psi respectively in 19 seconds.
12:26:29 hrs. Pump unit no. 1.3 at Edmonton P.S. commenced pumping.	At 12:23:31 this pumping unit started.
12:26:51 hrs. Pump unit no. 1.1 at Edmonton P.S. shut down.	Edmonton shut down unit no. 1.1, a 1500 HP unit to complete the change from 3000 HP to 2275 HP units.

Evidence	Observation/Explanation
12:27:42 hrs. Edmonton P.S. suction, case and discharge pressures were 82, 819 and 740 psi respectively.	Edmonton P.S. started throttling. The discharge and suction pressure set points were 887 and 52 psi respectively. At this point, a total of 79 psi was being throttled off between the case and the discharge pressures.
12:30:17 hrs. Edmonton P.S. suction, case and discharge pressures were 63, 803 and 612 psi respectively.	At this time, a total of 79 psi was being throttled off between the case and discharge pressures.
12:33:31 hrs. Hardisty P.S. suction, case and discharge pressures were 112, 830 and 798 psi respectively.	Hardisty P.S. started throttling on low suction pressure. The suction pressure set point was set at 123 psi.

12:37 hrs.
Status Report of Pipeline Flows

Station	Calculated flow m^3/hr
Edmonton	1098
Hardisty	779
Kerrobert	923
Milden	1065
Loreburn	1031
Craik	1120

Information appearing on the CRT screen illustrates reduced flows downstream of Hardisty and Kerrobert P.S.

Evidence	Observation/Explanation
12:37:28 hrs. Pump unit no. 1.3 at Edmonton P.S. locked out.	Unit no. 1.3 automatically shut down by Edmonton P.S. control system to protect the P.S. from low suction pressure.

12:38 hrs.
Status Report on Station Pressures (psi)

	SPSP*	Suct	Case	Disc	DPSP**
Edmonton	57	110	552	532	887
Hardisty	123	122	783	545	1036
Kerrobert	130	132	590	357	831
Milden	178	177	367	281	703
Loreburn	127	124	428	359	748
Craik	123	260	462	455	777
Regina					

All P.S.s downstream of Edmonton, with the exception of the Craik P.S., throttling on low suction pressure. From 12:23 to 12:38 hrs., the differential section pressure between Edmonton and Hardisty P.S. was reduced to 410 from 436 psi and between Hardisty and Kerrobert P.S. to 413 from 904 psi.

Note: * SPSP - suction pressure set point
** DPSP - discharge pressure set point

Evidence	Observation/Explanation
12:39:21 hrs. Pump unit no. 1.1 at Craik P.S. shut down.	Edmonton shut down unit no. 1.1 at Craik P.S. to slow the flow rate down.
12:40:18 hrs. Pump unit no. 1.1 at Edmonton P.S. started.	Edmonton initiated the start up of pump unit no. 1.1 to compensate for the loss of pump unit no. 1.3 which locked out on low suction at 12:37:28 hrs.

Evidence	Observation/Explanation
12:40:50 hrs. First leak message appeared at the bottom of the screen with alarm as follows: "Line 1 suspected leak YP (Hardisty P.S.)"	Pipeline flowing conditions at this time were as follows:
12:41:59 hrs. Pump unit no. 1.2 at Loreburn P.S. shut down.	Edmonton initiated the shut down of pump unit no. 1.2 at Loreburn.
12:43:19 hrs. Pump unit no. 1.1 at Kerrobert P.S. locked out.	Pump unit no. 1.1 was shut down by the automatic station control on low suction pressure.
12:43:32 hrs. Pump unit no. 1.1 at Milden P.S. shut down.	Edmonton initiated the shut down of pump unit at Milden.
12:43:45 hrs. Pump unit no. 1.1 at Edmonton P.S. commenced pumping into the line.	At 12:40:18 unit no. 1.1 was started up by Edmonton.
12:44:33 hrs. Pump unit no. 1.3 at Hardisty P.S. shut down.	Edmonton initiated the shut down of pump unit no. 1.3, to eliminate throttling on low suction at the station.
12:45:56 hrs. A second leak message appeared at the bottom of the screen with alarm as follows: "Line 1 suspended leak YP (Hardisty P.S.)"	Pipeline flowing conditions at this time were as follows:
12:48:52 hrs. Pump unit no. 1.1 at Kerrobert P.S. started.	Edmonton initiated the start up of pump unit no. 1.1 at Kerrobert.
12:51:01 hrs. Third leak message appeared at the bottom of the screen with alarm as follows: "Line 1 suspended leak YP (Hardisty P.S.)"	Pipeline flowing conditions at this time were as follows:
12:52:21 hrs. Pump unit no. 1.1 at Kerrobert P.S. commenced pumping into the line.	

Flowing conditions at 12:40:50 hrs.:

Station	Calculated flow m^3/hr
Edmonton	1045
Hardisty	697
Kerrobert	760

Flowing conditions at 12:45:56 hrs.:

Station	Calculated flow (m^3/hr)
Edmonton	1111
Hardisty	470
Kerrobert	372

Flowing conditions at 12:51:01 hrs.:

Station	Calculated flow (m^3/hr)
Edmonton	1233
Hardisty	513
Kerrobert	483

Evidence	Observation/Explanation
12:52:52 hrs. Pump unit no. 1.1 at Kerrobert P.S. locked out automatically on low suction.	The unit shut down automatically by station control because the suction pressure had dropped below the suction pressure set point upon commencement of pumping by the unit. Edmonton had initiated start up of the unit at 12:48:52.
12:53:24 hrs. Suction pressure set point at Kerrobert P.S. adjusted upward to 198 psi from 130 psi.	Suction pressure was 258 psi when Edmonton increased the suction pressure set point to 198 psi.
12:54:14 hrs. Pump unit no. 1.2 at Kerrobert P.S. started.	Edmonton initiated the start up of pump unit no. 1.2.
12:54:49 hrs. Pump unit no. 1.1 at Midlen P.S. started.	Edmonton initiated the start up of unit no. 1.1.
12:56:07 hrs. Fourth leak message appeared at the bottom of the screen with alarm as follows:"Line 1 suspended leak YP (Hardisty P.S.)"	Pipeline flowing conditions at this time were as follows:

Station	Calculated flow (m^3/hr)
Edmonton	1249
Hardisty	523
Kerrobert	485

Evidence	Observation/Explanation
12:57:04 hrs. Suction pressure set point at Loreburn P.S. adjusted upward to 201 psi from 127 psi.	Suction pressure set point increased by Edmonton.
12:57:19 hrs. Pump unit no. 1.2 at Loreburn P.S. started.	Edmonton initiated the start up of pump unit no. 1.2.
12:57:39 hrs. Suction pressure at Kerrobert P.S. was 291 psi.	Suction pressure set point of 198 psi at this time.
12:58:03 hrs. Pump unit no. 1.2 at Kerrobert P.S. commenced pumping into the line.	At 12:54:14 hrs. pump unit no. 1.2 started up.
12:58:04 hrs. Pump unit no. 1.1 at Milden P.S. commenced pumping into the line.	At 12:54:49 hrs. pump unit no. 1.1 started up.
12:59:12 hrs. Pump unit no. 1.2 at Kerrobert P.S. locked out.	This unit had commenced pumping into the pipeline at 12:58:03 hrs. and was shut down automatically by station control on low suction pressure.
12:59:42 hrs. Pump unit no. 1.2 at Loreburn P.S. shut down.	Edmonton initiated the shut down of the pump unit prior to the commencement of pumping into the pipeline. Pumping unit started up by Edmonton at 12:57:19 hrs.

Evidence	Observation/Explanation
13:01:13 hrs. Fifth leak message appeared at the bottom of the screen with announciation alarm as follows:"Line 1 suspected leak YP (Hardisty P.S.)"	Pipeline flowing condition at this time were as follows:

Station	Calculated flow (m^3/hr)
Edmonton	1255
Hardisty	574
Kerrobert	555

Evidence	Observation/Explanation
13:03 hrs. Phone message indicating possible pipeline incident received by shift dispatcher from Mr. Ken Lien.	Shift dispatcher received a phone call regarding visible cloud in a field adjacent to the Ryley Road.
13:03:11 hrs. Pump unit no. 1.1 at Edmonton P.S. shut down.	Edmonton initiated shut down of Line No. 1 pumping units.
13:03:15 hrs. Pump unit no. 1.2 at Edmonton P.S. shut down.	Edmonton initiated shut down.
13:03 hrs. Pump unit no. 1.1 at Milden P.S. shut down.	Edmonton initiated shut down.
13:04:21 hrs. Pump unit no. 1.1 at Hardisty P.S. shut down.	Edmonton initiated shut down.

Table 1
IPL Line No. 1 Sectionalizing Valves
Edmonton to Hardisty

Location	Km Post	Comments
Edmonton Terminal downstream station boundary	0.00	Motor operated
Main Line	8.19	Remotely operated
Main Line	15.18	Remotely operated
Main Line	27.65	Remotely operated
Kingman Station upstream station boundary	51.24	Remotely operated
Main Line	60.56	Remotely operated
Main Line	69.40	Remotely operated
Main Line	93.84	Hand operated
Strome Station upstream station boundary	112.13	Remotely operated
Main Line	142.64	Remotely operated
Main Line	154.05	Remotely operated
Main Line	168.21	Remotely operated
Hardisty Station upstream station boundary	175.45	Remotely operated

Table 2
Chemical Properties of Pipe in IPL System

Line	C	Mn	P	S	CE	Comments
1	0.32	1.03	0.014	0.025	0.49	(1) installed 1950
2	0.32	1.04	0.016	0.036	0.49	(1) installed 1956
3	0.31	1.14	0.015	0.027	0.50	(1) installed 1967
4	0.20	1.38	0.020	0.014	0.43	(1) installed 1972
2	0.25	1.12	0.013	0.012	0.44	8 March 1976 incident (2)(3)
1	0.32	1.03	0.014	0.025	0.49	23 February 1983 incident (2)
1	0.29	1.15	0.019	0.027	0.48	19 February 1985 incident (2)

Comments:
- (1) Average chemistry from mill reports
- (2) Actual chemistry of pipe involved in incident
- (3) Failed repair pipe manufactured in 1969

Abbreviations:
- C carbon
- CE carbon equivalent
- Mn manganese
- P phosphorus
- S sulphur