SMART ACTIVITY ID
129700

APR 1 2 ...

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

	Inspection Report	Post Inspection Memorandum	
Inspector/Submit Date:	Dan Christensen 04/01/2010	**Inspector/Submit Date:**	Dan Christensen/04/01/2010 DGC 04/07/10
		Peer Reviewer/Date:	ESS 4/07/2010
		Director Approval	

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Pipelines (North Dakota) LLC	**OPID #:**	15774
Name of Unit(s):	ND to Clearbrook - IU 16143	**Unit #(s):**	16143
Records Location:	2505 16th St. SW		
Unit Type & Commodity:	Crude Oil		
Inspection Type:	Accident Investigation Involving Hazardous Liquid	**Inspection Date(s):**	No site visit
For OPS :		**AFO Days:**	
For MNOPS :	Dan Christensen/Jeff Murray	**AFO Days:**	0
MNOPS CASE #:	1153071		

Synopsis: On Monday, March 1, 2010 crude oil was released in the Enbridge pipelines, Clearbrook Terminal. At approximately 9:16 AM CST, an accidental valve closure occurred as a result of controller error at their Edmonton, Canada control center, causing line 81 to build up enough back pressure to force the thermal reliefs and rupture pin to relieve to the station sump. The station sump overflowed and approximately 3 barrels were released. The spill was contained in the facility and cleaned within 27 hours.

Jeff Murray and Dan Christensen, with the Minnesota Office of Pipeline Safety, reviewed the "Incident Review Clearbrook Terminal", final document prepared by Quentin Hill, Compliance Coordinator for Gathering Systems Support Services for Enbridge Pipelines (North Dakota) LLC. No report date was indicated on the final report. The Minnesota Office of Pipeline Safety has not received the electronically attached files for this report. The received file, CBdnv1.pdf, is attached.

The report states on page 4, "There are no indications of violating maximum operating pressures for the terminal piping due to pressure recording deficiencies". This information is inconclusive as there was no supporting documentation found to support this statement. The SCADA graph on page 10 of this report shows the maximum operating pressure for PT2 above 393.59 PSI. Although the results from the SCADA graph on page 10 may not be accurate, the SCADA graph does not prove that the pressure within the pipe did not violate maximum operating pressure. The investigation will continue.

Summary: On March 1, 2010, approximately 3 barrels of crude oil was released in the Clearbrook Terminal. An incident report was put together regarding this incident. The report is inconclusive and further investigation is necessary.

RECEIVED JUL 2 7 2009

SMART ACT-125641 BEP

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the Standard **Inspection Report.**

Ronald J. Wiest

Inspection Report		**Post Inspection Memorandum**
Inspector/ Submit Date:	Ron Wiest July 10, 2009	**Inspector/Submit Date:** Ron Wiest, MNOPS Senior Inspector July 10, 2009
		Peer Reviewer/Date: ESS 7-21-2009 ESS
		Director Approval

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:** 11169	
Name of Unit(s):	Deer River - Superior - IU 3083	**Unit #(s):** 3083	
Records Location:	119 North 25th Street East Superior, WI 54880		
Unit Type & Commodity:	Crude		
Inspection Type:	Pipeline Failure - Material Defect	**Inspection Date(s): June 9 - 11, 2009**	
For OPS :		**AFO Days:**	
For MNOPS :	Ron Wiest, Senior Inspector	**AFO Days: 3**	
MNOPS CASE #:	1114011		

Synopsis: The leak date was reported to have been discovered on June 9th 1505 hours by right of way personnel. Various conversations with Enbridge personnel over the course of the next three days brought to light that Enbridge had reason to believe that they possibly had a leak in this area on June 5th but did not make any notifications to State or Federal Agency. The pipelines had been shut-down for a period of time but at that time they rationalized that they did not have a leak and restarted the pipeline. Enbridge believed that the oily residue on the ground and vegetation must have been from another source. They took a sample for laboratory testing. The circumstances surrounding this possible leak discovery , restarting without definitive determination and not providing any type of notifications to state or federal agencies needs to be explored further for possible failure to follow procedures.

The leak was determined to be from a crack in the adjacent area of a horizontal weld between the bar stock replacement metal for the flange bolt material and the body of the Plidco split sleeve flange body (See Picture A). The leak was repaired by welding a 2 inch socket weld pipe end cap over the

Summary: Al Aleknavisius of Enbridge notified the DO that a leak was reported to them by an unidentified employee.

The 5 barrel leak was on line 2 (26 inch) at MP 1056.12 in the NE section 17 of T50N, R19W, St. Louis County, Minnesota on state owned land being managed by St. Louis County. The recent rains made travel down the ROW impossible and the leak site was a low area.

Discussion:

An attempt to travel to observe the leak and repair was made on June 9th, but the lateness of the notification and the expedited timetable for the repairs before nightfall made getting to the site before it was all over was nearly impossible. Communications with MNOPS Chief Engineer, Elizabeth Skalnek and Enbridge personnel Al Aleknavicius, Bill Palmer, Adam Erickson, Dave Hoffman and PHMSA Central Region representative Brian Pierzina, continued for a couple of hours with a final determination to dispatch Ron Wiest at about 7 PM. The ETA to the site would have been about 10:30 PM. Ron Wiest kept in contact with Adam Erickson on the repair status while in route and when the second crack repair had been completed, Ron Wiest was still an hour away. All things considered, including the mosquito infestation that evening, it was decided to meet at the road side staging area the next morning at about 7 AM. Adam would obtain a set of pictures for MNOPS of the before repaired fitting.

Ron Wiest arrived at the staging area shortly after 7 AM and Adam Erickson came from the leak site to provide transportation to the leak repair site about one mile from the road, but 20 minutes of trail riding in a John Deere Gator ATV through the woods and ridges.

Pictures were taken of the site, fitting and the repairs, plus conversation with the crew foreman and with Adam on the events that lead up to the June 9th events were discussed. Discussion topics included:

- The 1989 leak repair procedure included the replacement of the bolts with bar stock so that they could be welded in place.
- The 30 inch long Plidco split sleeve was over a 20 inch long dent of about 2-3 inch deep with a hairline crack at the leading edge. (Information from the 04-18-1989 repair report)
- The circumstances relating to the week before concerning the investigation into residual oil being found, pipeline shutdown and subsequently restarted late Friday June 5th were discussed in great length, but not in great detail as to why no notifications were provided to Minnesota or federal agencies.
- The "discovery" of the leak was made officially on site after actual oil was observed to be weeping from a weld. At about the same time a laboratory test of the oil reported that the residual oil found the week before was in fact Enbridge's crude.
- This current repair of a repair procedure was reported to have been approved by Enbridge engineering and management staff with consultation with Plidco representatives on Monday, June 8th.
- The 2 inch weld caps were provided to Enbridge by Plidco according to Adam Erickson.
- The mag particle test was successfully completed about 11:30 AM with the recoating of the pipe commencing immediately there after.

Pictures and information obtained will be sent electronically on a CD with this hard copy report which will be sent electronically with only a few photos.

Findings:

All of the circumstances and events before and during this event and subsequent repair method lead to more questions and the need to have additional information to fully comprehend the facts to establish what could continue to be a leak scenario problem or a difficult situation to prevent recurrence. The following items should be requested from Enbridge to help develop a greater understand of the circumstances and events:

1. Patrolling records, notes, reports and documents for three months prior to July 10, 2009.
2. The chronological listing of events, their characteristics and Enbridge course of actions and decisions relating to the discovery of the residual oil found at this previously repaired leak site in the weeks prior to June 9th "discovery" at about 1505 hours.
3. How many Plidco split sleeves were installed on any pipeline size possibly using the same installation procedure especially the replacement of the bolts with welded bar stock.
4. The locations of such installations whether they have been replaced or repaired since, on any pipeline. This would provide insight on the risk of a leak or validate the leak history of Plidco split sleeve installations and/or repairs. This would be from the beginning of their use.
5. Enbridge needs to complete an analysis to determine cause and prevent recurrence by completing an investigation according to 195.402(a)(5).
6. Copies of the initial Plidco sleeve installation procedure that includes the stud or bolt removal, replacement with bar stock and the annular space between the bar stock and the new procedure with the weld cap fitting welded over the bar stock weld.
7. All of the documentation and records required for compliance with 195.118(a) and 195.422(a & b) for the initial Plidco split sleeve repair procedure and for the repair of the repair procedure done July 9th that includes specifications for the specific weld cap used and the welding of the cap over the leak crack.
8. The weld cap is now a pressure containment fitting/vessel that needs to meet or exceed the design requirements of the manufacturer. A two hour internet search of currently available fittings based upon the description of the weld cap fitting and the pictures; did not produce an equal or similar weld cap fitting description or picture.

MNOPS will await direction from PHMSA Central Region Director, Ivan Huntoon on a recommended course of action before preparing and presenting the request for specific information (RSI) to Enbridge directly.

STATE OF MINNESOTA

Department of Public Safety - Bureau of Criminal Apprehension
1430 Maryland Ave. East St. Paul, MN 55106

MINNESOTA DUTY OFFICER

Bureau of Criminal Apprehension Operations Center

Report #: 104063	Report Date: 6/9/2009	Report Time: 16:35	DO#: 8

CALLER INFORMATION

Contact: Al Aleknavicius
Company: Enbridge Energy Partners
Address: 119 No. 25th St East
City: Superior
State: WI **Zip:** 54880-
Phone: (715) 394-1415 **Ext:**
Alt phone: (218) 591-2818 **Ext:**
Have local police and/or fire been notified?

NARRATIVE

Today while investigating report of oil on right of way; dug up a weeping fitting on a line. The contaminated soil will go to an approved landfill.
Line is down and repairs are underway.

INCIDENT REPORT: SPILLS

RESPONSIBLE PARTY/PROPERTY OWNER

Contact: Al Aleknavicius
Company: Enbridge Energy Partners
Address: 119 No. 25th St East
City: Superior
State: WI **Zip:** 54880-
Phone: (715) 394-1415 **Ext:**
Alt phone: (218) 591-2818 **Ext:**

SPILL INFORMATION

Material: crude oil
Quantity: 5 barrels
Incident date: 6/9/2009
Time: 15:05
Is the spill ongoing? No

SPILL LOCATION

Name: Line 2
Address:
City: Gowan
County ST. LOUIS
Section: 17 sw of the ne corner
Range: 19 W
Township: 50 N
Legal:

Released to: Soil
Spill area: Rural
Have any sewers been impacted? no
Surface waters impacted? no
If A.S.T. is involved, is there secondary containment around the tank?
Type:
Kind of spill: Spill/Release
Has the material escaped the location property?
Has the released material been contained?
Is this a SARA Title, Section 304 release?
Is a CAT/ERT being requested?

ANY QUESTIONS - PLEASE CONTACT THE MN DUTY OFFICER AT 651-649-5451 or 800-422-0798

In:	Out:	Link:	Date:	Time:	Agency:	County:	Method of Contact:
☐	☑	☐	6/9/2009	16:44	OPS On-call		Phone

Narrative: Ron Wiest advised

In:	Out:	Link:	Date:	Time:	Agency:	County:	Method of Contact:
☐	☑	☐	6/9/2009	16:47	OPS		Email & Fax

Narrative:

In:	Out:	Link:	Date:	Time:	Agency:	County:	Method of Contact:
☐	☑	☐	6/9/2009	16:50	MPCA On-call		Phone

Narrative: Jason Moran advised

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 908091

INCIDENT DESCRIPTION

*Report taken by: CIV NICHAULUS THREATT at 17:30 on 09-JUN-09
Incident Type: PIPELINE
Incident Cause: EQUIPMENT FAILURE
Affected Area:
Incident was discovered on 09-JUN-09 at 15:05 local incident time.
Affected Medium: SOIL SOIL

REPORTING PARTY

Name: AL ALEKNAVICIUS
Organization: ENBRIDGE ENERGY PARTNERS
Address: 119 NORTH 25 ST EAST
SUPERIOR, WI 54880
ENBRIDGE ENERGY PARTNERS reported for the responsible party.
PRIMARY Phone: (715)3941415
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: AL ALEKNAVICIUS
Organization: ENBRIDGE ENERGY PARTNERS
Address: 119 NORTH 25 ST EAST
SUPERIOR, WI 54880
PRIMARY Phone: (715)3941415

INCIDENT LOCATION

SEE LEGAL DESCRIPTION County: ST. LOUIS
State: MN
Section: SE NE 17 Township: 50 N Range: 19 W
RURAL AREA

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 5 BARREL(S)

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A DISCHARGE OF CRUDE OIL FROM A 26 INCH STEEL PIPELINE DUE TO A FITTING THAT WAS LEAKING. CALLER WAS NOTIFIED OF DISCHARGE AT 1505 CDT.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS: NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type		Description of Closure	Hours Closed	Direction of Closure	
Air:	N				
Road:	N				Major Artery: N
Waterway:	N				
Track:	N				

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

CALLER STATES THE LINE WAS SHUTDOWN, REPAIRS WILL BE MADE AND THE CONTAMINATED SOIL WILL BE REMOVED.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

Weather: OVERCAST, 55||F

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: NONE
State/Local On Scene: NONE
State Agency Number: NONE

NOTIFICATIONS BY NRC

ATLANTIC STRIKE TEAM (MAIN OFFICE)
09-JUN-09 17:36 (609)7240008
USCG ICC (ICC ONI)
09-JUN-09 17:36 (301)6693363
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
09-JUN-09 17:36 (202)3661863
U.S. EPA V (MAIN OFFICE)
(312)3532318
FLD INTEL SUPPORT TEAM DETROIT (COMMAND CENTER)
09-JUN-09 17:36 (216)8576279
MN BUREAU OF CRIMINAL APPREHENSION (OPERATIONS CENTER)
09-JUN-09 17:36 (651)6495451
MN DEPT OF HEALTH (MAIN OFFICE)
09-JUN-09 17:36
MN U.S. ATTORNEY'S OFFICE (MAIN OFFICE)
09-JUN-09 17:36 (612)6645742
NTL ENVMTL EMERG CENTRE CANADA (MAIN OFFICE)
09-JUN-09 17:36 (819)9973742
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
09-JUN-09 17:36 (202)2829201
NOAA RPTS FOR MN (MAIN OFFICE)
09-JUN-09 17:36 (206)5264911
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
09-JUN-09 17:36 (202)3660568
WI DEPT NAT RES BUREAU OF LAW ENF (MAIN OFFICE)
09-JUN-09 17:36 (800)9430003

USCG DISTRICT 9 (COMMAND CENTER)
09-JUN-09 17:36 (216)9026109

ADDITIONAL INFORMATION

CALLER WILL NOTIFY STATE AGENCIES.

*** END INCIDENT REPORT #908091 ***

INTERPROVINCIAL PIPE LINE LIMITED / LAKEHEAD PIPE LINE COMPANY, INC.

BREAK OR LEAK REPORT ☐
PERMANENT REPAIR REPORT ☒

REPORTING OFFICE -	DATE AND TIME (MST) OF BREAK	DATE OF REPAIR	DATE OF REPORT
District 3	04-09-89 0700	04-10-89	04-18-89

PIPE LINE LOCATION - PUMPING STATION OR MILEAGE MARKER	LINE SIZE	ATLAS SHT. NO.	SPECIAL COST NO.
MP 1056.12	26"	217	D3-90-89

SPECIFIC LOCATION - FOOTAGE FROM A KNOWN STATIONING ON THE ATLAS DRAWING (SPECIFY)
5,101' downstream of Headquarters Lake (Tote Rd.) at St. #14910+61

QUARTER	SECTION	TOWNSHIP	RANGE	TRACT NO.	MERIDIAN - COUNTY	PROVINCE - STATE
NE	17	50N	19W	158/158A	St. Louis	Minnesota

NAME AND ADDRESS OF PERSON REPORTING LEAK

WAS REPORT FEE PAID? AMOUNT ☐ NO ☒ YES $100.

State of Minnesota, St. Louis County Board, 217 Court House, Duluth, MN

PROPERTY TENANT'S NAME AND ADDRESS

FULL DESCRIPTION OF PROPERTY DAMAGE : SHOW BY APPROPRIATE SKETCH.

An area of approximately 1½ acres of Alder brush and Ash trees was cut and burned in order to facilitate the clean up of crude oil.

EXPLAIN BRIEFLY BELOW, ANY REQUEST OR DISCUSSION WITH OWNER OR TENANT CONCERNING DAMAGES TO PROPERTY WHICH MAY HAVE ARISEN VOLUNTARILY WITHOUT INVESTIGATION ON YOUR PART.

NATURE AND CAUSE OF BREAK OR LEAK Leak was caused by a large rock underneath the pipe at 6:00 position, creating a 20" long dent, 2" - 3" in depth. At the leading edge the dent was a hairline crack.

NATURE OF REPAIR & FITTINGS ADDED TO MAIN LINE: SHOW BY APPROPRIATE SKETCH.

A 30" long Plidco repair sleeve was bolted in place and welded for permanent repair on April 10, 1989.

NATURE AND KIND OF SOIL	BARRELS OF OIL OUT OF LINE	CRUDE TYPE	BATCH NO.
Swamp	100	LSX	708
GENERAL CONDITION OF LINE	BARRELS OF OIL RECOVERED	DISPOSITION OF LOST OIL	
Excellent	30	Residual oil in the swampy area was	
GENERAL CONDITION OF COATING	NET LOSS - BBLS.		
Excellent	70	burned off.	

REMARKS

REPORTED TO GOVERNMENTAL AGENCIES: FEDERAL, PROVINCE/STATE, COAST GUARD, ETC.

AGENCY	INDIVIDUAL CONTACTED	DATE	TIME	
DOT National Response Center	Mr. James Heard (Rpt. #5167)	4-9-89	1045 MST	☒ TELEPHONE ☐ LETTER
MN Emergency Response Center	Duty Officer Ms. Kris Eide	4-9-89	1050 MST	☒ TELEPHONE ☐ LETTER
				☐ TELEPHONE ☐ LETTER

SIGNED [signature]

APPROVED DIV. MGR. [signature]

NUMBER OF THIS REPORT
PERMANENT REPAIR
BREAK OR LEAK Central No. 1223

Form F-17A (1976)
1. White - Division Office
2. Green - District Office
3. Yellow - Retain

ENBRIDGE™

Incident Investigation Report

Line 61 Trap Sump Overflow Release on May 21, 2009

Enbridge LRS #2370

Final Report Date: August 7, 2009

Summary of Events

On May 21, 2009 the Edmonton Control Center (CCO) and a Superior Area Electrical Technician were testing isolate and de-isolate commands on Line 61 at Superior Terminal. These commands would close or open a number of valves at the Line 61 Pig Launch Facility. Two valves on the sending trap were locked out due to pig loading operations and required lock-out device removal to facilitate the test. The Electrical Technician requested and received approval via phone from the Pipe Line Maintenance (PLM) Team Lead to remove the locks/tags. The Technician then obtained the keys from the local MCC building where they were stored, removed the locks/tags, contacted CCO, and gave the Line Operator clearance to issue the isolate and/or de-isolate commands. The Line Operator then issued the isolate command at which time a number of valves closed. The Operator then issued the de-isolate command at which time a number of valves opened, two of which were the mainline valves isolating the trap from the mainline. At the time, unknown to the Technician, the vent line that leads from the trap to the sump tank was open. When the mainline valves opened, oil filled the trap and overfilled the trap sump tank. The two mainline valves were closed, and the flow subsided. The technician performed initial containment actions and engaged the Incident Command system.

What Resulted

The event resulted in approximately 150 barrels of oil escaping. All oil was contained within existing terminal containment structures. Company and contract personnel immediately responded and began initial cleanup efforts involving the removal of contaminated soil and skimming of oil off of the terminal containment ponds. All free product and contaminated soil was removed from the site over the next several days and no residual environmental impacts are anticipated.

Root Causes

There are a number of root causes that led up to this incident. Had any one of these factors been removed, the incident may not have occurred.

1. The Technician did not identify the vent valve as being open.
2. The permanent thermal relief system had not yet been installed on the trap.
3. The Control Center Operator does not see the status of the vent valves
4. No Lockout/Tagout Log was filled out in this case.
5. Lockout/Tagout requirements for group lockout within the O&MP manuals are unclear.
6. The interim procedure that was in place for this operation did not go through the same review process as the permanent procedure.
7. The PLM Team lead issued approval to the technician allowing him to remove the locks without making provisions to verify all valves were closed.

8. No pressure piping isolation form was completed for this work.
9. The vent valve (interim thermal relief) was open, when it could have been closed as the trap was mostly empty.

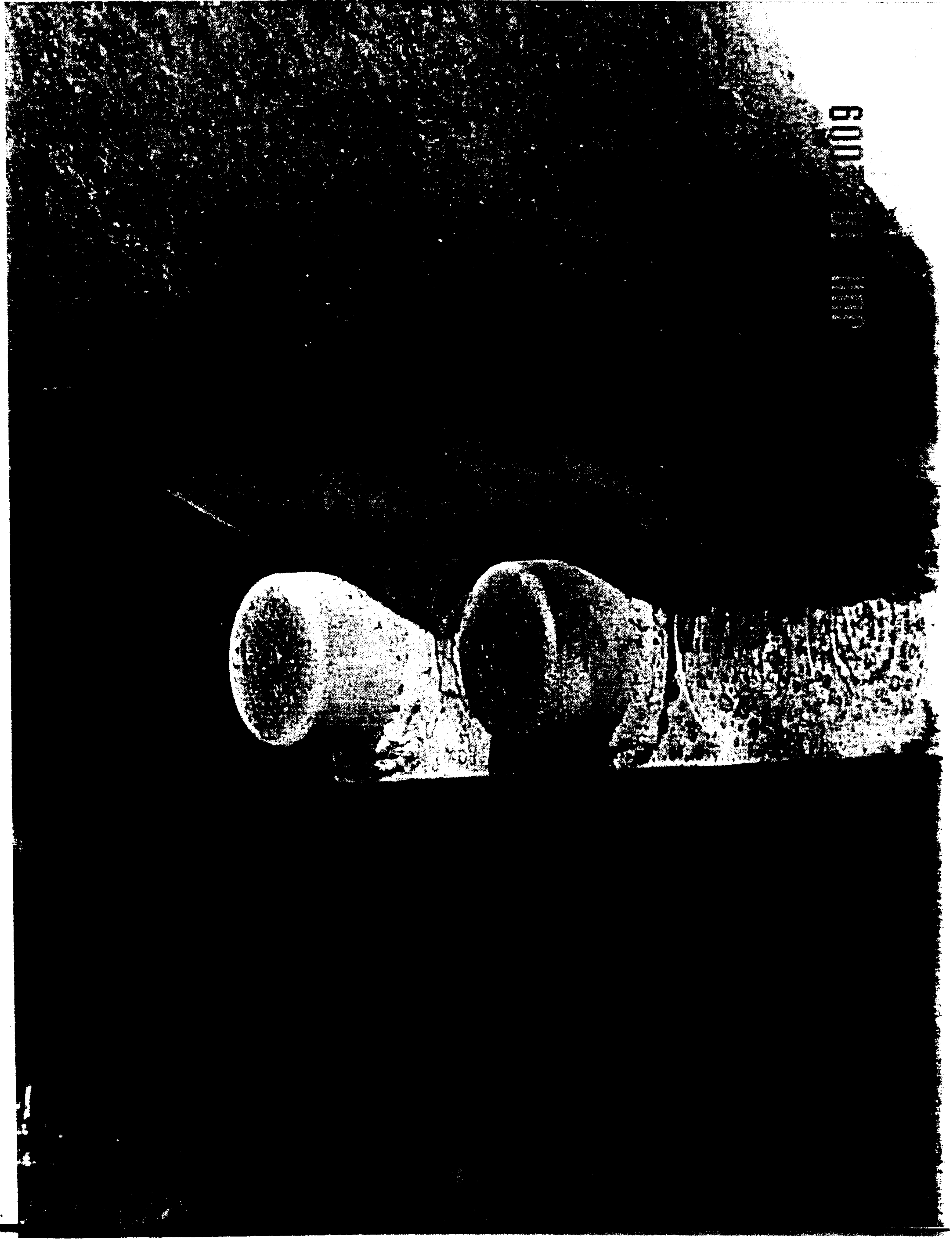
Remedial Actions

There are a number of actions that will be undertaken as a result of this incident.

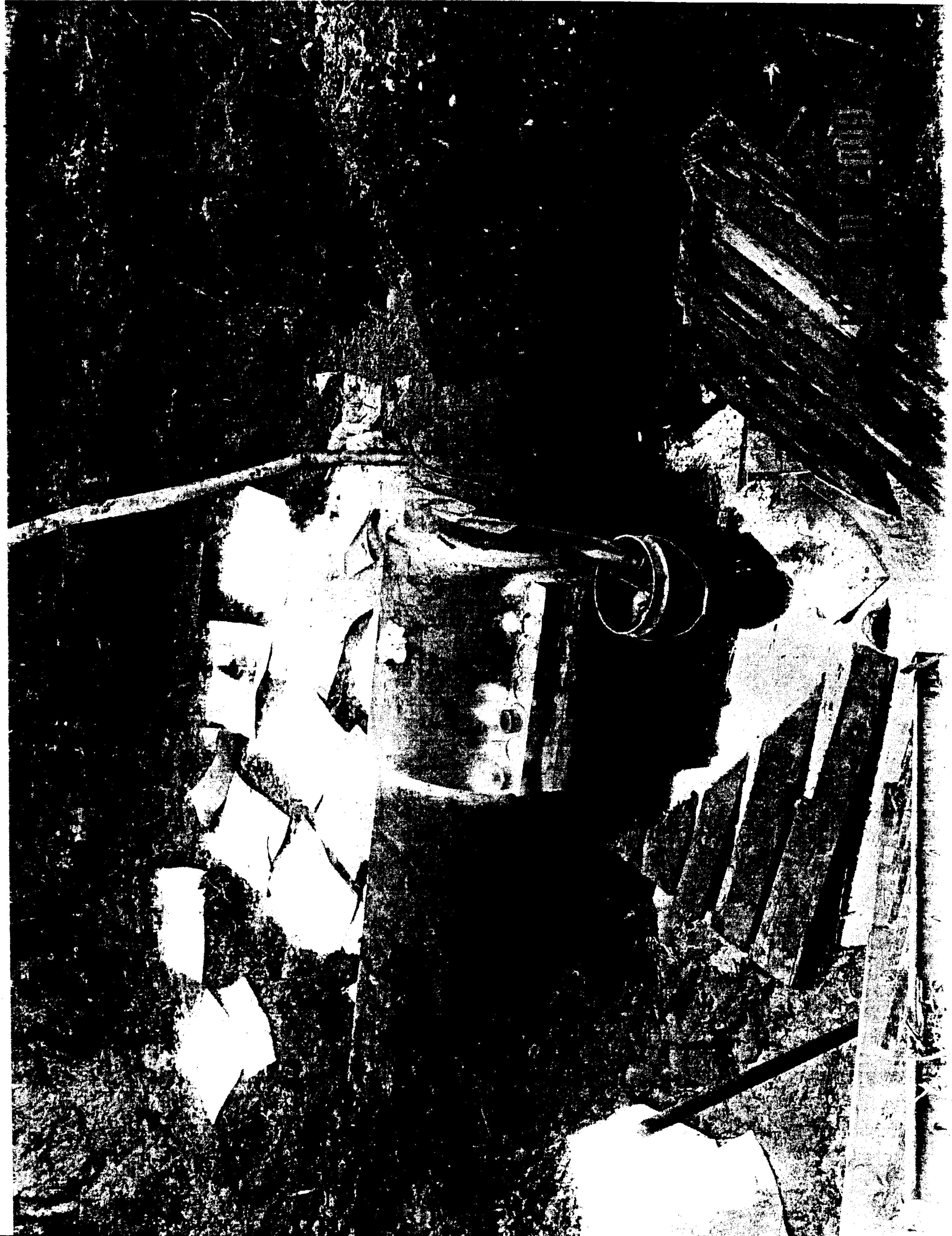
1. The Superior Region Safety Coordinator will review the lockout / tagout system training, hazard assessment system training, and safe work permit system training and ensure that it is understood by applicable employees that these systems are mandatory.
2. The Superior Region Safety Coordinator will re-train the Superior PLM Crew on Lockout / Tagout procedures with emphasis on the use of the lockout/tagout log.
3. The Senior Safety Coordinator will review the O&MP group lockout / tagout section for adequacy and compliance with OSHA regulations, particularly surrounding group lockout, key control, personal locks, and removal of locks. Appropriate changes will be made to the procedures and affected employees will receive training on the revised procedure.
4. The Superior Region Supervisor of Regional Engineering and Services will revise the interim trap operation procedure to reflect details from the permanent procedure.
5. The Superior Region Supervisor of Regional Engineering and Services and the Power and Controls Group will conduct a review of the trap sump pump system design and operation, including the system control logic, to evaluate if any changes would improve overfill protection and detection.
6. The Major Projects Facilities Group will complete installation of the permanent thermal relief system.
7. The mandatory need to complete the pressure piping isolation form will be reinforced at the next Regional Environmental, Health, and Safety Committee Meeting.
8. The Supervisor, Regional Engineering and Services will work with the Company's Training Coordinator to review the thermal overpressure training requirements for Pipeline Maintenance Workers.

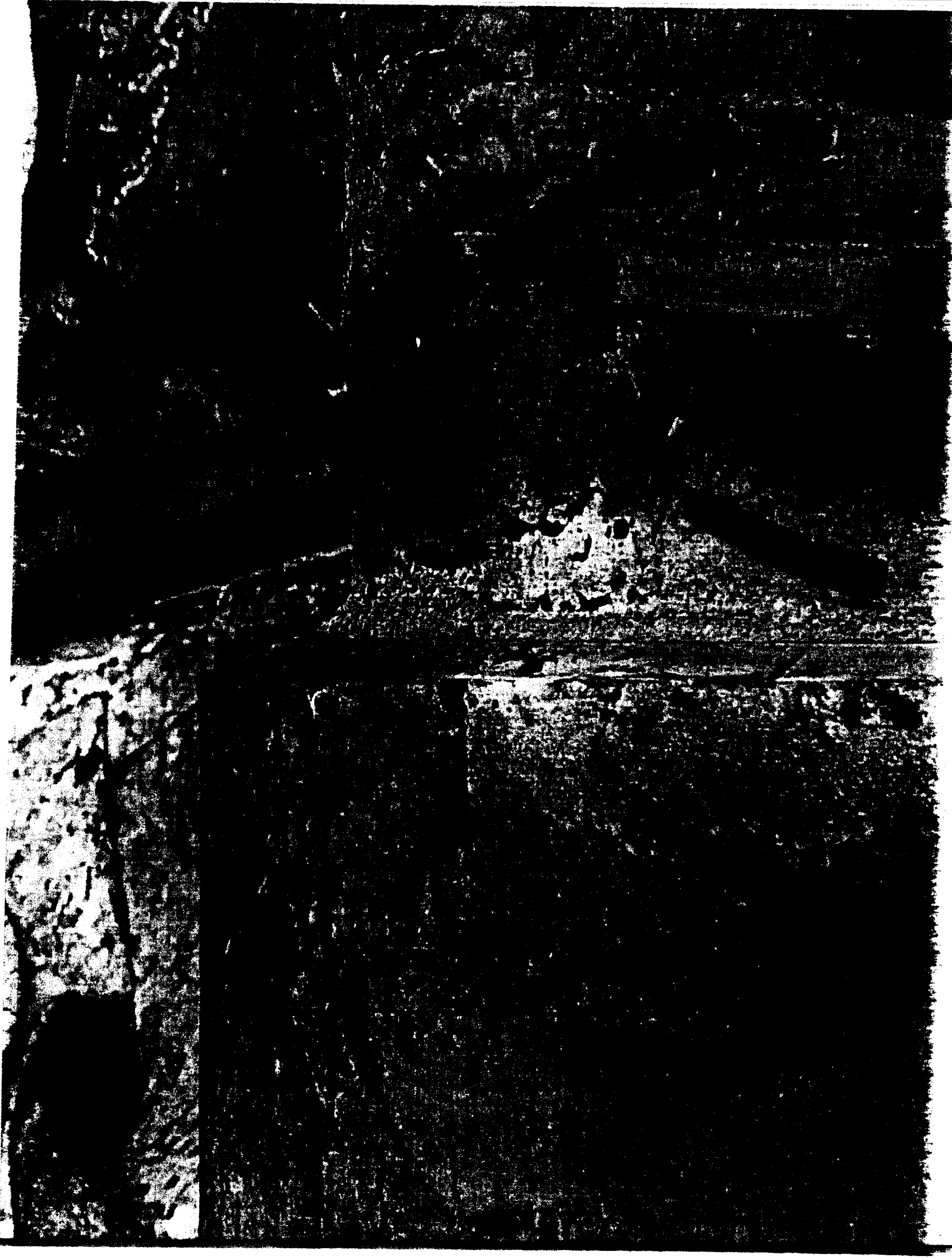
Follow-Up

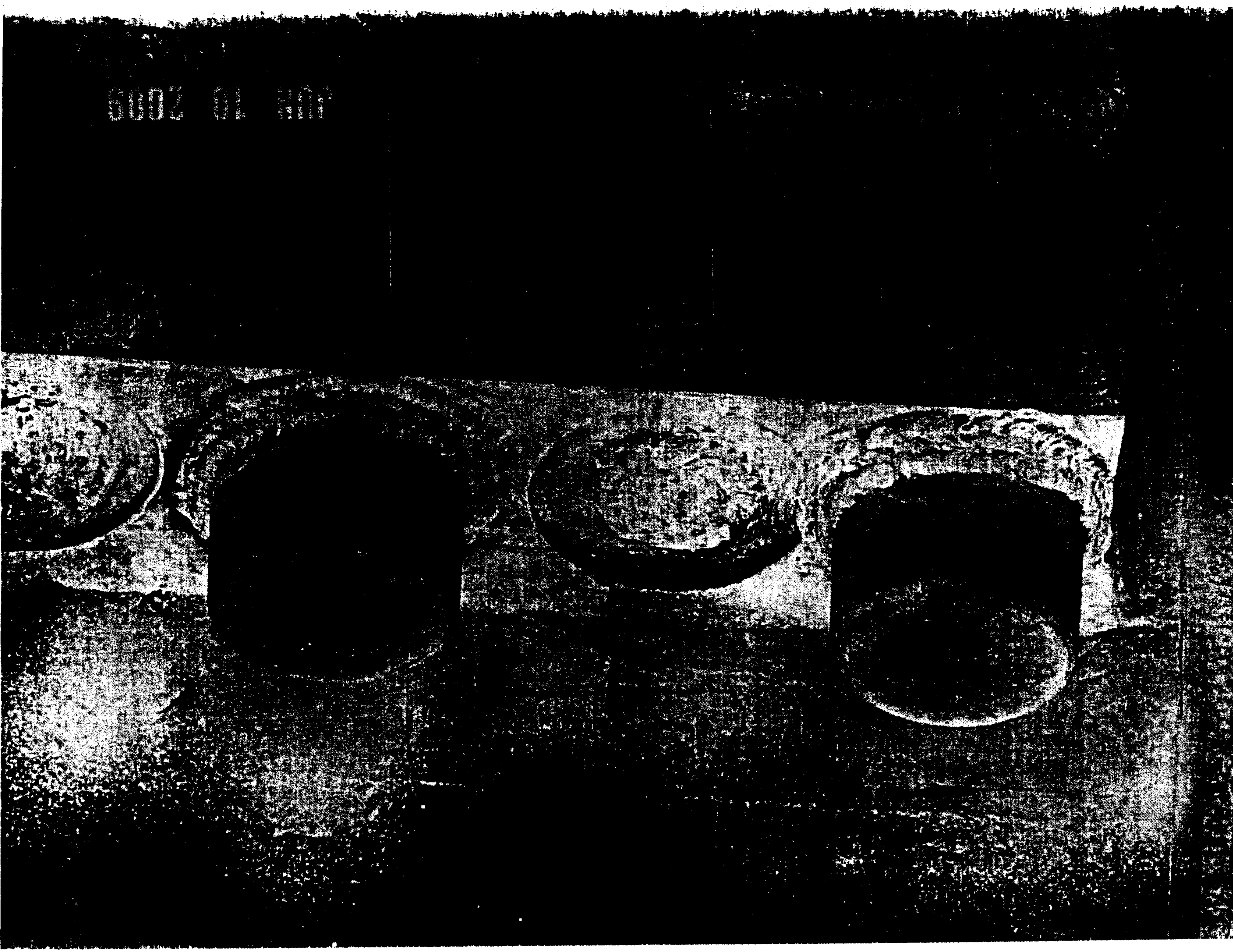
Superior Region Management will track the remedial actions through to completion. The key information from this incident investigation will be communicated company-wide through the Region General Manager at the scheduled Operations Management Committee (OMC) meeting.



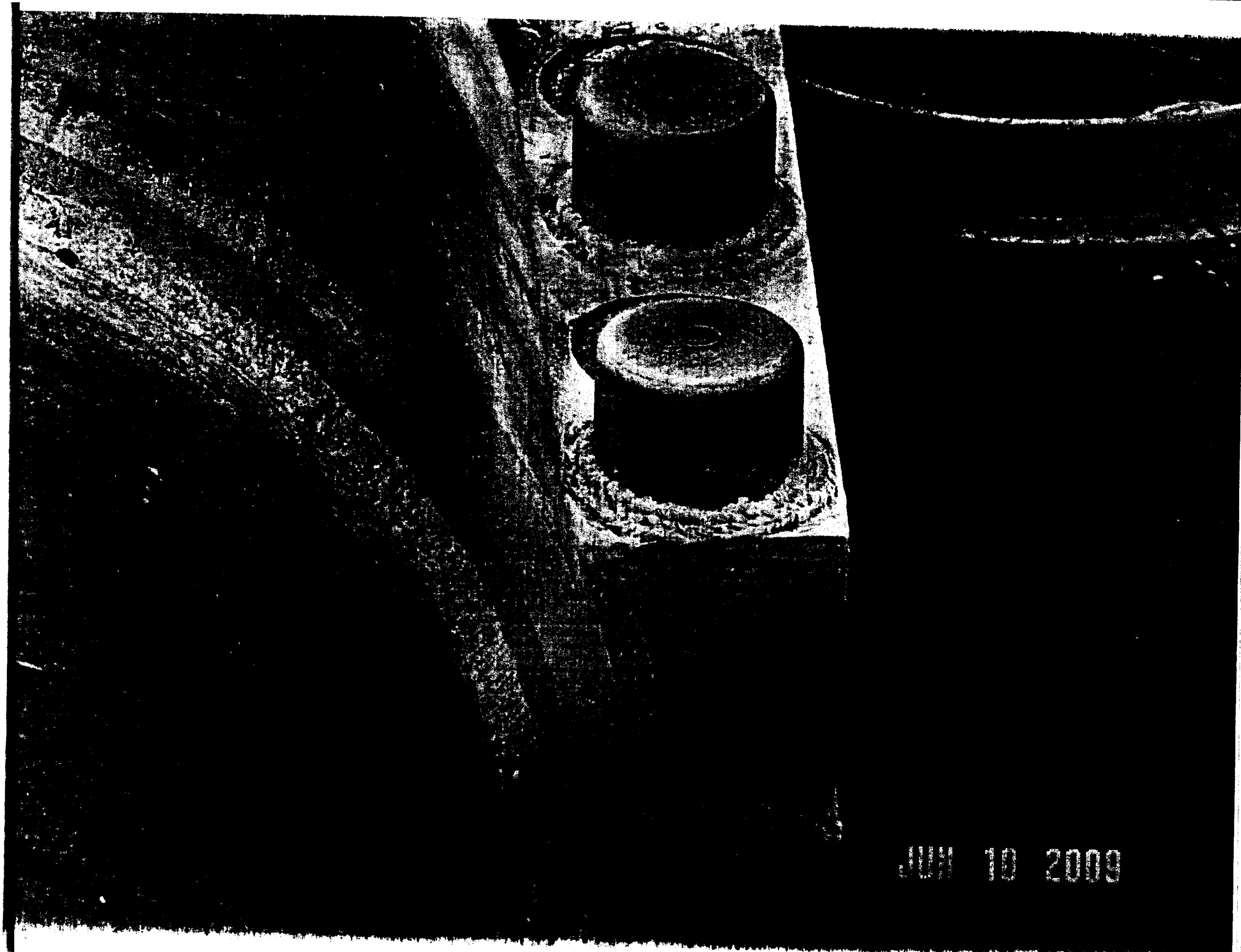

JUN 10 2009



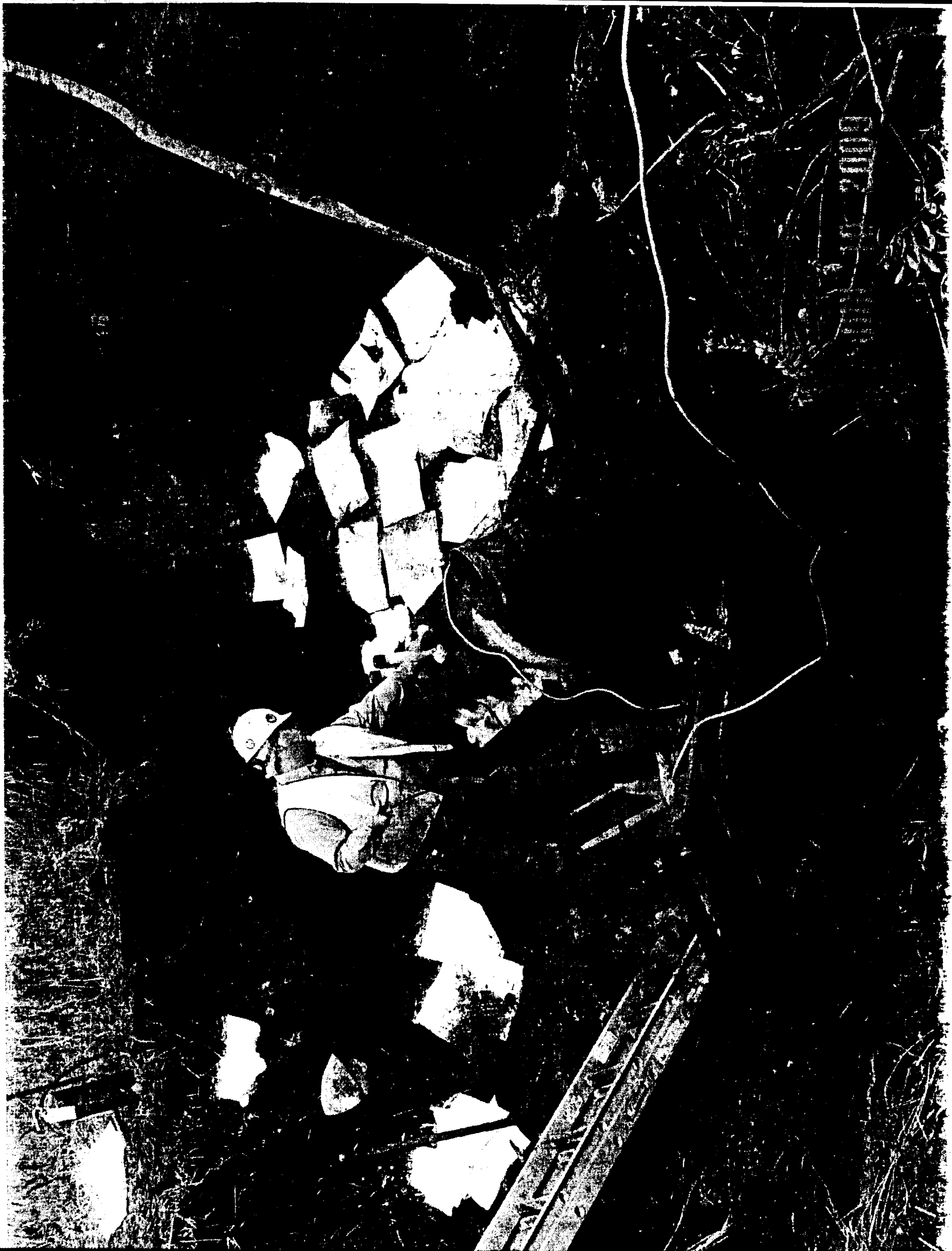


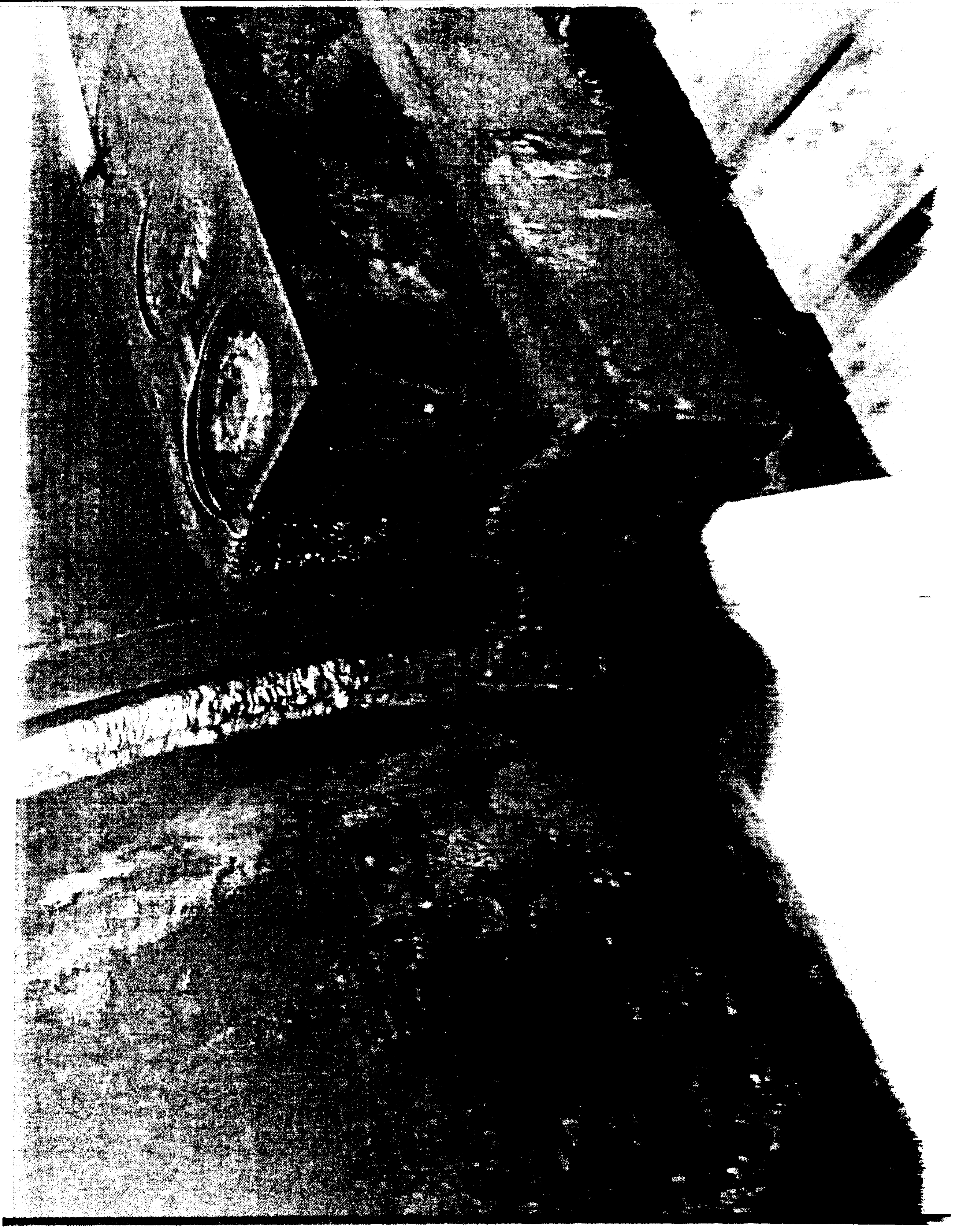

JUN 10 2009

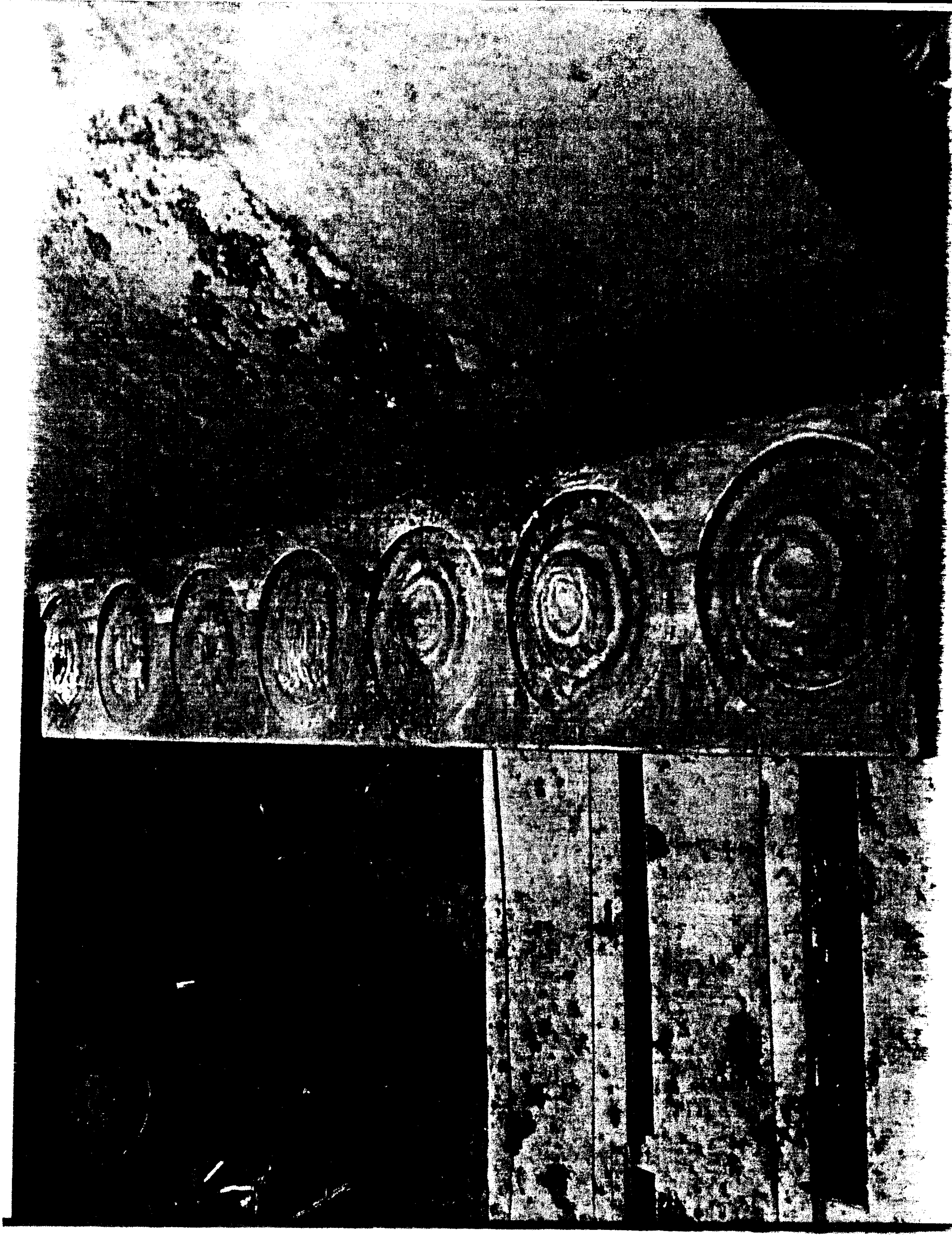

JUN 10 2009


JUN 10 2009


JUN 10 2009







Memorandum

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

Central Region Office

Office of Pipeline Safety

Date: June 25, 2010

Subject: Accident Report: Enbridge Energy Company – Line 61 Pig Trap Sump Release
Superior Terminal – Douglas County, Superior, WI
Crude Oil Release – Pig Sending Trap Sump Overflow
May 21, 2009

From: Brian Pierzina, General Engineer

To: David Barrett, Director Central Region, PHP-300

SUMMARY

At approximately 2:00 p.m. CDT on May 21, 2009, Enbridge Energy Company (Enbridge) experienced a release of crude oil from their Line 61 Pig Sending Trap Sump Tank, at the Superior Terminal, in Superior, WI. The release occurred when the vent valve between the trap and the sump tank was inadvertently left open during remote testing of "isolate" and "de-isolate" commands for Line 61 from the Edmonton Control Center. The crude oil was contained within the terminal containment system. Free product was recovered with vacuum trucks, and contaminated soil was collected and hauled to a landfill facility. Enbridge reported 154 barrels of crude oil were released, with 140 barrels recovered. Total costs associated with the accident were $117,257. There were no injuries, and no ignition. Approximately 700 cubic yards of contaminated soil were removed. The release occurred on Enbridge property, which is designated a high consequence area (HCA) due to population, drinking water, and an unusually sensitive environmental area (OPA, Drinking Water, USA).

ACCIDENT

Enbridge's Edmonton Control Center (CCO) and a Superior Area Electrical Technician were testing isolate and de-isolate commands on Line 61, at the Superior Terminal. These commands would close or open a number of valves at the Line 61 Pig Launch Facility. Two valves on the Pig Sending Trap were initially locked out due to pig loading operations, and required lock removal in order to perform the tests. The Electrical Technician contacted the Pipeline Maintenance (PLM) Team Lead via telephone and received verbal approval to remove the locks/tags from the two valves. The Technician retrieved the keys, removed the locks/tags, contacted the CCO, and gave the Line Operator clearance to issue the commands. The Line

Operator issued the isolate command, at which time a number of valves closed. The Line Operator then issued the de-isolate command, at which time a number of valves opened, including the two which isolated the main line from the pig trap. The Technician was unaware at the time that a vent line valve between the pig trap and sump tank had been left open to provide thermal relief for the pig trap. When the de-isolate command was issued, oil filled the trap, flowed through the vent line, and over-filled the trap sump tank. When the release began, the Technician was investigating an equipment fault at the other end of the station. When he returned to the area, he observed oil flowing out of the trap sump tank, and immediately initiated emergency response operations to stop the release and contain the spill.

INVESTIGATION

Enbridge conducted a thorough internal investigation, including interviews with personnel involved in the accident, and review of applicable procedures. Post-accident drug and alcohol testing was conducted for applicable personnel, and all results were negative. Enbridge provided updates to PHMSA periodically, including the investigation results, and remedial actions that were implemented to prevent a recurrence. The investigation yielded a number of findings related to employee performance, procedural clarity, and unique circumstances associated with the particular facilities involved, that all contributed to the accident to some degree. Enbridge has undertaken steps to address each of the findings.

Enbridge's Line 61 is newly constructed, and some design features are still in the process of being implemented. One of the features at the Superior Terminal Pig Sending Trap is an automated pig launcher system. The system will allow for automated launching of batch pigs from the trap; however the automated feature was not operational at the time of the release, so operations personnel were required to be on-site in order to launch batch pigs, when required. In addition, a permanent thermal relief system for the trap had not been installed at the time of the release, so the interim procedures provided for leaving the vent valve open to the sump, as the method of providing thermal relief for the sending trap facilities. Enbridge indicated these interim procedures did not go through the same review process as the permanent procedure.

Enbridge's investigation revealed that forms associated with Lockout/Tagout (LOTO) operations were not completed as required by their procedures. While the sending trap facility was properly prepared, and the physical steps associated with the LOTO operation were completed as required, neither the LOTO Form or the Pressurized Piping (Valve Positioning) Form were completed by the involved personnel. Either of these forms would have indicated to the Electrical Technician that the vent valve was in the open position, and would need to be closed in order to perform the isolate and de-isolate commands from the CCO. As a result of the investigation, Enbridge determined that the LOTO requirements for group lockout within the Operations and Maintenance Procedures (O&MP) manual are unclear.

FINDINGS

The following factors contributed to the accident:

1. The Technician did not identify the vent valve as open.
2. No Lockout/Tagout Log was completed.
3. The PLM Team Lead issued verbal approval to the technician allowing him to remove the locks without making provisions to verify all valves were closed.
4. No pressure piping isolation form was completed.

CORRECTIVE ACTIONS

As a result of the accident, Enbridge identified a number of corrective actions that would be taken:

1. Ensure applicable employees are trained and understand that systems such as lockout/tagout, hazard assessment, and safe work permits are mandatory.
2. Review and modify operations and maintenance procedures associated with group lockout/tagout, and re-train employees as necessary.
3. Revise the interim trap operation procedure in order to reflect details from the permanent procedure.
4. Review the trap sump system design and operation to determine if improvements can be made related to overfill prevention and detection.
5. Complete installation of the permanent thermal relief system.
6. Reinforce with applicable personnel that preparation of the pressure piping isolation form is mandatory.
7. Review thermal overpressure training requirements for pipeline maintenance workers.

Enbridge has stated that the Superior Region management would follow the progress of the corrective actions through to completion, and that lessons learned from the accident would be shared company-wide.

EXHIBITS

1. NRC Report #906291 – 05/21/2009
2. Enbridge Form 7000-1 Written Accident Report – Entered 04/13/2010
3. Enbridge Incident Investigation Report – 08/07/2009

ENBRIDGE

Incident Investigation Report

Line 61 Trap Sump Overflow Release on May 21, 2009

Enbridge LRS #2370

Final Report Date: August 7, 2009

Summary of Events

On May 21, 2009 the Edmonton Control Center (CCO) and a Superior Area Electrical Technician were testing isolate and de-isolate commands on Line 61 at Superior Terminal. These commands would close or open a number of valves at the Line 61 Pig Launch Facility. Two valves on the sending trap were locked out due to pig loading operations and required lock-out device removal to facilitate the test. The Electrical Technician requested and received approval via phone from the Pipe Line Maintenance (PLM) Team Lead to remove the locks/tags. The Technician then obtained the keys from the local MCC building where they were stored, removed the locks/tags, contacted CCO, and gave the Line Operator clearance to issue the isolate and/or de-isolate commands. The Line Operator then issued the isolate command at which time a number of valves closed. The Operator then issued the de-isolate command at which time a number of valves opened, two of which were the mainline valves isolating the trap from the mainline. At the time, unknown to the Technician, the vent line that leads from the trap to the sump tank was open. When the mainline valves opened, oil filled the trap and overfilled the trap sump tank. The two mainline valves were closed, and the flow subsided. The technician performed initial containment actions and engaged the Incident Command system.

What Resulted

The event resulted in approximately 150 barrels of oil escaping. All oil was contained within existing terminal containment structures. Company and contract personnel immediately responded and began initial cleanup efforts involving the removal of contaminated soil and skimming of oil off of the terminal containment ponds. All free product and contaminated soil was removed from the site over the next several days and no residual environmental impacts are anticipated.

Root Causes

There are a number of root causes that led up to this incident. Had any one of these factors been removed, the incident may not have occurred.

1. The Technician did not identify the vent valve as being open.
2. The permanent thermal relief system had not yet been installed on the trap.
3. The Control Center Operator does not see the status of the vent valves
4. No Lockout/Tagout Log was filled out in this case.
5. Lockout/Tagout requirements for group lockout within the O&MP manuals are unclear.
6. The interim procedure that was in place for this operation did not go through the same review process as the permanent procedure.
7. The PLM Team lead issued approval to the technician allowing him to remove the locks without making provisions to verify all valves were closed.

8. No pressure piping isolation form was completed for this work.
9. The vent valve (interim thermal relief) was open, when it could have been closed as the trap was mostly empty.

Remedial Actions

There are a number of actions that will be undertaken as a result of this incident.

1. The Superior Region Safety Coordinator will review the lockout / tagout system training, hazard assessment system training, and safe work permit system training and ensure that it is understood by applicable employees that these systems are mandatory.
2. The Superior Region Safety Coordinator will re-train the Superior PLM Crew on Lockout / Tagout procedures with emphasis on the use of the lockout/tagout log.
3. The Senior Safety Coordinator will review the O&MP group lockout / tagout section for adequacy and compliance with OSHA regulations, particularly surrounding group lockout, key control, personal locks, and removal of locks. Appropriate changes will be made to the procedures and affected employees will receive training on the revised procedure.
4. The Superior Region Supervisor of Regional Engineering and Services will revise the interim trap operation procedure to reflect details from the permanent procedure.
5. The Superior Region Supervisor of Regional Engineering and Services and the Power and Controls Group will conduct a review of the trap sump pump system design and operation, including the system control logic, to evaluate if any changes would improve overfill protection and detection.
6. The Major Projects Facilities Group will complete installation of the permanent thermal relief system.
7. The mandatory need to complete the pressure piping isolation form will be reinforced at the next Regional Environmental, Health, and Safety Committee Meeting.
8. The Supervisor, Regional Engineering and Services will work with the Company's Training Coordinator to review the thermal overpressure training requirements for Pipeline Maintenance Workers.

Follow-Up

Superior Region Management will track the remedial actions through to completion. The key information from this incident investigation will be communicated company-wide through the Region General Manager at the scheduled Operations Management Committee (OMC) meeting.

EXHIBIT 1

NRC REPORT #906291

EXHIBIT 2

7000-1 ACCIDENT REPORT FORM
#20090170-11646 (Supplemental/Final)

EXHIBIT 3

ENBRIDGE – INCIDENT INVESTIGATION REPORT AUGUST 7, 2009

ENBRIDGE

LOCK OUT TAG OUT FORM (LOTO)

Valve #	Lock #	Initial Status O / C	Shut-down Status O / C	Time	Initial	Locked at Equip	Locked at MCC	Re-Pressurize Status – O / C	Time	Initial	Comments

FINAL CHECK BEFORE DE-PRESSURIZING

Are all sealing devices (valves) in proper position?		☐	YES
Person in Charge of work	Signed:		

FINAL CHECK BEFORE RE-PRESSURIZING

Are all sealing devices (valves) in proper position?		☐	YES
Person in Charge of work	Signed:		

Plan → Isolate → Depressurize → Test for LEL's Vapors etc → Start Work

Work Complete → Check for Tools & Personnel → Confirm Sealing Device Positions → Re-pressure

Lock Removal Authorization Form

Removal of a personal lock by anyone other than the person it belongs to or an equipment lock without proper authorization will be subject to immediate suspension and possible termination of employment. The intent of this Form is to ensure that the necessary steps have been taken, before lock removal, in order to safeguard personnel. This Form addresses both personal and equipment locks.

PERSONAL LOCK REMOVAL (TO BE FILLED OUT, ONLY IF A PERSONAL LOCK HAS TO BE REMOVED)				
DATE:	LOCK OUT PROCEDURE #		LOCK #	
Name of the Lock Owner:				
Reason for Lock Removal:				
LOA Responsible for lock removal:				
			PHONE #	
NOTE: All of the following questions must be answered:				
Step 1	Was a thorough search of the job site conducted by the Team Lead and Area Operator to ensure that the worker is no longer there?	❑ YES	Must be a "Yes"	A thorough search must be made by both.
Step 2	Was the lock owner able to be contacted? (Attempts should be made)	❑ YES	❑ NO	Phone #: Time:
Step 3	Did the lock owner give verbal permission to remove the lock?-	❑ YES	❑ No	If so, enter time of verbal authorization and initial. Time: Initial:
Step 4	Did the Supervisor give his/her permission to remove the lock? (Print name) Name of Supervisor:	❑ Yes	Must be a "Yes"	If so, enter time of verbal authorization and initial. Time: Initial:
EQUIPMENT ISOLATION LOCK REMOVAL (To be filled out, only if an equipment lock has to be removed)				
Date:	Isolation #		Lock #	
Reason for Lock Removal:				
Shift Team Lead Responsible For lock Removal				
			Phone #	
NOTE: All of the following questions must be answered:				
Step 1	Is the isolation ready to be removed?	❑ Yes	Must be a "Yes"	All permits have been signed off.
Step 2	Did the Supervisor give his/her permission to remove the lock? (Print name of Supervisor) Name of Supervisor	❑ Yes	Must be a "Yes"	If so, enter time of verbal authorization and initial. Time: Initial:

1.0 PURPOSE

Is to provide guidance on the prevention of accidental releases of hazardous energy while working on equipment

2.0 SCOPE

This work procedure:

- Applies to all workers and equipment at Enbridge facilities.
- Will be used in conjunction with standard and specific equipment procedures:

3.0 PRECAUTIONS

Equipment Isolation Procedure has been developed for the required tasks and has been reviewed by all workers involved

4.0 PREREQUISITES

Persons performing lockout must have completed the Control of Hazardous Energy training.

Locks must be identified with the appropriate identification tag and be used when working on equipment.

5.0 ASSOCIATED STANDARDS/FORMS

- Equipment Isolation Standard
- Book 2- 07 Electrical Safety
- Book 3- 06 Pipe Repair and Modifications
- Job Planning Template
- Routine Maintenance on Open System Planning Template
- Nuclear Source Isolation
- Blinding

6.0 Isolation Requirements **(This section will require engineering/technical input for Enbridge's Requirements to use/install this equipment) Section is currently located in the procedural document as well as the program**

All energy isolation points for equipment to be opened or worked on must be locked and tagged by an authorized employee/LOA. The authorized employee/LOA must be indentified on the Lockout/Tagout Form.

Equipment is considered to be deemed at zero hazardous energy when all of the following items can be met:

Energy/Hazard	Equipment Condition	Verification by
Explosive gases	<10% LEL for hot work	Operations / PLM to verify with Gas detector.
Pressure	At atmospheric pressure	Verify drain/vent free and clear
Electricity	Zero voltage	Test by pushing start button or using meter

Thermal	Cool to close to ambient temperature	Check temperature in field
Thermal PSV	Drain systems before PSV's and thermal reliefs are isolated.	Review systems and complete shut down and isolation procedure.
Mechanical (e.g. springs, coil)	Moving parts immobilized	Immobilization device in place, locked and tagged
Radiation	Close & lock shutter	Contractors with CNSC licence.
Toxic Chemical	< 8-hour OEL (RPE Table)	Measure by Drager or other approved detector. If not testable in advance, higher exposures shall be assumed

6.1 Positive Isolation Methods

All equipment will be positively isolated from the event of hazardous energy being released or introduced into the space during the task. Methods used to provide positive isolation.

6.1.1 Double block and bleed (DB&B)

- DB&B is positive isolation by closing two in-line valves and opening a drain or vent valve in the line between the two closed valves. If one of the block valves leak, it is not considered positive isolation.
- By closing the Engineered DB&B valve and opening the valve body drains.
- The bleed valve must be:
  - Secured in the open position to atmosphere while work is ongoing.
  - Checked while open if it could create an explosive, toxic or asphyxiating atmosphere.

6.1.2 Blinding/Blanking

During blinding (cold work) the following conditions for equipment must be achieved:

- Liquid free
- At atmospheric pressure
- LEL as low as reasonably practical

6.1.3 Electrical Lock Out

- The risks of electrical arc flash are to be managed during positive isolation.
- Refer to Book 2, Section 7.

6.1.4 Rotational Lock Out

Reciprocating Compressors – flywheel locks to be in place when working on compressor cylinder internals.

6.2 Positive Isolation not met

If positive isolation cannot be achieved or the risks of exposure to the worker are less than other isolation methods, the following can be done:

- Single Isolation of Piping
  - Supervisory approval is required
  - Valve Integrity must be confirmed

- Pressure gauges checked to confirm isolation
- Vents checked to verify that the valves are holding
- Ignition sources are eliminated

- Alternative Isolation Procedures
  - Utilized as a last resort if all of the above are not reasonable
  - General Manager and Supervisor must approve
  - A detail procedure to mitigate and reduce hazards must be developed

7.0 ISOLATION PROCEDURES

There are many factors that come into play when a piece of equipment is isolated. All workers involved in maintenance or repairs on equipment must always be vigilant to ensure the integrity of the isolation and to immediately point out any problems that may arise. Items that will need to be considered prior to isolating equipment may include:

- Lockout Authority (LOA)
  - Identify it is required to use a LOA
  - Identify who that person(s) will be
  - Identify how shift changes will be coordinated
- Use of Hasps/Scissor Clamps
  - Whenever possible, use a hasp/scissor clamp on isolation points to accommodate the option of multiple work groups isolating the same points.
  - Whenever possible, use a hasp/scissor clamp when isolating equipment with equipment locks for extended time frames. When work groups need to complete work on that equipment, they can leave the equipment lock in place and add the appropriate lockout locks.
- Piping:
  - Whenever possible, utilize a double block and bleed method.
  - When a double block and bleed method is not practical, the system is to be blanked or blinded.
  - Single isolation should only be utilized when the hazards have been mitigated to an acceptable level identified by hazard assessment.
  - When single isolation is the only option available on a hazardous system, an Engineering review must be completed. Prior to work proceeding, the General Manager/Designate and Supervisory approval is required.
- Electrical:
  - Electrical Isolation must be completed as per Book 2, High and Low Voltage Procedures in Tab 7.
  - Electrical Isolation may only be completed by employees who are authorized and trained per Book 2, Tab 7.

Once the equipment has been shut down, taken out of service and/or put into its isolation state, the following processes outlines how employees would perform typical isolations.

Conventional Lockout for One Employee
When one employee will be isolating equipment to perform work, the following example is provided to give guidance on a typical procedure:

Example – An authorized employee who will be isolating, preparing and working alone on a system.

Completing the Isolation

- Determine what type of isolation will need to take place and the hazards involved in the preplanning (i.e.: piping, mechanical, electrical, chemical, gravity, etc.)
- Print out the standardized Equipment Specific Procedure Form for the particular piece of equipment if it is available. If not, start with a blank sheet.

Note: Another tool such as Maximo or a job planning template is acceptable to use in lieu of the Equipment Specific Procedure form, as long as it includes similar information.

- Ensure that all of the sections of the Equipment Specific Procedure form are filled out if using it.
- Print out the standardized Lockout/Tagout Form.
- Fill in Section 1 of the Lockout/Tagout Form from the information on the Equipment Specific Procedure form or equivalent.
- Record each isolation point from the Equipment Specific Procedure form or equivalent in Section 2 of the Lockout/Tagout Form.
- Obtain the required number of locks and tags to carry-out the isolation.
- The employee can either apply a lockset, keeping the key with them (and ensuring that the remaining locks cannot be utilized), as they are working alone; or the employee can install individual/personal locks at each isolation point and maintain the keys.
- Appropriate tags must be placed on the locks at the isolation points. In this case, photo ID tags, combination hasp/tags, or personal lockout tags with the appropriate information filled out could be applied.
- If a lockset is utilized, record the lock set identifying information (ie: department and lockset number) on the Lockout/Tag out Form.
- Place the appropriate lock and tag on each isolation point (energy isolating device) in the field (fill out the appropriate information and initial the Lockout Form as each isolation point is completed).
- Verify that the isolated equipment is at a zero energy state and initial the Lockout/Tagout Form.
- If a lockset is utilized, ensure that the remaining locks cannot be accessed.

Removing the Isolation

- Ensure the work is complete.
- De-isolate each isolation point by removing its associated lock and tag. (Initial the "tag removed by" box beside each isolation point on the Lockout/Tag out Form once it has been de-isolated and not before). Remove any blinds/safety grounds.
- Document removal of equipment on the Lockout/Tag out Form

- Return all locks and tags to their appropriate storage location for reuse.
- Sign off the Lockout/Tag out Form.
- File the Forms for future reference.
- Depending on the equipment, when returning equipment to service operations shall follow commissioning procedures:
    - Pre -start up equipment checks
    - Pressure check for leaks
    - Special purging procedures may apply.

Work not completed during the shift:
If an employee is not able to complete the work activities on their shift, they must ensure the equipment is isolated with equipment locks.

Option 1

- The employee on the first shift will remove all of the lockout locks from the isolation points and apply the equipment locks in their place with the appropriate equipment isolation tags.
- When the employee returns to complete the work, they must then remove all of the equipment locks and replace them with lockout locks with appropriate tags.
- The employee must verify that the equipment is still energy free and all documentation must be completed.

Option 2

- The employee on the first shift will apply the lockout lockset at a group lockout procedure, which will include having a LOA sign off on the Lockout out Form and applying the necessary personal locks.
- The two LOAs would change out their personal locks for each shift responsibility.
- The worker completing the work would apply their personal lockout lock to the lockbox.
- The employee must verify that the equipment is still energy free and all documentation must be completed.

Group Lockout

When two or more employees will be isolating equipment to perform work, the following examples are provided to give guidance on typical procedures:

Group Lockout without a lockbox system:
This system may be beneficial when there are two or more authorized employees and a minimal number of isolation points.

Example – A mechanic and an electrician will be working on a component of the system together.

Completing the Isolation

- Determine what type of isolation will need to take place and the hazards involved in the preplanning (i.e.: piping, mechanical, electrical, chemical, gravity, etc.)
- Print out the standardized Equipment Specific Procedure form for the particular piece of equipment if it is available. If not, start with a blank sheet.

Note: Another tool such as Maximo or a job planning template is acceptable to use in lieu of the Equipment Specific Procedure form, as long as it includes similar information.

- Ensure that all of the sections of the Equipment Specific Procedure Form are filled out, if using it.
- Print out the standardized Lockout/Tagout Form.
- Fill in Section 1 of the Lockout/Tag out Form from the information on the Equipment Specific Procedure for or equivalent.
- Record each isolation point from the Equipment Specific Procedure form or equivalent in Section 2 of the Lockout/Tag out Form.
- Obtain the required number of locks and tags to carry-out the isolation.
- Place the appropriate equipment on each isolation point.
  - Apply a hasp
  - Have each employee apply a red lockout personal lock on the hasp
  - Each lockout personal lock is equipped with either a Photo ID tag or personal lockout tag
  - Each employee keeps their own key
- Fill out the appropriate information and initial the Lockout Form as each isolation point is completed.
- Verify that the isolated equipment is at a zero energy state and initial the Lockout/Tagout Form.
- Complete the lower portion of Section 2 of the Lockout/Tagout Form after ensuring that all information is correct.

Locksets are not allowed to be used under this application. If the locksets are utilized, this would fall under the group lockout procedure with a lockbox application (see procedure below).

Removing the Isolation

- Ensure the work is complete.
- De-isolate each isolation point by removing its associated lock and tag. (Initial the "tag removed by" box beside each isolation point on the Lockout/Tag out Form once it has been de-isolated and not before). Remove any blinds/safety grounds.
- Document removal of equipment on the Lockout/Tag out Form
- Return all locks and tags to their appropriate storage location for reuse.
- Sign off the Lockout/Tag out Form.
- File the Forms for future reference.
- When returning equipment to service, operations shall follow commissioning procedures:
  - Pre -start up equipment checks
  - Pressure check for leaks
  - Special purging procedures may apply.

Work not completed during the shift:
If an employee is not able to complete the work activities on their shift, they must ensure the equipment is isolated with equipment locks.

Option 1

- The employee on the first shift will remove all of the lockout locks from the isolation points and apply the equipment locks in their place with the appropriate equipment isolation tags.
- When the employee returns to complete the work, they must then remove all of the equipment locks and replace them with lockout locks with appropriate tags.
- The employee must verify that the equipment is still energy free and all documentation must be completed.

Option 2

- The employee on the first shift will apply the lockout lockset at a group lockout procedure, which will include having a LOA sign off on the Lockout out Form and applying the necessary personal locks.
- The two LOAs would change out their personal locks for each shift responsibility.
- The worker completing the work would apply their personal lockout lock to the lockbox.
- The employee must verify that the equipment is still energy free and all documentation must be completed.

Group Lockout with a lock box system:
This system may be beneficial when there are two or more authorized employees and multiple numbers of isolation points, multiple employees, or multiple work groups.

Example – department authorized workers will be isolating equipment for a work group, but will not be performing work themselves on the system. An example of this would be for a PLM crew working on an open system at a terminal. In this case, the terminal may assign equipment owners (i.e. Electricians) to isolate equipment and apply equipment locks and appropriate tagging prior to the LOA for the PLM applying lockout locks to protect employees. The LOA for the PLM then must apply a lockout lock at each equipment lock isolation point to ensure the group lockout is complete for the protection of the workers.

Completing the Isolation:

- Determine what type of isolation will need to take place and the hazards involved in the preplanning (i.e.: piping, mechanical, electrical, chemical, gravity, etc.)
- Print out the standardized Equipment Specific Procedure form for the particular piece of equipment if it is available. If not, start with a blank sheet.

  Note: Another tool such as Maximo or a job planning template is acceptable to use in lieu of the Equipment Specific Procedure form, as long as it includes similar information.
- Ensure that all of the sections of the Equipment Specific Procedure Form are filled out, if using it.
- Print out the standardized Lockout/Tagout Form.
- Fill in Section 1 of the Lockout/Tagout Form from the information on the Equipment Specific Procedure for or equivalent.
- Record each isolation point from the Equipment Specific Procedure form or equivalent in Section 2 of the Lockout/Tag out Form.
- The LOA obtains the required number of lockout locks and tags to carry-out the isolation.
- Record the required information on each of the equipment isolation tags
- Each equipment owner can now complete the equipment isolation procedure as directed (applying blue equipment locks with a hasp/scissor clamp on the isolation points they are responsible for)
- Record the identifying information on the Lockout/Tagout Form.
- The LOA applies a group lockout tag to each lockout lockset lock

- Record the lock set identifying information (ie: department and lockset number) on the Lockout/Tag out Form.
- Place the appropriate lockout lockset lock and group lockout tag on each isolation point (energy isolating device) in the field (fill out the appropriate information and initial the Lockout Form as each isolation point is completed).
- Where an equipment isolation lock was applied, the LOA must apply a lockout lockset lock and tag to the hasp/scissor clamp for a work group to complete work on a system.
- Verify that the isolated equipment is at a zero energy state and initial the Lockout/Tagout Form.
- Complete the lower portion of Section 2 of the Lockout/Tagout Form after ensuring that all information is correct. The LOA/area operator must ensure that all isolation points are secure before signing this section, and a double check is recommended.
- If employees in a work group would like to verify isolation, this must be accommodated.
- Retain a copy of the Lockout/Tag out Form with the lockbox where the work is being performed.
- Place the unused lockset locks, lockset key and/or individually keyed different locks keys in the lock box.
- The LOA will then place their personal lock and tag on the front latching mechanism of the lockbox.
- Each authorized worker who will be working on the isolated piece of equipment must install their personal lock and a photo ID tag/Personal Lockout Tag on the lock box.
- Each member of the working crew maintains control of their key to the personal red lock they applied.

Note: Only employees completing work on the isolated equipment will be permitted to install a personal lockout lock on the lock box. Each authorized employee that applies a personal lockout lock is accepting that the equipment is appropriately locked out. The LOA will accommodate any request to for verification.

Removing the Isolation:

- Ensure that all permits are signed off, the work is complete and personal locks have been removed as well as any blinds / safety grounds.
- The LOA removes their personal lockout lock last from the lock box and can now remove the key(s).
- The LOA de-isolates each isolation point by removing its associated lock/tag/equipment.
- Initial the lock removed by box beside each isolation point on the Lockout/Tag out Form once it has been de-isolated
- The equipment owner is then notified that they can release the equipment isolation by removing the equipment locks.
- Return all locks and tags to their appropriate storage location for reuse.
- Sign off the Lockout/Tag out Form.
- File the Forms for future reference.
- When returning equipment to service, operations shall follow commissioning procedures:
    - Pre -start up equipment checks
    - Pressure check for leaks
    - Special purging procedures may apply.

Work not completed during the shift:

If the work group is not able to complete the work activities on their shift, they must ensure the equipment is isolated with equipment locks, utilize shift change out procedures, or utilize the LOA.

Option 1 – Equipment is still down/taken apart/in need of repair and another work group will not be completing work or will not need to access the equipment until work can be completed:

- The LOA may leave the equipment in an isolated state with the lockout locks from the lockset.
  - All other personal locks must be removed from the lockbox
  - The LOA must make the appropriate notifications to affected employees that may be impacted by the equipment
  - Appropriate contact information for the LOA must be left with affected employees
  - Must be documented on the Lockout/Tagout Form
- Return of workers to completed work on system
  - The LOA must re-verify that the equipment is still isolated appropriately
  - A new Lockout/Tag out Form will be utilized with all verification boxes appropriately noted
  - Workers must be given to opportunity to re-verify equipment
  - All workers must reapply their personal lockout lock and tag to the lockbox.

Option 2 - If the work group is not able to complete the work activities on their shift and another work crew is coming on to relieve the original group:

- A LOA must be assigned to each shift and noted on the Lockout/Tag out Form
- As each employee from the first shift leaves the site, they must remove their personal lock and tag from the lockbox.
- Both LOAs must be onsite to coordinate the shift change.
- The LOA from the first shift will remove their personal lockout lock and tag from the front of the lock box.
- The LOA from the second shift will then apply their personal lockout lock and tag to the front of the lockbox.
- Each employee, including the LOA for the second shift, must be provided with the opportunity to re-verify isolation.
- Each employee for the second shift then applies their personal lockout lock and tag to the lockbox.

Option 3 - If the work group is not able to complete the work activities on their shift, and the equipment will be utilized by other work groups:

- Ensure that all components are returned to operational status
- The LOA will remove all of the lockout locks for the lockset from isolation points.
- If the equipment will need to be "held" until work can be completed, or for another work groups, the LOA will apply equipment locks to the isolation points.
- It is the next work group's responsibility to complete the appropriate isolation procedure prior to resuming or completing any work on that system. The work group will be required to follow all of the steps in the above procedures.

Group Lockout with a Satellite lockbox system:

This system may be beneficial when there are multiple work groups, each with many employees or contractors working on equipment with multiple isolation points. This system would also work well on projects such as tank cleaning where a main lockbox is kept in the terminal office, and multiple groups are completing work at various times.

Example – Multiple work groups are going to be working on a major pipeline repair involving multiple PLM crews, Electricians, Mechanics, and Contractors. If a single lockbox system was utilized, it would have numerous locks, and become confusing to control. In this case, the option of utilizing satellite lock boxes would be beneficial.

Completing the Isolation:

- Determine what type of isolation will need to take place and the hazards involved in the preplanning (i.e.: piping, mechanical, electrical, chemical, gravity, etc.)
- Identify an overall LOA (Master LOA) to take responsibility for the isolation of equipment.
- Identify each work group and attach a work group list to the Lockout/Tag out Form for field use.
- Each working group must identify a LOA (Work Group LOA) to take responsibility for the protection of every employee in their work group. This will be documented on the Lockout/Tag out Form
- Print out the standardized Equipment Specific Procedure form for the particular piece of equipment if it is available. If not, start with a blank sheet.

  Note: Another tool such as Maximo or a job planning template is acceptable to use in lieu of the Equipment Specific Procedure form, as long as it includes similar information.

- Ensure that all of the sections of the Equipment Specific Procedure Form are filled out, if using it.
- The Master LOA will print out the standardized Lockout/Tag out Form
- Fill in Section 1 of the Lockout/Tagout Form from the information on the Equipment Specific Procedure for or equivalent.
- Record each isolation point from the Equipment Specific Procedure form or equivalent in Section 2 of the Lockout/Tag out Form.
- Each working group will provided with the standardized Lockout/Tagout Form for review with employees and to keep a copy with their lockbox(s).
- The Master LOA obtains the required number of equipment locks and tags to carry-out the isolation.
- Record the required information on each of the equipment isolation tags Record the lock set identifying information (ie: department and lockset number) on the Lockout/Tag out Form.
- Each equipment owner, if utilized, can now complete the equipment isolation procedure as directed (applying blue equipment locks with a hasp/scissor clamp on the isolation points they are responsible for)
- Where an equipment isolation lock was applied, the Master LOA must apply a lockout lockset lock and Master LOA tag to the hasp/scissor clamp for a work group to complete work on a system.
- Record the identifying information on the Lockout/Tagout Form.
- The Master LOA will place the appropriate lockout lockset lock and Master LOA lockout tag on each remaining isolation point in the field (fill out the appropriate information and initial the Lockout Form as each isolation point is completed).
- Verify that the isolated equipment is at a zero energy state and initial the Lockout/Tagout Form.
- Complete the lower portion of Section 2 of the Lockout/Tagout Form after ensuring that all information is correct. The Master LOA must ensure that all isolation points are secure before signing this section, and a double check is recommended.
- If employees in a work group, or a Work Group LOA would like to verify isolation, this must be accommodated. Each group that makes the request will utilize their individual work group's Lockout/Tag out Form
- Retain a copy of the Lockout/Tag out Form with the lockbox where the work is being performed.
- Place the unused lockset locks, lockset key and/or individually keyed different locks keys in the lock box.

- The Master LOA will then place their personal lockout lock and a Master LOA tag on the front latching mechanism of the lockbox.
- Each Work Group LOA will then add an individual lockout lock for their crew with a group tag to the lock box.
- The Work Group LOA will then take their key for the individual lockout lock back to their crew.
- The Work Group LOA will place their key for the individual lockout lock on the Master Lockbox into a Satellite lockbox for their crew.
- The Work Group LOA will then place a personal lockout lock and tag on the front latching mechanist of the satellite lockbox.
- Each authorized worker of the work crew who will be working on the isolated piece of equipment must install their personal lock and a photo ID tag/Personal Lockout Tag on the satellite lock box.
- Each member of the working crew maintains control of their key to the personal red lock they applied.

Note: Only employees completing work on the isolated equipment will be permitted to install a personal lockout lock on the lock box. Each authorized employee that applies a personal lockout lock is accepting that the equipment is appropriately locked out. The Master LOA will accommodate any request to for verification.

Removing the Isolation

- When the entire project is completed for a work group, each Work Group LOA will sign off on the work group list attached to the Lockout/Tag out Form.
- Ensure that all permits are signed off, the work is complete and personal locks have been removed as well as any blinds / safety grounds.
- Employees remove their locks and tags from the satellite lockbox.
- The Work Group LOA removes their personal lockout lock last from the satellite lock box and can now remove the key(s).
- The Work Group LOA will then proceed to the Master Lockbox and remove their personal lockout lock from it.
- The Master LOA will then remove their personal lockout lock and tag from the master lockbox and access the key(s).
- The Master LOA de-isolates each isolation point by removing its associated lock/tag/equipment.
- Initial the lock removed by box beside each isolation point on the Lockout/Tag out Form once it has been de-isolated
- The equipment owner is then notified that they can release the equipment isolation by removing the equipment locks.
- Return all locks and tags to their appropriate storage location for reuse.
- File the Forms for future reference.
- When returning equipment to service, operations shall follow commissioning procedures:
    - Pre -start up equipment checks
    - Pressure check for leaks
    - Special purging procedures may apply.

Work not completed during the shift:

If the work group is not able to complete the work activities on their shift, they must ensure the equipment is isolated with equipment locks, utilize shift change out procedures, or utilize the LOA.

Option 1 – Equipment is still down/taken apart/in need of repair and another work group will not be completing work or will not need to access the equipment until work can be completed:

- The Master LOA may leave the equipment in an isolated state with the lockout locks from the lockset.
    - All other personal locks must be removed from the lockbox
    - The Master LOA must make the appropriate notifications to affected employees that may be impacted by the equipment
    - Appropriate contact information for the LOA must be left with affected employees
    - Must be documented on the Lockout/Tagout Form
- Return of workers to completed work on system
    - The Master LOA must re-verify that the equipment is still isolated appropriately
    - Workers must be given to opportunity to re-verify equipment
    - All workers must reapply their personal lockout lock and tag to the lockbox(s) per the above procedure.

Option 2 - If the work group is not able to complete the work activities on their shift and another work crew is coming on to relieve the original group:

- Two Master LOA must be assigned, one for each shift, and noted on the Lockout/Tag out Form, as well as two Work Group LOA assigned if a crew will be continuing work on the next shift.
- As each employee from the first shift leaves the site, they must remove their personal lock and tag from the lockbox.
- The Work Group LOA from the first shift will remove their personal lockout lock and tag from the front of the satellite lock box. The key to the individual lock on the Master Lockbox is left in the satellite lockbox
- The Work Group LOA from the second shift will then apply their personal lockout lock and tag to the front of the satellite lockbox.
- The Master LOA from the first shift will remove their personal lockout lock and tag from the front of the master lockbox. The locks for the Work Group LOAs will be left in place.
- The Master LOA for the second shift will then apply their personal lockout lock and Master LOA tag to the front of the satellite lockbox.
- Each employee, including any LOA for the second shift, must be provided with the opportunity to re-verify isolation.
- Each employee for the second shift then applies their personal lockout lock and tag to the satellite lockbox.

Complex Lockout Guarantee of Isolation (Lockouts Over Distances)

The distance factor can add challenges to the lockout program. This system may be beneficial when isolation points are located where it may not be practical for a LOA to complete the isolation. For this type of work, the work groups would follow procedures listed above in group lockout, and then utilize one of the following options for the "off site" valves:

- Option 1
    - The LOA can be sent to the location to complete the lockout.
    - The LOA could either utilize locks and tags from the lockset, a new lockset with group tags, or individual locks with group tags.
    - The LOA would isolate the appropriate equipment.

- The LOA would brings the key(s) back to the lockbox at the site, and place them in the lockbox with any other key(s). If the original lockset is utilized, there would be no keys to add.
- The isolation is verified and the work can begin

- Option 2
  - The LOA would become a Master LOA and would make arrangements with an employee at the site to ensure the valves are isolated appropriately.
  - The employee at the site would be set up as a Remote Site LOA.
  - A copy of the Equipment Specific Form and the Complex Group Lockout Guarantee of Isolation Form would be provided to the Remote Site LOA at the facility.
  - The Master LOA would have a Lockout/Tag out Form indicating all of the isolation points, including the remote location.
  - The Master LOA would have a copy of the Complex Group Lockout Guarantee of Isolation Form to document communication with the Remote Site LOA.
  - The Remote Site LOA would have a copy of the Complex Group Lockout Guarantee of Isolation Form to document the isolation and communication with the Master LOA
  - The Remote Site LOA completes the isolation lockout utilizing either a lockout lockset or individual lockout locks and a LOA tag that identifies the Master LOA and provides contact information for both LOAs.
  - The key(s) must be locked in a secured location identifying that it belongs to the complex group lockout.
  - Remote Site LOA verifies the lockout
  - Once the lockout is completed, the Remote Site LOA at the remote site(s) communicates to the Master LOA:
    - The equipment that was locked out
    - The status that the equipment was locked out in (open/closed)
    - The information on what lockout locks were utilized
    - Provides the time of the guarantee of isolation
  - The Master LOA will then accept the guarantee of isolation if it is correct and has been verified.
  - The Master LOA will document on the Lockout/Tag out Form/Complex Group Lockout Guarantee of Isolation Form that they have accepted the guarantee of isolation from the remote location.
  - When the equipment is released, the Master LOA will notify the Remote Site LOA that they are ready for the equipment to be relieved from isolation.
  - The Remote Site LOA will inform the Master LOA when the release from isolation is completed.
  - The release of isolation will then be documented on the Lockout/Tagout Form/Complex Group Lockout Guarantee of Isolation Form.

Potential Scenarios Related to Contractors:

- Contractor is involved in the work with a work group or employee
  - There are a couple options for accommodating contractors in the lockout procedure.

- Option 1 – Each contract employee is required to add personal lockout lock in conjunction with a filled out Personal Lockout Tag. They will then add this to the lockbox and offered the same option to complete their own verification.
- Option 2 – One member of each contracting firm is required to add a personal lockout lock in conjunction with a filled out Personal Lockout Tag. The individual will then apply the lock to the lockbox; take the key back to their crew and their crew is responsible for following their company lockout requirements.

- An equipment owner (i.e. Electrician) will need to isolate equipment for a contractor, but will not be performing work with the contractor.
  - The equipment owner would utilize equipment locks in conjunction with a hasp to isolate the appropriate equipment. It would then be the contractor's responsibility to follow company lockout procedures to ensure the protection of each contract employee working on the system.

<u>Tagout</u>

In the event a piece of equipment cannot be locked out, a tag out method can be utilized. All of the above procedures will be utilized in the same manner. The only variations will be as follows:

- A tag will be installed at the site where the isolation has occurred
- The tag will include all required information
- The bottom portion of the tag will be removed
- If working alone, the bottom portion of the tag will remain with the authorized employee
- If working with a lockbox, the bottom portion of the tag(s) will be placed in the lockbox.
- When de-isolating the equipment, the tag bottom(s) will be utilized to ensure all equipment is returned to service.

The Control of Hazardous Energy (Lockout/Tagout)

1.0 PURPOSE

The purpose of this Standard is to establish a system of ensuring that equipment is isolated, tagged and locked out so that it can be safely worked on without injuring personnel. It also establishes working solutions to exceptions and/or problems that may be encountered when dealing with isolations. This Standard provides personnel with the procedure for placing, recording, storing and safeguarding equipment isolations.

2.0 SCOPE

The scope of this document encompasses lock out for electrical and pipeline equipment isolation at the Enbridge Pipelines Inc. facilities. It is intended that this document will be utilized by all Enbridge employees and Contractors.

3.0 BACKGROUND

The Standard is written to support health & safety compliance. This Standard is not a stand-alone document, and it is recommended that this Standard be read and applied in conjunction with applicable sections of the, Canada Labor code documentation, Code of Federal regulations, OSHA Lockout tag Standard Canadian Electrical Code, and, applicable Enbridge procedures.

4.0 REFERENCES

- Canada Labor code Part II
- Alberta Occupational Health & Safety Act, Regulation and Code
- Canada Electrical Code
- United States –Code of Federal regulations , Title 29 Labor, Part 1910.147
- ANSI Z244.1 – (R2008), Control of Hazardous Energy Lockout/Tagout and Alternative Methods

5.0 DEFINITIONS

Affected Employee: Is an employee whose job requires him/her to operate or use equipment on which servicing or maintenance is being performed

Authorized Employee- is an employee who is assigned to perform hazardous energy control.

Blanking – A process of inserting a physical barrier through a cross-section of pipe so that materials are prevented from flowing past that point.

Blinding – A process of disconnecting a pipe and attaching a physical barrier to its end so that materials are prevented from flowing out of the pipe.

Breaker Lock - is a device that is specifically designed to mechanically connect to an electrical circuit breaker knob. The breaker lock can accept a hasp/ scissor clamp in order to prevent the breaker knob from being moved to the energized position.

De-Energized – Disconnected from all energy sources and not containing residual or stored energy.

Double Block and Bleed – A process that involves utilizing a three-valve system where a pipe has two closed valves and an open drain valve positioned between them so that material is prevented from flowing and is re-directed in case of a valve leak.

Energized is connected to an electrical energy source or containing residual or stored energy.

Energy Isolation Device is a mechanical device that physically prevents the transmission or release of energy from electrical, mechanical, hydraulic, pneumatic or other energy sources.

The Control of Hazardous Energy (Lockout/Tagout)

Equipment Isolation Procedure - is a document that determines the sequence and steps required to complete the specific isolation. An approved isolation procedure will be required prior to completion of all high voltage isolations.

Group Lockout – Any lockout involving two or more employees.

Hasp/Scissor clamp - is mechanical device that is inserted into the handle mechanism of a breaker lock or disconnect switch handle. Once installed, the scissor is capable of ensuring the breaker lock or disconnect switch handle cannot be moved from the "open", "off" or "de-energized" position. The scissor has multiple holes that can accept various locks. All locks have to be removed from the Hasp/ Hasp/ Scissor clamp assemble before the scissor can be opened and removed from the breaker lock or switch handle.

Hazardous Energy – Any electrical, mechanical hydraulic, pneumatic, chemical, nuclear, gravity or energy that could cause injury to personnel.

High Voltage Equipment Owner - Electrical Department.

High Voltage Clearance of Isolation– is a written or verbal guarantee that is always recorded in writing to confirm that a particular piece of equipment is isolated.

Interlock – A device or system whereby the status of one control or mechanism allows or prevents the operation of another.

Isolated - means the normal sources of energy have been disconnected or controlled.

Isolation - is the securing of one or more isolation points using a pre-defined system.

Isolation Point - is the point where the energy isolation device is installed.

Lock Out Authority (LOA) – a primary authorized employee who is designated by the Area Manager /Supervisor for group lockout purposes. They are authorized Enbridge electricians or non – electrical workers who will exercise the primary responsibility for the implementation and coordination for the overall lockout of hazardous energy sources for the equipment to be serviced.

- Master LOA – an authorized employee who is designated for a group lockout purposes involving a Satellite Group Lockout or a Complex Group Lockout Procedure
- Work Group LOA – An authorized employee who is designated as the LOA for a working group during a Satellite Group Lockout Procedure
- Remote Location LOA – An authorized employee who will be performing a lockout at a remote location from the work being performed. The employee will perform this lockout through communication with the Master LOA at the site.

The high voltage LOA is under the custody and control Electrical Department. They are authorized Enbridge electricians, journeyman electricians, who are trained in the electrical isolation and lock out of the equipment that is to be de-energized, discharged or isolated.

Lock Out - is the act of placing a lock out device on an energy isolation device, in accordance with an established procedure, ensuring that the energy isolation device and the equipment being controlled cannot be operated until the lock out device is removed.

Lock Box - is a container that securely stores the lock key(s) and unused locks so that they are secure until the equipment is ready for de-isolation.

Lock Out Device - is a device that utilizes a positive means to hold an energy isolation device in the safe position so that the machine or equipment cannot be energized. (Example: keyed locks and Hasp/ Hasp/ Scissor clamps)

Lockout/Tagout Form - is the document containing the details regarding equipment isolations, associated isolation procedure #, equipment status, lockout details and person responsible for completion of the equipment isolation and de-isolation.

The Control of Hazardous Energy (Lockout/Tagout)

Lock Set - is a pre-defined number of locks that are engraved with identifier and keyed alike and grouped on a steel ring that is stamped with the common lock number.

Safe Work Permit - is controlled and issued by Enbridge Operations Department or the pipeline maintenance Department.

System Owners – The department that is the controller of the system involved in the isolation. These departments may include PLM, Terminal, Electrical, Mechanical, Major Projects and Engineering. Operations Department for the Terminal systems may include tanks, valves, pumps, etc. on terminal property. The Pipeline Maintenance department may include the main pipelines into the respective Terminals. The Electrical Department may include switchgear buildings, and electrical substations. The Mechanical Department may include valves and pumps at stations. The system owners are responsible for completing a lockout/tagout with blue locks for any other worker or work groups.

Tagout – The placement of a tagout device on an energy isolating device, in accordance with an established procedure, to indicate that the energy isolating device and the equipment being controlled may not be operated until the tagout device is removed.

Tagout Device – A prominent warning device, such as a tag and a means of attachment, which can be securely fastened to an energy isolating device in accordance with an established procedure, to indicate that the energy isolating device and the equipment being controlled mat not be operated until the tagout device is removed.

Verification check – Process for ensuring that equipment is in a zero energy state.

Voltage Levels:

- Low voltage – (Canada) 750 VAC, United States 600VAC and less
- High voltage – Over (Canada) 750 VAC, United States 600VAC

Note: These voltage definitions are intended for isolation purposes only and may differ from definitions located in other government Standards.

Zero energy state - is when all electrical energy and potential or stored energy to and within electrical equipment is removed.

6.0 GENERAL

The lockout program covers the servicing and maintenance of machines and equipment in which the unexpected energization or start up of the machines or equipment, or release of stored energy could cause injury to employees. Employees are required to appropriately isolate equipment prior to performing any work.

Each employee working during a lockout must be afforded the same level of protection. Before working on the equipment, the worker, in addition to working under a Safe Work Permit, must attach his/her personal lock and an identification tag to the appropriate lock box or isolation point to ensure that the equipment cannot be de-isolated before he/she is finished the work on this equipment.

Equipment/energy sources will always be locked out when possible. If it is not possible to lockout a piece of equipment or an energy source, a tagout procedure will be followed. Interlocks are not allowed to be utilized in lieu of lockout or tagout procedures.

The Control of Hazardous Energy (Lockout/Tagout)

Equipment that is connected by plug and cord is not required to be locked out if the employee can maintain control of the plug end. When an employee is working on equipment connected by plug and cord, it must be unplugged prior to any work being completed.

In the event an energy device is not capable of being locked out, it is acceptable to utilize a tagout system. The tags would be placed at each isolation point in lieu of a lockout device.

6.1 Forms/Written Documentation

There are multiple forms and documents that must be completed and maintained as part of the lockout program. The documents will include equipment specific procedures, lockout/tagout form, blanking and blinding procedure form, abandoned lock removal procedure, and the periodic inspection form.

6.1.1 Equipment Specific Procedures

The equipment specific procedure form will be developed prior to work being completed on equipment being locked out/tagged out. The equipment specific procedure form can be utilized when a procedure has not been developed.

Routine and maintenance activity equipment specific procedures can be utilized through other tools such as Maximo, or other similar maintenance tools. This can be utilized in lieu of filling out the equipment specific procedure form.

6.1.2 Lockout/Tagout Form

The lockout/tagout form is a field tool to ensure that isolation has been completed and verified. In the Lock out Tagout Form, the following information is to be recorded:

- Date – the date that the isolation was started or put together;
- Associated Isolation Points- the valve number. Initial status and shut down status
- Lock set number (if utilizing a lock set)/tag number (if numbering the tags)
- Purpose of the isolation – the reason that the identified equipment is being isolated (it is important to be as specific as possible).
- Lockout Authorities name and signature

6.1.3 Blanking/Blinding Procedure Form

Where equipment is to be isolated by blanking or blinding, this form will be utilized to ensure that all steps are completed.

6.1.4 Abandoned Lock Removal Procedure Form

If a personal lock has been abandoned by the worker, the lock cannot be taken off until all steps on the Abandoned Lock Removal Procedure Form. This form may also be applied when a worker has lost a key. The LOA/Supervisor must ensure that:

- The authorized employee who applied the device is not at the facility
- All reasonable efforts to contact the employee have been completed
- The employee is informed of their lock being removed prior to resuming work

The Control of Hazardous Energy (Lockout/Tagout)

6.1.5 Periodic Inspection Form

The company will conduct periodic inspections of the energy control procedures on a regular basis. This will be completed to ensure that the procedure is accurate an adequate, to identify inadequacies, and to ensure that requirements are being followed. The periodic inspection form will be filled out by an authorized employee other than the one(s) performing the lockout. Periodic inspections must be completed on both lockout and tagout applications.

7.0 EQUIPMENT

7.1 Equipment Locks

These locks are blue in color and used to ensure that the energy isolation device at required isolation points is immobilized.

7.1.1 Equipment locks/ department locks

These are individually keyed locks or keyed alike lock sets. Multiple keys may be issued at the discretion of the location.

Equipment lock sets these sets are to be blue on color with a lock set identifier to ensure the lock set cannot be separated.

7.1.2 Equipment locks are to be used for:

- Long term equipment shutdown/ out of service.
- Shutdowns where protection to personnel is not required.
- When authorized worker isolated equipment for another employee or work group, but will not be performing work on that equipment .i.e. an electrician isolates a breaker for a PLM worker.

7.2 Lock out Locks

These locks are red in color, and are used for isolation purposes for worker protection. These locks can be individually keyed, or belong to a lockset meeting company criteria. When a worker is involved in a lockout, the key for their personal lock is to be kept with them at all times. Once a worker has finished working his/her shift, they are to remove their lock immediately and retain it for future use. If they are performing more work on the same equipment the next day, they can re-establish their personal lock at that time. Lock sets are equipment locks that consist of locks that are keyed alike. Lock sets are allowed under group lockout or multiple isolation point applications. They come in sets of between 10 locks or more.

7.2.1 Individually Keyed Locks/Personal Locks

These locks are individually keyed with only one key issued per a lock. Individually keyed locks are to be used for:

- Issuing to employees for personal locks
- Placed on a lockout center for use by individual employees/isolations
- Smaller lockouts where a lockset of ten would not be practical

7.2.2 Lock Set Locks

These are keyed alike with only one key issued per a set. One Lockout Authority must be identified prior to utilizing the lock set system. Any unused locks must be placed in the lockout box with the key. This is so they cannot be utilized on another lockout project. Lockout lock sets are to be used for:

- Larger lockout isolations
- Group lockout activities

Criteria for lockout lock sets:

- A lockset identifier must indicated on the Lockout/Tagout Form
- Must be engraved with a lock set identifier i.e.: crew, department, lock set number.

Locks	**Lock ID Tag Color**	**Key**
Operations equipment lock		Keyed Alike (set) /Different (individual)
Pipeline maintenance equipment lock		Keyed Alike (set) /Different (individual)
Lockout Lock Set		Keyed Alike
Lockout Locks/Personal Locks		Keyed Different

7.3 Tags

An important part of communication in the lockout/tagout standard is tagging locks. It is important to identify the employee that placed the lock and the reason for the lock at all times. Every lock placed system wide will be required to have an appropriate tag on the shank of the lock that identifies the owner. Tags utilized for isolating equipment should have the words, "DANGER DO NOT OPERATE" written on one side with the words, "DANGER - Do Not Remove This Tag – To Do So Without Authority Will Mean Immediate Disciplinary Action.

There are several types of tags that can be utilized, depending on the lock and the purpose.

Types of Tags for Lockout:

7.3.1 Photo ID Tag - All workers at Enbridge facilities, who will be working on or in isolated equipment, will be issued at least one photo ID tag to go along with individually keyed lock(s). At a minimum the tag will include:

- The photo of the employee
- The name of the employee
- The department of the employee
- The phone number of the employee

7.3.2 Personal Lockout Tag - If a worker does not have a photo ID tag, they may fill out an appropriate lockout out tag to go along with individually keyed lock(s). At a minimum this tag will include:

- The name of the employee
- The department of the employee
- The phone number of the employee

7.3.3 Group Lockout Tag – When a system is being locked out for a group lockout, a group lockout tag will be attached to the shank of the lockset lockout lock. At a minimum this tag will include:

- The name of the LOA who applied the lock
- Contact information for the LOA
- The department applying the lock
- The purpose of the isolation

7.3.4 Labeled Lockout Hasps – These are a product that is a hasp with the ability to accommodate up to six locks, and has a tag integrated into the surface. Can be used anywhere a hasp/scissor clamp is required.

7.3.5 Contractor Personal Tag - A contractor applying a lock to the system must have a tag on the individually keyed lock(s). The lockout tag must at a minimum include:

- The name of the employee
- The name of their company
- The phone number of the employee

7.3.6 Lockout Authority (LOA) Tag – The LOA must have their lock/tag identified separately from the other personal locks/tags. This can be accomplished by adding a solid color coded tag in addition to the personal ID tag, or (ideas here on how to identify? – brass tag, etc.)

7.3.7 Tags for Equipment Locks:

When a blue equipment lock is applied, an equipment lock tag will also be applied to identify why the equipment was removed from service. At a minimum this tag will include:

- Name of the employee applying the blue lock
- Reason why equipment was removed from service
- Date of removal from service

A labeled lockout hasp may be used in lieu of an equipment lock tag when an employee is isolating the equipment for another employee or work group, but will not be working on the isolated equipment.

7.3.8 Tagout

When utilizing a tagout system, tags will be placed at the same location where the isolation occurs. The tag must have two parts separated by a perforation, one to remain at the isolation point and the other to stay with the authorized employee or in a lockbox. The tag must include all of the following information:

- The name of the employee/crew

- Contact information for the employee/crew
- Work that is being completed
- Notation that this is a tagout.

7.4 **Hasps/Scissor Clamps**

Anytime an employee is isolating a piece of equipment that another group or employee may also need to isolate, a hasp or scissors clamp will be applied. This is required to ensure that other work groups, employees, contractors can add a lock to protect them or their work group until their work is completed.

7.5 **Color Coding**

Each region may choose to color code the back of the tags or hasps/scissor clamps to show what work group is involved in a lockout. The following chart provides guidance on the color coding system for work groups:

Work Group	Color for the back of Tags or Hasps/Scissors Clamps
Electricians	**Green**
Mechanics	**Yellow**
Terminal Operations	**White/Silver**
PLM	**Blue**
Engineering	**Orange**
Major Projects working on equipment turn over to Operations	**Purple**

7.6 **Lock Boxes**

7.6.1 The lock boxes are located where the work is being performed

7.6.2 The front lock box latch is to only be used by the LOA

7.6.2 In the event a large number of workers will be involved in a lockout, hasps or scissor clamps can be utilized to increase the number of personal lock points.

7.6.3 WARNING: Tampering with a lock box is a serious offense and will result in an Incident Report being initiated with subsequent disciplinary action.

8.0 Isolation Requirements **(This section will require engineering/technical input for Enbridge's Requirements to use/install this equipment) Section is currently located in the procedural document as well as the program**

The Control of Hazardous Energy (Lockout/Tagout)

All energy isolation points for equipment to be opened or worked on must be locked and tagged by an authorized employee/LOA. The authorized employee/LOA must be indentified on the Lockout/Tagout Form.

Equipment is considered to be deemed at zero hazardous energy when all of the following items can be met:

Energy/Hazard	Equipment Condition	Verification by
Explosive gases	<10% LEL for hot work	Operations / PLM to verify with Gas detector.
Pressure	At atmospheric pressure	Verify drain/vent free and clear
Electricity	Zero voltage	Test by pushing start button or using meter
Thermal	Cool to close to ambient temperature	Check temperature in field
Thermal PSV	Drain systems before PSV's and thermal reliefs are isolated.	Review systems and complete shut down and isolation procedure.
Mechanical (e.g. springs, coil)	Moving parts immobilized	Immobilization device in place, locked and tagged
Radiation	Close & lock shutter	Contractors with CNSC licence.
Toxic Chemical	< 8-hour OEL (RPE Table)	Measure by Drager or other approved detector. If not testable in advance, higher exposures shall be assumed

8.1 Positive Isolation Methods

All equipment will be positively isolated from the event of hazardous energy being released or introduced into the space during the task. Methods used to provide positive isolation.

8.1.1 Double block and bleed (DB&B)

- DB&B is positive isolation by closing two in-line valves and opening a drain or vent valve in the line between the two closed valves. If one of the block valves leak, it is not considered positive isolation.
- By closing the Engineered DB&B valve and opening the valve body drains.
- The bleed valve must be:
  - Secured in the open position to atmosphere while work is ongoing.
  - Checked while open if it could create an explosive, toxic or asphyxiating atmosphere.

8.1.2 Blinding/Blanking

During blinding (cold work) the following conditions for equipment must be achieved:

- Liquid free
- At atmospheric pressure
- LEL as low as reasonably practical

8.1.3 Electrical Lock Out

- The risks of electrical arc flash are to be managed during positive isolation.
- Refer to Book 2, Section 7.

8.1.4 Rotational Lock Out

Reciprocating Compressors – flywheel locks to be in place when working on compressor cylinder internals.

8.2 Positive Isolation not met

If positive isolation cannot be achieved or the risks of exposure to the worker are less than other isolation methods, the following can be done:

- Single Isolation of Piping
  - Supervisory approval is required
  - Valve Integrity must be confirmed
  - Pressure gauges checked to confirm isolation
  - Vents checked to verify that the valves are holding
  - Ignition sources are eliminated
- Alternative Isolation Procedures
  - Utilized as a last resort if all of the above are not reasonable
  - General Manager and Supervisor must approve
  - A detail procedure to mitigate and reduce hazards must be developed

9.0 Temporary Isolation removal

Good communication and planning are keys to reducing the amount of times that this option will be used, so that the lockbox is rarely modified. There will be times when an isolation point may have to be de-isolated temporarily to perform a test or for some other unforeseen action by manipulating the energy device (i.e. motor rotation test, leak from a valve).

In the event a temporary isolation removal cannot be prevented, the authorized employee/LOA must ensure that the equipment is de-isolated appropriately and re-isolated again if required.

10.0 Abandoned Locks (Removal)

If a personal lock has been abandoned by its owner (worker), and the isolation is ready to be removed, the lock cannot be taken off until the Abandoned Lock Removal Procedure Form is completed.

The Control of Hazardous Energy (Lockout/Tagout)

11.0 New Construction Isolation Turnover

As construction reaches a point where there will be tying into preexisting systems, an isolation turn over package must be developed between operations and the division turning over the equipment.

12.0 Returning Equipment to Service

All equipment shall be inspected to ensure:

- the work is complete.
- the equipment is safe to return to service.
- For larger jobs such as capital projects, a formal pre-startup P&ID line check shall be completed.

13.0 Training

Employees shall be trained on lockout prior to performing a lockout or tagout procedure. Employees will be trained to the level that they are expected to perform at. Employees will complete retraining anytime:

- there is a change in their job assignment
- when there are changes in the equipment that will affect how it is locked out
- when there is a change in the process or energy control procedure
- when a periodic inspection reveals that there are deviations or inadequacies
- on a periodic basis to ensure employees are proficient

13.1 Affected Worker Training

An employee who will not be performing lockout, but whose work operations may be in the area where lockout is being performed will at a minimum be trained on:

- how to identify lockout equipment
- that lockout equipment is not to be tampered with
- a basic overview of the Control of Hazardous Energy program

13.2 Authorized Worker Training

An employee who will be performing lockout will at a minimum be trained on:

- recognition of hazardous energy sources system wide
- the type and magnitude of energy sources system wide
- the methods and means necessary for energy isolation and control
- energy control procedures
- equipment requirements and usage

13.3 Lock Out Authority

An employee who will be performing that task of locking out systems and equipment so that their respective work group can perform work must at a minimum be trained on:

- recognition of hazardous energy sources system wide
- the type and magnitude of energy sources system wide
- the methods and means necessary for energy isolation and control
- energy control procedures
- equipment requirements and usage
- proper documentation
- how to verify isolation/allowing employees to verify isolation
- the responsibilities of their role

14.0 Periodic Inspection

The company will conduct periodic inspections of the energy control program at least annual to ensure that the procedure and requirements of the standard are being followed. The inspection will:

- Be performed by an authorized employee other than the one(s) utilizing the procedure being reviewed
- Be conducted to correct any deviations or inadequacies identified
- Include a review between the inspector and each employee of that employee's responsibilities under the isolation being reviewed

15.0 RECORD KEEPING

15.1 Equipment Specific Procedures must be stored on site for a minimum of 1 year.

15.2 The completed Lockout/Tagout Forms must be stored on site for a minimum of 1 year.

15.3 Blanking/Blinding Procedure Forms must be stored on site for a minimum of 1 year.

15.4 Abandoned Lock Removal Procedure Forms must be stored on site for a minimum of 1 year.

15.5 Periodic Inspection Forms must be stored on site for a minimum of 1 year.

Lockout/Tagout Equipment Specific Procedure

Machine				
Energy Sources	**Electric**	**Pneumatic**	**Hydraulic**	**Other**
Equipment Needed				
Lockout Procedure				

Scope	This scope covers any servicing or maintenance of the above listed equipment. The equipment must be completely shut down to perform any servicing or maintenance.
Purpose	To provide specific guidance to authorized personnel on how to de-energize, isolate and reenergize the equipment, to prevent the unexpected start-up or release of energy that could result in injury or death.
Authorization	The designated Lockout Authority is . Employees working on the equipment may verify the lockout at any point during the process upon request.
Compliance	Failure to comply with established procedures may result in disciplinary action or termination.

Machine Shut Down Process	
Step 1	Notify Affected Employees of the shut down (operators/area personnel)
Step 2	
Step 3	
Step 4	
Step 5	
Step 6	
Step 7	
Step 8	
Step 9	
Step 10	
Step 11	
Step 12	
Step 13	
Step 14	
Step 15	
Step 16	
Step 17	
Step 18	

Machine Release From Lockout/Tagout Process	
Step 1	Inform any employees in the area that equipment will be brought back online
Step 2	Ensure all tools are removed and that all appropriate guards, covers, and other equipment is back in place
Step 3	

Developed On :	Developed By:

Revisions	

Lockout/Tagout Form

SECTION 1 – GENERAL INFORMATION	
Date:	
Equipment Number/ Description:	Associated Isolation Procedure # Written
Purpose of The Isolation:	

SECTION 2 – ISOLATION TAG POINT INFORMATION

	Isolation Point (Description)	Initial Valve Status – Open or Closed	Status During Isolation	Closed Position Verified and Lockout Lock (Red) on Actuator or Hand Wheel by	Isolation of Electrical Equipment (Blue or Red Locks) Placed/Verified by	Lockout Lock (Red) Isolation Placed/ Verified by	Lockout Locks (Red) Isolation Removed By

Notes And/Or Hazards:

Authorized Employee:	Signature:	Date:	Time:
Area Operator/ Technician :	Signature:	Date:	Time:
Lock Out Authority:	Signature:	Date:	Time:

SECTION 3 – REMOVAL OR REPLACEMENT INFORMATION (In the event of a leak/failure/pump installation)

Equipment/Date & Time	Type	Reason/ Explanation	Operator Name & Initial
	❑ Removed ❑ Replaced		
	❑ Removed ❑ Replaced		
	❑ Removed ❑ Replaced		

Notes:

SECTION 4 – DE-ISOLATION & RETURN TO SERVICE

Concern	Status	Notes

Are All Blinds/Grounds Removed?	❑ Yes	❑ No			
Are All Permits Signed Off And All Work Verified To Be Complete?	❑ Yes	❑ No			
Signed Off By Lock Out Authority	Name:		Initial	Date	Time
Are All Locks Removed?	❑ Yes	❑ No			
Is Equipment Ready-For-Service?	❑ Yes	❑ No			
Signed Off By Area Operator/Technician	Name:		Initial:	Date	Time

Legislation

Canada

Canada Labour Code, Part II:

- Canadian Occupational Safety and Health (COSH) regulations

Provincial/territorial occupational health and safety regulations

United States

Code of Federal Regulations (CFR), Title 29 Labor:

- Part 1910.147—Control of Hazardous Energy (Lockout/Tagout)

Definitions

authorized worker—when referring to lockout, a knowledgeable, competent worker who locks or tags equipment in order to service or maintain that equipment.

Responsibilities

Management

Operations managers and site supervisors must ensure:

- correct lockout procedures are followed
- workers are appropriately trained in lockout procedures
- lockout devices are provided at each location

Field Inspections

Operations management must inspect lockout procedures as part of field inspections. In addition, supervisors must conduct routine inspections to ensure appropriate lockout procedures have been established and are being followed.

Requirements

Authorization

Only authorized workers must apply locks and tags.

APLI

Lockout

When servicing and/or maintaining equipment, each worker working on the equipment must place a personal lock and tag on the equipment and verify it is locked out and safe of hazardous energy sources. Each personal lock must have a unique mark or identification tag that identifies the worker.

> ⚠**WARNING:** Do not work on equipment until it has been tested and confirmed inoperative (see *06-03-01 Locking Out Equipment-Standard Procedure*).

Personal Locks

Personal locks (i.e., one lock and one key) are required to protect workers performing work on equipment. At least one personal lock must be used for each trade working on the locked-out equipment.

NOTE: Operations management will issue approved locks to authorized workers.

Keys

Only one key is issued for each personal lock. Do not duplicate keys.

NOTE: Operations management may keep master keys for personal locks, but must follow emergency lock removal procedures when using them.

Department Locks

NOTE: Department locks are required to protect equipment, and must not be used for personal protection.

Lockout Stations

Lockout stations must be available wherever multiple lockout work could take place (e.g., at station switchgear or terminal facilities).

Tags

Each lock or lock-box must have a tag identifying the name of the worker responsible for the lockout.

When locks cannot be physically installed to isolate equipment, tags alone can be used. Operations management must be notified of those instances where locks cannot be used and efforts made to make changes to allow locks to be used.

Other Lockout Equipment

Lengths of chain, or the equivalent, must be available for locking out valve handles and similar equipment.

Records

CAN

Field Location Personal Lock Log

Operations management must maintain a log of all locks assigned to field locations for use as personal locks.

ENBRIDGE

PRESSURE PIPING ISOLATION/RE-PRESSURIZING
Valve Position Tracking Form

Purpose - The purpose of this form is to document the correct positioning of valves to ensure all are in the appropriate position prior to de-pressurizing and re-pressurizing the piping system.

Scope - This form is intended to be utilized when the pipeline system is being pressurized or de-pressurized in the following situations:

- Operation of scraper traps
- Isolation of piping to complete piping tie-ins
- Any operation that might result in an oil leak if valves are left in an incorrect position (i.e., small bore piping modifications / sump work / strainers and filters, etc.)
-

Note: this is not intended to be used in situations such as Pressure Transmitter calibrations etc.

How to use this form
This form will provide a record of the operation of each valve involved in the work. A list of the valves to be operated and their order of operation will be placed in the "Isolation Procedure Steps" section. After each valve or group of valves is operated, the worker will indicate the time the action was completed and initial that the valve was opened or closed. Prior to operating the final valve to either vent or re-pressurize, this form will be reviewed with the Assigned Person in Charge of the Work to confirm that all valves are in the proper position.

General Information			
Station:		**Date:**	
Description of piping being isolated (i.e. Line 4 receiving trap)			
Nature of Work and Reason:			

Assigned person in charge of work:		
Name	**Signature**	**Time**

Workers		
Person(s) Working on Equipment	**Signature**	**Time**

ENBRIDGE

Seq#	**Isolation Procedure Steps** Make a list of all valves that will be operated and in what order they will be turned (include vent and drainage valves). Attach piping schematics if available. Confirmation of valve position as described in this list shall be the final step before operating the last valve.	Lock #	Initial Valve Status O / C	Shutdown Valve Status O / C	Time	Initials	Locked at MCC	Locked at Equip	Re-Pressurize Status O / C	Time	Initials
Example	Trap isolation valve (R2.1) to be closed		C								

Appropriate PPE & Equipment?	☐	YES
Isolation Procedure Steps Reviewed & Approved?	☐	YES

FINAL CHECK BEFORE DE-PRESSURIZING

Are all sealing devices (valves) in proper position?	☐	YES
Assigned Person in Charge of work	Signed:	

FINAL CHECK BEFORE RE-PRESSURIZING

Are all sealing devices (valves) in proper position?	☐	YES
Assigned Person in Charge of work	Signed:	

Plan → Isolate → Depressurize → Test for LEL's Vapors etc → Start Work

Work Complete ← Check for Tools & Personnel ← Confirm Sealing Device Positions ← Re-pressurize

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122

Form Approved
OMB No. 2137-0047

U.S. Department of Transportation
Research and Special Programs Administration

ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date jun 16,2009

No. 20090170 -- 11646
(DOT Use Only)

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov.*

PART A – GENERAL REPORT INFORMATION

Check one or more boxes as appropriate:
☐ **Original Report** ☒ **Supplemental Report** ☒ **Final Report**

1. a. Operator's OPS 5-digit Identification Number (if known) / 11169 /
2. b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if known) / /
   c. Name of Operator ENBRIDGE ENERGY, LIMITED PARTNERSHIP
   d. Operator street address 119 N 25TH STREET E
   e. Operator address SUPERIOR DOUGLAS WI 54880
   City, County, State and Zip Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident
   / 1400 / (hr.) / 05 / (month) / 21 / (day) /2009/ (year)

3. Location of accident
   (If offshore, do not complete a through d. See Part C.1)
   a. Latitude: 46° 41' 6" Longitude: -92° 3' 35"
   (if not available, see instructions for how to provide specific location)
   b. SUPERIOR DOUGLAS
   City, and County or Parish
   c. WI 54880
   State and Zip Code
   d. Mile post/valve station ● or survey station no. ○
   (whichever gives more accurate location)
   0

4. Telephone report
   / 906291 / (NRC Report Number) / 05 / (month) / 21 / (day) /2009 (year)

5. Losses *(Estimated)*

Public/Community Losses reimbursed by operator:

Public/private property damage	$ 0
Cost of emergency response phase	$ 0
Cost of environmental remediation	$ 0
Other Costs	$ 0
(describe)	

Operator Losses:

Value of product lost	$ 700
Value of operator property damage	$ 0
Other Costs	$ 116557
(describe)	CLEANUP/ENV CONSULTANT
Total Costs	$ 117257

6. Commodity Spilled ● Yes ○ No
   (If Yes, complete Parts a through c where applicable)
   a. Name of commodity spilled WESTERN CANADIAN SELECT
   b. Classification of commodity spilled:
   ○ HVLs /other flammable or toxic fluid which is a gas at ambient conditions
   ○ CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditions
   ○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
   ● Crude oil

c. Estimated amount of commodity involved :
● **Barrels**
○ **Gallons (check only if spill is less than one barrel)**

Amounts:
Spilled : 154
Recovered: 140

CAUSES FOR SMALL SPILLS ONLY (5 gallons to under 5 barrels) : *(For large spills [5 barrels or greater] see Part H)*

○ **Corrosion** ○ **Natural Forces** ○ **Excavation Damage** ○ **Other Outside Force Damage**
○ **Material and/or Weld Failures** ○ **Equipment** ○ **Incorrect Operation** ○ **Other**

PART B – PREPARER AND AUTHORIZED SIGNATURE

EMILY JURGENS
(type or print) Preparer's Name and Title

(715) 394-1547
Area Code and Telephone Number

EMILY.JURGENS@ENBRIDGE.COM
Preparer's E-mail Address

Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Code and Telephone Number

PART C – ORIGIN OF THE ACCIDENT (Check all that apply)

1. Additional location information
   a. Line segment name or ID 61
   b. Accident on Federal land other than Outer Continental Shelf ◡ Yes ● No
   c. Is pipeline interstate? ● Yes ◡ No

Offshore: ◡ Yes ● No *(complete d if offshore)*
d. Area ________ Block # ________
State / / or Outer Continental Shelf ☐

2. Location of system involved (*check all that apply*)
   ☒ Operator's Property
   ☐ Pipeline Right of Way
   ☒ High Consequence Area (HCA)?
   Describe HCA OPA/USA/DRINKING WATER

3. Part of system involved in accident
   ◡ Above Ground Storage Tank
   ◡ Cavern or other below ground storage facility
   ● Pump/meter station; terminal/tank farm piping and equipment, including sumps
   ◡ Other *Specify:* ________
   ◡ Onshore **pipeline**, including valve sites
   ◡ Offshore **pipeline**, including platforms

*If failure occurred on **Pipeline**, complete items a - g:*

a. Type of leak or rupture
   ◡ Leak: ◡ Pinhole ◡ Connection Failure *(complete sec. H5)*
   ◡ Puncture, diameter *(inches)* ________
   ◡ Rupture: ◡ Circumferential – Separation
   ◡ Longitudinal – Tear/Crack, length *(inches)* ________
   Propagation Length, total, both sides *(feet)* ________
   ◡ N/A
   ◡ Other ________

b. Type of block valve used for isolation of immediate section:
   Upstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve
   Downstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve

c. Length of segment isolated ________ ft

d. Distance between valves ________ ft

e. Is segment configured for internal inspection tools? ◡ Yes ◡ No

f. Had there been an in-line inspection device run at the point of failure? ◡ Yes ◡ No ◡ Don't Know
   ◡ Not Possible due to physical constraints in the system

g. If *Yes*, type of device run (*check all that apply*)
   ☐ High Resolution Magnetic Flux tool Year run: ________
   ☐ Low Resolution Magnetic Flux tool Year run: ________
   ☐ UT tool Year run: ________
   ☐ Geometry tool Year run: ________
   ☐ Caliper tool Year run: ________
   ☐ Crack tool Year run: ________
   ☐ Hard Spot tool Year run: ________
   ☐ Other tool Year run: ________

4. Failure occurred on
   ◡ Body of Pipe ◡ Pipe Seam ● Scraper Trap
   ◡ Pump ◡ Sump ◡ Joint
   ◡ Component ◡ Valve ◡ Metering Facility
   ◡ Repair Sleeve ◡ Welded Fitting ◡ Bolted Fitting
   ◡ Girth Weld
   ◡ Other *(specify)* ________

Year the component that failed was installed: / 2007 /

5. Maximum operating pressure *(MOP)*
   a. Estimated pressure at point and time of accident: 400 *PSIG*
   b. MOP at time of accident: 1490 *PSIG*
   c. Did an overpressurization occur relating to the accident? ◡ Yes ● No

PART D – MATERIAL SPECIFICATION

1. Nominal pipe size *(NPS)* / / in.
2. Wall thickness / / in.
3. Specification ________ SMYS / /
4. Seam type ________
5. Valve type ________
6. Manufactured by ________ in year / /

PART E – ENVIRONMENT

1. Area of accident
   ◡ Under pavement ◡ Underground ◡ Inside/under building
   ◡ In open ditch ● Above ground ◡ Under water ◡ Other ________
2. Depth of cover: 36 inches

PART F – CONSEQUENCES

1. **Consequences** *(check and complete all that apply)*

a.

	Fatalities	Injuries
Number of operator employees:	0	0
Contractor employees working for operator:	0	0
General public:	0	0
Totals:	0	0

b. Was pipeline/segment shutdown due to leak? ◡ Yes ● No
   If Yes, how long? ____ days ____ hours ____ minutes

c. Product ignited ◡ Yes ● No d. Explosion ◡ Yes ● No

e. ☐ Evacuation *(general public only)* / / people
   Reason for Evacuation:
   ◡ Precautionary by company
   ◡ Evacuation required or initiated by public official

f. Elapsed time until area was made safe: / 6 / hr. / / min.

2. **Environmental Impact**
   a. Wildlife Impact: Fish/aquatic ◡ Yes ● No
      Birds ◡ Yes ● No
      Terrestrial ◡ Yes ● No
   b. Soil Contamination ● Yes ◡ No
      If Yes, estimated number of cubic yards: 700
   c. Long term impact assessment performed: ● Yes ◡ No
   d. Anticipated remediation ◡ Yes ● No
      If Yes, check all that apply: ☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife
   e. Water Contamination: ◡ Yes ● No *(If Yes, provide the following)*
      Amount in water ________ barrels
      Ocean/Seawater ◡ No ◡ Yes
      Surface ◡ No ◡ Yes
      Groundwater ◡ No ◡ Yes
      Drinking water ◡ No ◡ Yes *(If Yes, check below.)*
      ◡ Private well ◡ Public water intake

PART G – LEAK DETECTION INFORMATION

1. Computer based leak detection capability in place? ● Yes ○ No
2. Was the release initially detected by? (check one):
   - ○ CPM/SCADA-based system with leak detection
   - ○ Static shut-in test or other pressure or leak test
   - ● Local operating personnel, procedures or equipment
   - ○ Remote operating personnel, including controllers
   - ○ Air patrol or ground surveillance
   - ○ A third party ○ Other (specify) ____________
3. Estimated leak duration days ____ hours 1

PART H – APPARENT CAUSE

Important: There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. See the instructions for guidance.

H1 – CORROSION

1. ○ External Corrosion
2. ○ Internal Corrosion

(Complete items a – e where applicable.)

a. Pipe Coating
○ Bare
○ Coated

b. Visual Examination
○ Localized Pitting
○ General Corrosion
○ Other ____________

c. Cause of Corrosion
○ Galvanic ○ Atmospheric
○ Stray Current ○ Microbiological
○ Cathodic Protection Disrupted
○ Stress Corrosion Cracking
○ Selective Seam Corrosion
○ Other ____________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
○ No ○ Yes, Year Protection Started: /____________/

e. Was pipe previously damaged in the area of corrosion?
○ No ○ Yes => Estimated time prior to accident: /______/ years /______/ months Unknown □

H2 – NATURAL FORCES

3. ○ Earth Movement => ○ Earthquake ○ Subsidence ○ Landslide ○ Other ____________
4. ○ Lightning
5. ○ Heavy Rains/Floods => ○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other ____________
6. ○ Temperature => ○ Thermal stress ○ Frost heave ○ Frozen components ○ Other ____________
7. ○ High Winds

H3 — EXCAVATION DAMAGE

8. ○ Operator Excavation Damage (including their contractors/Not Third Party)
9. ○ Third Party *(complete a-f)*

a. Excavator group
○ General Public ○ Government ○ Excavator other than Operator/subcontractor

b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable
○ Landowner-not farming related ○ Farming ○ Railroad
○ Other liquid or gas transmission pipeline operator or their contractor
○ Nautical Operations ○ Other ____________

c. Excavation was: ○ Open Trench ○ Sub-strata (boring, directional drilling, etc…)

d. Excavation was an ongoing activity (Month or longer) ○ Yes ○ No If Yes, Date of last contact /________/

e. Did operator get prior notification of excavation activity?

○ Yes; Date received: /______/ mo. /______/ day /__________/ yr. ○ No

Notification received from: ○ One Call System ○ Excavator ○ Contractor ○ Landowner

f. Was pipeline marked as result of location request for excavation? ○ No ○ Yes *(If Yes, check applicable items i - iv)*

i. Temporary markings: ○ Flags ○ Stakes ○ Paint
ii. Permanent markings: ○
iii. Marks were (check one) : ○ Accurate ○ Not Accurate
iv. Were marks made within required time? ○ Yes ○ No

H4 – OTHER OUTSIDE FORCE DAMAGE

10. ○ Fire/Explosion as primary cause of failure => Fire/Explosion cause: ○ Man made ○ Natural
11. ○ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ○ Rupture of Previously Damaged Pipe
13. ○ Vandalism

H5 – MATERIAL AND/OR WELD FAILURES

Material

14. ◯ Body of Pipe => ◯ Dent ◯ Gouge ◯ Bend ◯ Arc Burn ◯ Other ____________
15. ◯ Component => ◯ Valve ◯ Fitting ◯ Vessel ◯ Extruded Outlet ◯ Other ____________
16. ◯ Joint => ◯ Gasket ◯ O-Ring ◯ Threads ◯ Other ____________

Weld

17. ◯ Butt => ◯ Pipe ◯ Fabrication ◯ Other ____________
18. ◯ Fillet => ◯ Branch ◯ Hot Tap ◯ Fitting ◯ Repair Sleeve ◯ Other ____________
19. ◯ Pipe Seam => ◯ LF ERW ◯ HF ERW ◯ DSAW ◯ SAW ◯ Seamless ◯ Spiral ◯ Flash Weld ◯ Other ____________

Complete a-g if you indicate ***any*** *cause in part H5.*

a. Type of failure:
◯ Construction Defect => ◯ Poor Workmanship ◯ Procedure not followed ◯ Poor Construction Procedures
◯ Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? ◯ Yes ◯ No

c. Was part which leaked pressure tested before accident occurred? ◯ Yes, *complete d-g* ◯ No

d. Date of test: /__________/ yr. /______/ mo. /______/ day

e. Test medium: ◯ Water ◯ Inert Gas ◯ Other ____________________

f. Time held at test pressure: /______/ hr.

g. Estimated test pressure at point of accident: ____________________ *PSIG*

H6 – EQUIPMENT

20. ◯ Malfunction of Control/Relief Equipment => ◯ Control valve ◯ Instrumentation ◯ SCADA ◯ Communications ◯ Block valve ◯ Relief valve ◯ Power failure ◯ Other ____________
21. ◯ Threads Stripped, Broken Pipe Coupling => ◯ Nipples ◯ Valve Threads ◯ Dresser Couplings ◯ Other ____________
22. ◯ Seal Failure => ◯ Gasket ◯ O-Ring ◯ Seal/Pump Packing ◯ Other ____________

H7 – INCORRECT OPERATION

23. ● Incorrect Operation

a. Type: ◯ Inadequate Procedures ◯ Inadequate Safety Practices ● Failure to Follow Procedures
◯ Other ____________________

b. Number of employees involved who failed a post-accident test: drug test: /___0___/ alcohol test /___0___/

H8 – OTHER

24. ◯ Miscellaneous, *describe:* ____________________
25. ◯ Unknown
◯ Investigation Complete ◯ Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART I – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

THIS RELEASE OCCURRED DURING ROUTINE TESTING OF SCADA EMERGENCY SHUTDOWN SYSTEMS. THE CONTROL CENTER CONTACTED A LOCAL TECHNICIAN TO INVESTIGATE THE STATUS OF THE TWO SCRAPER TRAP ISOLATION VALVES, AS THE TESTS COULDN'T BE RUN WITHOUT THOSE VALVES. THE TECHNICIAN OBSERVED THAT THE VALVES WERE LOCKED OUT BY THE PIPELINE MAINTENANCE CREW. HE CALLED THE PERSON RESPONSIBLE FOR THE LOCKS AND OBTAINED PERMISSION TO REMOVE THEM AND RESTORE THE FULL VALVES TO REMOTE STATUS.

AFTER INVESTIGATING AN EQUIPMENT FAULT ON THE OTHER END OF THE STATION, THE TECHNICIAN RETURNED TO THE AREA AND OBSERVED OIL FLOWING OUT OF THE TRAP SUMP. THE TECHNICIAN WAS UNAWARE OF AN OPEN VENT LINE FROM THE TRAP TO THE SUMP THAT WAS LEFT OPEN BY THE MAINTENANCE CREW TO PREVENT THE SCRAPER TRAP FROM OVERPRESSURING DUE TO THERMAL EXPANSION. WHILE THE CONTROL CENTER WAS EXECUTING THE SCADA CHECKS THE SCRAPER TRAP WAS OPENED TO THE MAINLINE, ALLOWING OIL TO FLOW THROUGH THE TRAP INTO THE SUMP.

THE OIL WAS CONTAINED IN THE TERMINAL CONTAINMENT SYSTEM AND IMMEDIATELY CLEANED UP. FREE PRODUCT WAS REMOVED WITH VACUUM TRUCKS. IMPACTED SOIL WAS COLLECTED AND HAULED TO AN APPROVED LANDFILL FACILITY.

AT THIS TIME THE RESULTS OF THE INCIDENT INVESTIGATION ARE PENDING. PRELIMINARY INDICATIONS ARE THAT THE ROOT CAUSES OF THE INCIDENT ARE FAILURE TO FOLLOW LOCK-OUT PROCEDURES AND INADEQUATE PROCEDURES FOR ISOLATING AND VENTING THE SCRAPER TRAP SYSTEM.

ACTIVITY ID
128314

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

<table>
<tr><th colspan="2">Inspection Report</th><th colspan="2">Post Inspection Memorandum</th></tr>
<tr><td rowspan="3">Inspector/Submit Date:
Elizabeth Skalnek
8/31/09</td><td rowspan="3"></td><td colspan="2">Inspector/Submit Date:8/31/09 ESS</td></tr>
<tr><td colspan="2">Peer Reviewer/Date: 8/31/09 ESS</td></tr>
<tr><td colspan="2">Director Approval</td></tr>
<tr><th colspan="4">POST INSPECTION MEMORANDUM (PIM)</th></tr>
<tr><td>Name of Operator:</td><td colspan="2">Enbridge Energy Company, Inc.</td><td>OPID #: 11169</td></tr>
<tr><td>Name of Unit(s):</td><td colspan="2">Clearbrook to Deer River - IU 3083</td><td>Unit #(s):3083</td></tr>
<tr><td>Records Location:</td><td colspan="3">1129 Industrial Park Drive S.E.</td></tr>
<tr><td>Unit Type & Commodity:</td><td colspan="3">Oil released from Pump#3 at Clearbrook</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Inspection Type:</td><td>Hazardous Liquid</td><td colspan="2">Inspection Date(s): 3/13/09,8/31/09</td></tr>
<tr><td>For OPS :</td><td colspan="2"></td><td>AFO Days:</td></tr>
<tr><td>For MNOPS :</td><td colspan="2">Elizabeth Skalnek</td><td>AFO Days: 0</td></tr>
<tr><td colspan="4">MNOPS CASE #: 103554</td></tr>
</table>

Synopsis:50 Gallons of oil was released from an inboard seal on pump #3 at the Clearbrook pumping facility. The leak was detected by an oil float switch in the seal. All product was contained in the pump house and recovered.

Summary: 3/13/09 ESS Spoke to Shawn Kavajecz at 12:50 pm. 50 gallon release from inboard seal on pump #3 on line #3 at 10:30 am. There are 4 pump units in pump house; spill was contained to pump house. Leak was detected by oil float switch in seal. 30 day report will be copied to MNOPS.

7/6/09 ESS received 30 day report from Enbridge; however, the Final box was not checked.
8/18/09 ESS Requested Enbridge to fill out supplemental report.
8/19/09 ESS received final report from Enbridge.
8/31/09 ESS attached final report to OPS System and closed case.
Note: Time charged to 3/13/09 and 8/31/09 (inspection person days) but these were not AFO days.

RECEIVED SEP - 8 2009
ACTIVITY
ID 128314

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

	Inspection Report	Post Inspection Memorandum
Inspector/Submit Date: Elizabeth Skalnek 8/31/09		**Inspector/Submit Date:** 8/31/09 ESS ES **Peer Reviewer/Date:** 8/31/09 ESS ES **Director Approval**

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:** 11169	
Name of Unit(s):	Clearbrook to Deer River - IU 3083	**Unit #(s):** 3083	
Records Location:	1129 Industrial Park Drive S.E.		
Unit Type & Commodity:	Oil released from Pump#3 at Clearbrook		
Inspection Type:	Hazardous Liquid	**Inspection Date(s):** 3/13/09,8/31/09	
For OPS :		**AFO Days:**	
For MNOPS :	Elizabeth Skalnek	**AFO Days:** ~~2~~ 5	
MNOPS CASE #: 103554			

e ∅ Per Telecon w/ E. Skalnek 24 Nov 09 Revised Report on way

Synopsis: 50 Gallons of oil was released from an inboard seal on pump #3 at the Clearbrook pumping facility. The leak was detected by an oil float switch in the seal. All product was contained in the pump house and recovered.

Summary: 3/13/09 ESS Spoke to Shawn Kavajecz at 12:50 pm. 50 gallon release from inboard seal on pump #3 on line #3 at 10:30 am. There are 4 pump units in pump house; spill was contained to pump house. Leak was detected by oil float switch in seal. 30 day report will be copied to MNOPS.

7/6/09 ESS received 30 day report from Enbridge; however, the Final box was not checked.
8/18/09 ESS Requested Enbridge to fill out supplemental report.
8/19/09 ESS received final report from Enbridge.
8/31/09 ESS attached final report to OPS System and closed case.

RECEIVED JUN 1 0 2009

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		**Post Inspection Memorandum**
Inspector/Submit Date:	Victoria Livshutz VL 04-20-09	**Inspector/Submit Date:** **Victoria Livshutz 04-20-09** **Peer Reviewer/Date:** [signature] 6-1-09 **Director Approval**

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Company, Inc.		**OPID #:** 11169
Name of Unit(s):	ND - Clearbrook - IU 3083		**Unit #(s): 3083**
Records Location:	1129 Industrial Park Drive S.E. Bemidji, MN 56601		
Unit Type & Commodity:	- Interstate Hazardous Liquid		
Inspection Type:	Incident Investigation	**Inspection Date(s):**	
For OPS :			**AFO Days:** N/A
For MNOPS :	Victoria Livshutz		**AFO Days: N/A**
MNOPS CASE #: 101912			

Summary: The Duty Officer called and notified us that they received notification from Ramona Mendoza with USUPA who was calling to make sure we know of a spill and a small fire which happened at the Enbridge Viking Pumping station. Ramona spoke with Al Aleknavicius of Enbridge and was advised that they were adding additives to go to 1/2" and then to a 2" line connected to the main 18" crude oil line. According to Al, the 1/2" line failed causing a fire. The fire was extinguished with a 30 LB fire extinguisher. According to Jay Johnson of Enbridge, the preliminary investigation revealed that, apparently, the accident occurred as two Enbridge employees were thawing out a small drag reducer (DRA) injection line at Enbridge's Viking Station in Minnesota. The employees were using a heater to thaw out the DRA, and loosening union connections on the DRA line to check if line was thawed. At the last connection of the DRA line to the pipeline, when they loosened the connection a small amount of crude was released with a small fire. The fire was contained to the access well where DRA line connects to the pipeline. The DRA line connection (2-inch valve) was immediately isolated from the pipeline by the employees, and the fire extinguished using hand-held extinguisher. The involved employees were sent for drug and alcohol testing. There were no injuries, and no off-site impacts. Enbridge is investigating the situation. NRC notification #868932 was made by Enbridge concerning this event. The Operator's written incident report # 2009DO71-8318 was submitted to PHMSA on March 18, 2008. A copy of this report was e-mailed to MNOPS.

Memorandum

U.S. Department
of Transportation
Pipeline and
Hazardous Materials
Safety Administration

Central Region Office

Office of Pipeline Safety

Date: May 5, 2009

Subject: Accident Report: Enbridge Energy Limited Partnership, Inc.,
near New Carlisle, IN
Crude oil leak
May 27, 2008

D A

From: for Carl Griffis, Staff Engineer

To: Ivan A. Huntoon, Director Central Region, PHP-300 IAH

SUMMARY

At approximately 2:00 p.m. CDT on May 27, 2008, Enbridge personnel incurred a release of crude oil at MP 519 of Line 6B near New Carlisle, IN. Six barrels of crude oil were estimated to have been released to the ground. Upon excavation of the valve area, the operator discovered that the crude oil had escaped from a flange connection to an idled C1 line and that an incorrect sized gasket had been installed.

ACCIDENT

At approximately 2:00 p.m. CDT on May 27, 2008, Enbridge personnel reported crude oil at MP 519 of Line 6B near New Carlisle, IN (Exhibits 1 and 2). Enbridge had re-pressurized the idled loop line C1 with nitrogen beginning on May 20, 2008, and in the process of performing maintenance on the valve station near New Carlisle, IN discovered crude oil on the ground. Approximately six barrels of crude oil were estimated to have been released. Upon excavation of the valve area it was discovered that the crude oil had escaped from a flange connection on the idled C1 line, which had an incorrect gasket installed. See Exhibit 3 for valve schematic.

The leak occurred on an idled loop segment starting at MP 489 and terminating at MP 519. This loop section (C1) along with 7 other loop sections was installed and operational in 1997. Double face blind flanges were installed at all crossover pipe locations to isolate the mainline 6B from the loop sections when the loop sections were deactivated in 1990-1991. Upon excavation of the double face blind flange at the New Carlisle valve location, it was determined that an incorrect gasket had been installed on the loop side of the double face blind flange. A 30" gasket was incorrectly installed in a 34" flange set and additionally the leaking gasket appeared to be damaged. This location is a low spot for the loop line, which allowed residual oil to collect at this point in the line. The loop line C1 was re-pressurized with nitrogen to 22 psig in May 2008 after it was noticed that there was zero pressure in the line in late 2007. The other seven loop lines were also to be re-pressurized.

Enbridge visually inspected all other crossover locations and verified that pressure was not decreasing after the re-pressurization. Since some crude oil was found at the New Carlisle location in the idled loop line, Enbridge plans to perform an internal corrosion scan to determine the extent (if any) of corrosion. Enbridge has expansion plans for line 6B which will involve the reconfiguration of the mainline pipe and the loop line crossover segments. Exact plans have not been determined at this time. See Exhibit 4 for more details on Enbridge discussion.

INVESTIGATION

This accident was investigated as a follow-up action to Enbridge's' accident notification filed with the National Response Center (NRC) on May 27, 2008, at 18:42 CDT. The investigation included the gathering of information by telephone and e-mail. The investigator, Carl Griffis, conducted an on-site investigation at the accident site on May 28, 2008, in New Carlisle, IN.

FINDINGS

1) Approximately six barrels of crude oil was released from the idled C1 loop segment of the Enbridge mainline 6B system near New Carlisle, IN during the nitrogen pressurization of the loop line.

2) The source of the leak was determined to be an incorrect sized gasket which was also damaged.

3) Because the location of the gasket leak was at a low spot in the idled line, residual crude oil preferentially gathered at this location and leaked out at the gasket location.

4) No other indications of similar type leaks were detected by the Enbridge personnel inspection of other mainline and loop line crossover connections

Exhibit 1 – NRC Report #872228
Exhibit 2 - 7000-1 Accident Report Form #20080200-7361
Exhibit 3 - Enbridge Valve Setting Schematic, New Carlisle, IN
Exhibit 4 - Enbridge email from Vince Kolbuck to PHMSA 5/30/2008
Exhibit 5 - Photos

EXHIBIT #1

ENBRIDGE
NRC REPORT
#872228

Griffis, Carl <PHMSA>

From: CMC-01 <OST>
Sent: Tuesday, May 27, 2008 5:54 PM
To: PHP Accident/Incident Cadre <PHMSA>; PHMSA PHP300 CENTRAL
Cc: CMC-01 <OST>; CMC-02 <OST>; Jennifer.Mansour@faa.gov; Holland, Rena <OST>; stuckey, william <OST>; Winslow Powell
Subject: NRC#872228 Transmission Line Material Release in New Carlisle, IN - No Injuries or Fatalities, DOT Regulated, Enbridge Energy

NRC#872228

What: Caller is reporting a discharge of crude oil from a pipeline system due to unknown causes. The pipeline will have to be excavated. The release went to the ground.

When: The incident occurred on 27-MAY-08 at 14:00 local time.

Where: County: ST. Joseph City: New Carlisle State: IN

NATIONAL RESPONSE CENTER 1-800-424-8802
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 872228

INCIDENT DESCRIPTION

*Report taken by: CIV ABAYOMI SNOWDEN at 18:42 on 27-MAY-08
Incident Type: PIPELINE
Incident Cause: EQUIPMENT FAILURE
Affected Area:
The incident occurred on 27-MAY-08 at 14:00 local time.
Affected Medium: LAND

REPORTING PARTY

Name: VINCE KOLBUCK
Organization: ENBRIDGE ENERGY
Address: 1500 WEST MAIN STREET
GRIFFITH, IN 46319
ENBRIDGE ENERGY reported for the responsible party.
PRIMARY Phone: (219)9227004
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: VINCE KOLBUCK
Organization: ENBRIDGE ENERGY
Address: 1500 WEST MAIN STREET
GRIFFITH, IN 46319
PRIMARY Phone: (219)9227004

INCIDENT LOCATION

51734 TIMOTHY ROAD County: ST. JOSEPH
City: NEW CARLISLE State: IN

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 250 GALLON(S)

DESCRIPTION OF INCIDENT

CALLER IS REPORTING A DISCHARGE OF CRUDE OIL FROM A PIPELINE SYSTEM DUE TO UNKNOWN CAUSES. THE PIPELINE WILL HAVE TO BE EXCAVATED. THE RELEASE WENT TO THE GROUND.

SENSITIVE INFORMATION

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Hospitalized: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure	
Air: N				
Road: N				Major Artery:N
Waterway: N				
Track: N				

Environmental Impact: UNKNOWN
Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

ISOLATED THE PIPELINE, CONTAINING THE AREA AND PREPARING FOR EXCAVATION.

Release Secured: NO

Release Rate:

Estimated Release Duration:

WEATHER

Weather: OVERCAST, 50ºF Wind speed: 20 MPH Wind direction:

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE

State/Local: NONE

State/Local On Scene: NONE

State Agency Number: NONE

NOTIFICATIONS BY NRC

ATLANTIC STRIKE TEAM (MAIN OFFICE)
27-MAY-08 18:48 (609)7240008

USCG ICC (ICC ONI)
27-MAY-08 18:48 (301)6693363

CG INVESTIGATIVE SVC CHICAGO (CGIS ROA CHICAGO)
27-MAY-08 18:48 (630)9862160

DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
27-MAY-08 18:48 (202)3661863

U.S. EPA V (MAIN OFFICE)
(312)3532318

NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
27-MAY-08 18:48 (202)2829201

NOAA RPTS FOR IN (MAIN OFFICE)
27-MAY-08 18:48 (206)5264911

PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
27-MAY-08 18:48 (202)3660568

IN DEPT ENV MNGMT (MAIN OFFICE)
27-MAY-08 18:48 (317)2337745

MICHIGAN DEQ (MAIN OFFICE)
27-MAY-08 18:48 (517)2411252

SURFACE TRANS SECURITY INSPECT PROG (COMMAND CENTER)
27-MAY-08 18:48 (773)8587516

ADDITIONAL INFORMATION

CALLER HAS NO ADDITIONAL INFORMATION.

*** END INCIDENT REPORT #872228 ***

Report any problems or Fax number changes by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT http://www.nrc.uscg.mil

EXHIBIT #2

ENBRIDGE
7000-1 ACCIDENT REPORT FORM
#20080200-7361

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation

Form Approved
OMB No. 2137-0047

U.S. Department of Transportaion
Research and Special Programs Administration

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date JUN 26 2008

No. 20080200 - 7361
(DOT Use Only)

INSTRUCTIONS

Important: ***Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov***

PART A - GENERAL REPORT INFORMATION check: ☐ Original Report ☒ Supplemental Report ☒ Final Report

1. a. Operator's OPS 5-digit Identification Number (if know) / 11169 /
2. b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if know) / /
   c. Name of Operator ENBRIDGE ENERGY, LIMITED PARTNERSHIP
   d. Operator street address 119 N 25TH STREET E
   e. Operator address SUPERIOR DOUGLAS WI 54880
   City, County, State and ZIP Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident
   / 1209 / / 05 / / 27 / /2008 /
   hr. month day year

3. Location of accident
   (If offshore, do not complete a through d See Part C.1)

   a. Latitude: 41 44 26 Longitude: -86 30 21
   (If not available, see instructions for how to provide specific location)

   b. NEW CARLISLE ST JOSEPH
   City and County or Parish

   c. IN 46552
   State and Zip Code

   d. Mile post/valve station ● or Survey Station no. ○
   (whichever gives more accurate location)
   519

4. Telephone report
   / 872228 / / 05 / / 27 / / 2008 /
   NRC Report Number *month* *day* *year*

5. Losses (Estimated)

Public/Community Losses reimbursed by operator:

Public/private property damage	$ 0
Cost of emergency response phase	$ 0
Cost of environmental remediation	$ 0
Other Costs	$ 0
(describe)	

Operator Losses:

Value of product lost	$ 0
Value of operator property damage	$ 0
Other Costs	$ 100,000
(describe) CLEANUP	
Total Costs:	$ 100,000

6. Commodity Spilled ● Yes ○ No
   (If Yes, complete Parts a through c where applicable)
   a. Name of commodity spilled CRUDE OIL
   b. Classification of commodity spilled:
   - ○ HVLs/other flammable or toxic fluid which is a gas at ambient conditions
   - ○ CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditons
   - ○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
   - ● Crude oil

c. Estimated amount of commodity involved :
- ● Barrels
- ○ Gallons (check only if spill is less than one barrel)

Amounts :
Spilled : 6
Recovered:

CAUSES FOR SMALL SPILLS ONLY *(5 gallons to under 5 barrels)* (For large spills [5 barrels or greater] see Part H)

○ Corrosion ○ Natural Forces ○ Excavation Damage ○ Other Ouside Force Damage ○ Other
○ Materal and/or Weld Failures ○ Equipment ○ Incorrect Operation

PART B - PREPARER AND AUTHORIZED SIGNATURE

THERESA PICTON
(type or print) Preparer's Name and Title

(715) 394-1468
Area Code and Telephone Number

THERESA.PICTON@ENBRIDGE.COM
Preparer's E-mail Address

(832) 325-5477
Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Cod and Telephone Number

Form RSPA F 7000-1 (01-2001)

PART C - ORIGIN OF THE ACCIDENT *(Check all that apply)*

1. Additional location information
   a. Line segment name or ID 6
   b. Accident on Federal land other than Outer Continental Shelf ○ Yes ● No
   c. Is pipeline interstate? ● Yes ○ No

Offshore: ○ Yes ● No *(comple d if offshore)*
d. Area Block #
State / / or Outer Continental Shelf ☐

2. Location of system involved (check all that apply)
- [x] Operator's Property
- [ ] Pipeline Right of Way
- [ ] High Consequence Area (HCA)?
  Describe HCA

3. Part of system involved in accident
- ○ Above Ground Storage Tank
- ○ Cavern or other below ground storage facility
- ○ Pump/meter station; terminal/tank farm piping and equipment, including sumps
- ● Other Specify: **INACTIVE LOOP LINE SCRAPER FACILITY**
- ○ Onshore **pipeline**, including valve sites
- ○ Offshore **pipeline**, including platforms

If failure occurred on ***pipeline****, complete items a - g:*

a. Type of leak or rupture
- ○ Leak: ○ Pinhole ○ Connection Failure *(complete sec. H5)* ○ Puncture, diameter *(inches)*
- ○ Rupture: ○ Circumferential - Separation ○ Longitudinal - Tear/Crack, length *(inches)* Propagation Length, total, both sides *(feet)*
- ○ N/A
- ○ Other

b. Type of block valve used for isolation of immediate section:
Upstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve
Downstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve

c. Length of segment isolated ft
d. Distance between valves ft
e. Is segment configured for internal inspection tools? ○ Yes ○ No
f. Had there been an in-line inspection device run at the point of failure? ○ Yes ○ No ○ Don't Know ○ Not Possible due to physical constraints in the system
g. If Yes, type of device run *(check all that apply)*
- ☐ High Resolution Magnetic Flux tool Year run:
- ☐ Low Resolution Magnetic Flux tool Year run:
- ☐ UT tool Year run:
- ☐ Geometry tool Year run:
- ☐ Caliper tool Year run:
- ☐ Crack tool Year run:
- ☐ Hard Spot tool Year run:
- ☐ Other tool Year run:

4. Failure occurred on
○ Body of Pipe ○ Pump ○ Component ○ Repair Sleeve ○ Girth Weld
○ Pipe Seam ○ Sump ○ Valve ○ Welded Fitting
○ Scraper Trap ○ Joint ○ Metering Facility ○ Bolted Fitting
● Other *(specify)* **BOLTED FITTING - GASKET**

Year the component that failed was installed: / 1994 /

5. Maximum operating pressure (MOP)
   a. Estimated pressure at point and time of accident: 20 *PSIG*
   b. MOP at time of accident: 624 *PSIG*
   c. Did an overpressurization occur relating to the accident? ○ Yes ● No

PART D - MATERIAL SPECIFICATION

1. Nominal pipe size *(NPS)* / 34 / in.
2. Wall thickness / .25 / in.
3. Specification API-5L-X52 SMYS / /
4. Seam type
5. valve type
6. *Manufactured by* *in year* / 1994 /

PART E - ENVIRONMENT

1. *Area of accident*
○ Under pavement ● Underground ○ Inside/under building ○ In open ditch ○ Above ground ○ Under water ○ Other

2. *Depth of cover:* 60 *inches*

PART F - CONSEQUENCES

1. **Consequences** ***(check and complete all that apply)***

a.

	Fatalities	Injuries
Number of operator employees:		0
Contractor employees working for operator:		0
General public:		0
Totals:		0

b. Was pipeline/segment shutdown due to leak? ○ Yes ● No
If Yes, how long? days hours minutes

c. Product ignited ○ Yes ● No d. Explosion ○ Yes ● No
e. ☐ **Evacuation** *(general public only)* / / people
Reason for Evacuation:
○ Precautionary by company
○ Evacuation required or initiated by public official
f. Elapsed time until area was made safe: / / hr. / 30 / min.

2. **Environmental Impact**
   a. Wildlife Impact: Fish/aquatic ○ Yes ● No; Bird ○ Yes ● No; Terrestrial ○ Yes ● No
   b. Soil Contamination ● Yes ○ No
      If Yes, estimated number of cubic yards: 440
   c. Long term impact assessment performed: ○ Yes ● No
   d. Anticipated remediation ○ Yes ● No
   If Yes, Check all that apply: ☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife

e. Water Contamination: ○ Yes ● No *(If Yes, provide the following)*
Amount in water barrels
Ocean/Seawater ○ No ○ Yes
Surface ○ No ○ Yes
Groundwater ○ No ○ Yes
Drinking water ○ No ○ Yes *(If Yes, check below.)*
○ Private well ○ Public water intake

PART G - LEAK DETECTION INFORMATION

1. Computer based leak detection capability in place? ○ Yes ● No
2. Was the release intially detected by? (check one):
   - ○ CPM/SCADA-based system with leak detection
   - ○ Static shut-in test or other pressure or leak test
   - ● Local operating personnel, procedures or equipment
   - ○ Remote operating personnel, including controllers
   - ○ Air patrol or ground surveillance
   - ○ A third party ○ Other (specify) ____________
3. Estimated leak duration days __7__ hours

PART H - APPARENT CAUSE

Important: There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. Secc the instructions for guidance.

H1 - CORROSION

1. ○ External Corrosion
2. ○ Internal Corrosion

(Complete items a - e where applicable.)

a. Pipe Coating
○ Bare
○ Coated

b. Visual Examination
○ Localized Pitting
○ General Corrosion
○ Other ____________

c. Cause of Corrosion
○ Galvanic ○ Atmospheric
○ Stray Current ○ Microbiological
○ Cathodic Protection Disrupted
○ Stress Corrosion Cracking
○ Selective Seam Corrosion
○ Other ____________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
○ No ○ Yes, Year Protection Started: / /

e. Was pipe previously damaged in the area of corrosion?
○ No ○ Yes => Estimated time prior to accident: / / years / / months Unknown ☐

H2 - NATURAL FORCES

3. ○ Earth Movement => ○ Earthquake ○ Subsidence ○ Landslide ○ Other ____________
4. ○ Lightning
5. ○ Heavy Rains/Floods => ○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other ____________
6. ○ Temperature => ○ Thermal stress ○ Frost heave ○ Frozen components ○ Other ____________
7. ○ High Winds

H3 - EXCAVATION DAMAGE

8. ○ Operator Excavation Damage (including their contractors/Not Third Party)
9. ○ Third Party *(complete a-f)*

a. Excavator group
○ General Public ○ Government ○ Excavator other than Operator/subcontractor

b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable
○ Landowner-not farming related ○ Farming ○ Railroad
○ Other liquid or gas transmission pipeline-operator or their contractor
○ Nautical Operations ○ Other

c. Excavation was: ○ Open Trench ○ Sub-strata (boring, directional drilling, etc...)

d. Excavation was an ongoing activity (Month or longer) ○ Yes ○ No If Yes, Date of last contact / /

e. Did operator get prior notification of excavation activity?
○ Yes; Date received: / / mo. / / day / / yr. ○ No
Notification received from: ○ One Call System ○ Excavator ○ Contractor ○ Landowner

f. Was pipeline marked as result of location request for excavation? ○ No ○ Yes (If Yes, check applicable items i - iv)
i. Temporary markings: ○ Flags ○ Stakes ○ Paint
ii. Permanent markings: ○ Yes ○ No
iii. Marks were (check one) : ○ Accurate ○ Not Accurate
iv. Were marks made within required time? ○ Yes ○ No

H4 - OTHER OUTSIDE FORCE DAMAGE

10. ○ Fire/Explosion as primary cause of failure => Fire/Explosion cause: ○ Man Made ○ Natural
11. ○ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ○ Rupture of Previously Damaged Pipe
13. ○ Vandalism

H5 - MATERIAL AND/OR WELD FAILURES

Material

14. ○ Body of Pipe => ○ Dent ○ Gouge ○ Bend ○ Arc Burn ○ Other

15. ○ Component => ○ Valve ○ Fitting ○ Vessel ○ Extruded Outlet ○ Other

16. ● Joint => ● Gasket ○ O-Ring ○ Threads ○ Other

Weld

17. ○ Butt => ○ Pipe ○ Fabrication ○ Other

18. ○ Fillet => ○ Branch ○ Hot Tap ○ Fitting ○ Repair Sleeve ○ Other

19. ○ Pipe Seam => ○ LF ERW ○ DSAW ○ Seamless ○ Flash Weld ○ HF ERW ○ SAW ○ Spiral ○ Other

Complete a-g if you indicate **any** *cause in part H5.*

a. Type of failure:

● Construction Defect => ○ Poor Workmanship ● Procedure not follow ed ○ Poor Construction Procedures

○ Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? ○ Yes ● No

c. Was part w hich leaked pressure tested before accident occurred? ● Yes, complete d-g ○ No

d. Date of test: / 1979 / yr. / 8 / mo. / 8 / day

e. Test medium: ● Water ○ Inert Gas ○ Other

f. Time held at test pressure: / 24 / hr.

g. Estimated test pressure at point of accident: 824 *PSIG*

H6 - EQUIPMENT

20. ○ Malfunction of Control/Relief Equipment => ○ Control valve ○ Instrumentation ○ SCADA ○ Communications ○ Block valve ○ Relief valve ○ Pow er failure ○ Other

21. ○ Threads Stripped Broken Pipe Coupling => ○ Nipples ○ Valve Threads ○ Dresser Couplings ○ Other

22. ○ Seal Failure => ○ Gasket ○ O-Ring ○ Seal/Pump Packing ○ Other

H7 - INCORRECT OPERATION

23. ○ Incorrect Operation

a. Type ○ Inadequate Procedures ○ Inadequate Safety Practices ○ Failure to Follow Procedures ○ Other

b. Number of employees involved w ho failed a post-accident test: drug test: / / alcohol test / /

H8 - OTHER

24. ○ Miscellaneous, *describe:*

25. ○ Unknow n

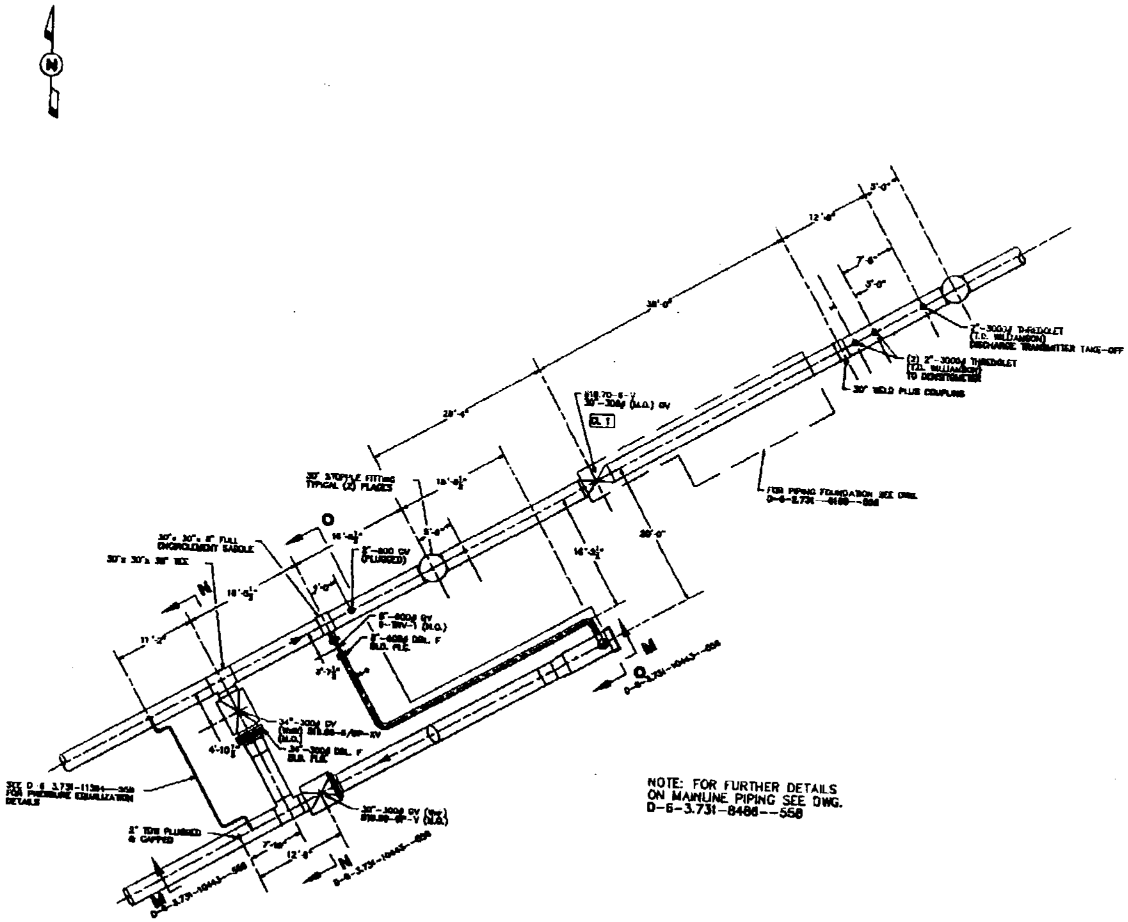
○ Investigation Complete ○ Still Under Investigation (*Submit a supplemental report when investigation is complete*)

PART I - NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT (Attach additional sheets as necessary)

THE DEACTIVATED LOOP LINE SECTION C1 HAD BEEN REPRESSURIZED WITH NITROGEN ON MAY 20, 2008. ON MAY 27TH, MAINTENANCE ACTIVITY WAS SCHEDULED ON LINE 6B AND DURING THE LOCK OUT PROCESS OIL WAS DISCOVERED. UPON EXCAVATING THE RELEASE AREA, IT WAS DETERMINED THAT A FLANGE CONNECTION WAS THE SOURCE. FURTHER INVESTIGATION REVEALED THAT AN INCORRECT GASKET HAD BEEN INSTALLED. THE CORRECT GASKET WAS INSTALLED ON 5/29/08. AT THIS TIME ALL CONTAMINATED SOIL HAS BEEN REMOVED AND SOIL SAMPLES HAVE CLEARED US TO BACKFILL THE EXCAVATION.

EXHIBIT #3

ENBRIDGE
VALVE SETTING SCHEMATIC
NEW CARLISLE, IN



NOTE: FOR FURTHER DETAILS
ON MAINLINE PIPING SEE DWG.
D-6-3.731-8486--558

[Ql 1] REMOTE OPERATED
VALVE WITH
VAX DESIGNATION

E-5.92-10281--555	ROUTE SHEET C-3[illegible]
D-6-3.731-10443--558	MAINLINE TAKE-OFF SECTIONS
Z.82-0178	CONCRETE PIPE SUPPORT
D-6-2.731-[illegible]	TIE-IN CONCRETE SUPPORT
D-6-3.731-[illegible]	MAINLINE TAKE-OFF
D-6-3.731-[illegible]	FORMER CARLISLE TAKE-OFF ISOMETRIC
REFERENCE DRAWINGS	

NO	REVISION	BY DATE	APP
10	REVISED TITLE BLOCK	MHS 6-10-[illegible]	KWB
9	ADDED VAX NUMBER	CAL 1/[illegible]/[illegible]	
8	REV'D & REDRAWN ON CADD VALVE NUMBERING & AFE-94-6-217	CAL 11/13/[illegible]	JAJ

ENBRIDGE

GRIFFITH TO SARNIA
MAINLINE 6B
M.P. 519.70
FORMER CARLISLE TAKE-OFF
PIPING

PROJECT: AFE # REVISED AND REDRAWN ON CADD

EXHIBIT #4

ENBRIDGE
EMAIL TO PHMSA 5/30/2008

Ochs, Gregory <PHMSA>

From: Vince.Kolbuck@enbridge.com
Sent: Friday, May 30, 2008 12:30 PM
To: Griffis, Carl <PHMSA>
Cc: Bill_Burdeau/US/Enbridge@Enbridge.com; Jay_A_Johnson/LPL@Enbridge.com; Shaun_Kavajecz/US/Enbridge@Enbridge.com; Joe_Richardson/US/Enbridge@Enbridge.com; Shaun.Dawe@enbridge.com; Scott.Ironside@enbridge.com; Tom.Fridel@enbridge.com
Subject: Line 6B Timothy Road Leak Information - Update # 2
Attachments: M.P.-0520-558-06-3.731-08572-10-TOF Layout1 (1).pdf; pic00041.jpg; pic18467.jpg; pic06334.jpg; pic26500.jpg; pic19169.jpg

M.P.-0520-558-06-3.731-08572-1... pic00041.jpg pic18467.jpg pic06334.jpg pic26500.jpg pic19169.jpg

Good morning Carl,

I wanted to provide you with some additional information regarding the Line 6B - MP 519 pipeline leak that we discovered May 27 at 2:00 PM C.S.T.

Attached for your reference is a detailed drawing of MP 519 location (see attached pdf file).

(See attached file: M.P.-0520-558-06-3.731-08572-10-TOF Layout1 (1).pdf)

Line 6B Loop History:

The leak occurred on a deactivated (idle) pipeline loop segment starting at Enbridge MP 489 and terminating at MP 519 (a total distance of approximately 30 miles).
This loop section (called C1) along with 7 others along were installed and operational in 1977.
The 8 loop sections were deactivated in 1990 - 1991. The deactivation process involved running purge pigs pushed with nitrogen to evacuate the crude oil from each of the loop segments. Double face blind flanges were installed at all cross over pipe locations to fully isolate the loop segments from the active line 6B. Cathodic protection has been maintained on all loop segments since deactivation (Note: The loop segments are not cathodically isolated and a protected as part of the overall cathodic protection system installed on line 6B.
The pressure on the loop segments is checked periodically to ensure positive pressure is maintained. Loop C1 was found to have zero positive pressure in late 2007 so we initiated a project to re-pressurize all loop segments as several others had low pressure readings. We completed nitrogen pressurization of loop C1 on May 22, 2008 to a pressure of 21 psi.

Failure Analysis and Post Failure Work:

The leak that occurred at MP 519 resulted from a gasket failure. After

the suspect gasket was removed it was found to be the wrong size. The gasket dimensions indicated it was a 30" X 300# series incorrectly installed in a 34" x 300# flange set.
Additionally the lower left quadrant of the gasket appeared to have excessive damage.
Loop C1 has a high point elevation at MP 503 of 920 feet and MP 519 has an elevation of 820 feet, so the MP 519 is a low point in the loop segment allow residual crude to collect at this location.
When the pipe system was opened for gasket replacement there was no additional product left in the loop segment (all free oil left in the loop apparently escaped during the leak event).

Enbridge Inspection & Repair Activities:

The damaged gasket was removed and new gasket(s) were reinstalled on both sides of the 34" double face blind flange at MP 519. The flange set was re-torqued to Enbridge specifications.
Tightness of second 8" x 300# blind flange was verified at MP 519.
Since Enbridge had excavated another portion of this loop segment for planned work at Laporte station (MP 499), we checked gasket size and bolt torque to see if this gasket problem was systematic. We found all bolts to be adequately torqued and gaskets appeared to be correct size upon visual examination. (Note: The loop tie segments checked at LaPorte station were scheduled for removal as part of an overall removal program on line 6B).
Since this leak was unexpected and we had re-pressurized all 8 loop segments, Enbridge crews visually inspected all cross over locations (18 total) and verified that loop pressure was not decreasing in any segment. No indications of leaks were found.
Since a small amount of crude was found at a low point in this loop section we are planning to perform an internal corrosion scan to verify whether or not internal corrosion has occurred over time. The scanning technology will provide a 1/4" X 1/4" grid pattern and will give a thorough indication of the internal corrosion status at this location.
Per your request, once all of our site work is completed at MP 519 we intend to take pipe off & on cathodic potential readings for verification purposes.

(Embedded image moved to file: pic00041.jpg)

Long Term Strategy:

As mentioned previously, there are expansion plans for line 6B which are likely to include reconfiguration of mainline pipe at many of these loop tie-in locations. We will verify what the overall strategy and timing is going to be for this work as it will eliminate many of these cross over piping sections.
We are also looking at what type of inspection / removal program we can put in place. This will take some time to develop and we will have to keep in contact with PHMSA regarding how we can proceed with this initiative.

Thanks and please contact me if you require any additional information.

Vince Kolbuck
Supervisor, Regional Engineering
Enbridge (U.S.) Inc.
1500 West Main St, Griffith, IN, 46319
Office Phone: (219) 922-7004
Office Fax: (219) 922-3128
e-mail: vince.kolbuck@enbridge.com
----- Forwarded by Vince P Kolbuck/LPL on 05/30/2008 10:19 AM -----

---

Vince P Kolbuck
05/28/2008 08:50 AM

To: CARL.GRIFFIS@dot.gov
cc: Bill Burdeau/US/Enbridge@LPL, Jay A Johnson/LPL@LPL, Shaun Kavajecz/US/Enbridge@LPL, Joe Richardson/US/Enbridge@LPL
Subject: Line 6B Timothy Road Leak Information
File Database: File:
Would you like the recipient to view the FILING info? |---------|
|( ) Yes |
(*) No

Good morning Carl,

Here are some pictures of the Timothy Road line 6B leak location.

As we had discussed, the leak appears to be coming from a de-activated loop line which is parallel to the active crude oil line. There is associated cross over piping at this location. Last week we repressurized this particular loop section as part of routine maintenance of the loop segments. When the leak was discovered yesterday there was a small amount of gas hissing out of the ground and testing showed zero oxygen levels indicating the presence of nitrogen. Based on this we currently think the leak is located on the deactivated line.

We expect to have the site substantially exposed at some point today and we will be able to determine the source of the leak.

The pipeline is currently shut down and will be remain shut down until the source of the leak is known.

Thanks

(Embedded image moved to file: pic18467.jpg)

(Embedded image moved to file: pic06334.jpg)

(Embedded image moved to file: pic26500.jpg) (Embedded image moved to file: pic19169.jpg)

Vince Kolbuck
Supervisor, Regional Engineering
Enbridge (U.S.) Inc.
1500 West Main St, Griffith, IN, 46319
Office Phone: (219) 922-7004
Office Fax: (219) 922-3128
e-mail: vince.kolbuck@enbridge.com

EXHIBIT #5

ENBRIDGE PHOTOS

Photos

Photo#1: Looking N at crossover block valve between main line 6B and loop line C1.
Photo#2: Looking E at crossover block valve between mainline 6B and loop line C1. The mainline block valve is in the background just to the left of the crossover block valve stem indicator.

Photo #1

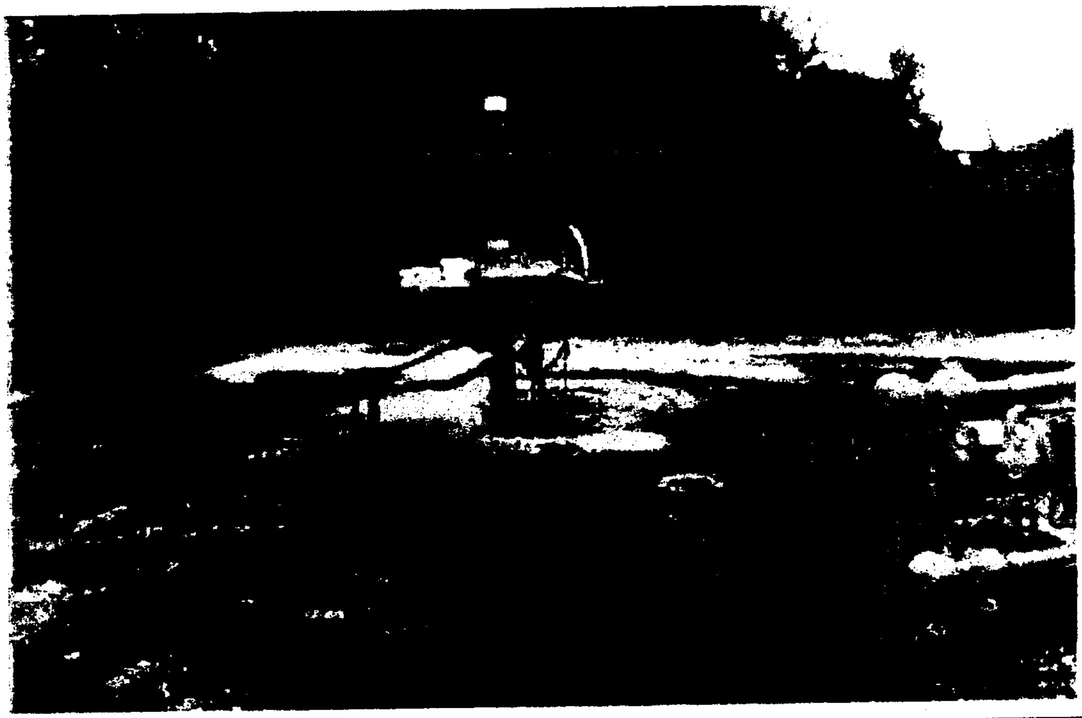


Photo #2

Photos

Photo#3: Looking SE at crossover block valve on the left and block valve on the loop line C1 on the right.
Photo#4: Looking W at leaking flange gasket on crossover block valve on loop line C1 side

Photo #1

Photo #4

/ HAAS

RECEIVED JUN 1 0 2009
Acc Date - 02/27/2009
BEP

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		Post Inspection Memorandum
Inspector/Submit Date:	Victoria Livshutz VL 04-20-09	**Inspector/Submit Date: Victoria Livshutz 04-20-09**
		Peer Reviewer/Date: Elliott Blackwell 6-1-09
		Director Approval

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Company, Inc.		**OPID #:** 11169
Name of Unit(s):	ND - Clearbrook - IU 3083		**Unit #(s): 3083**
Records Location:	1129 Industrial Park Drive S.E. Bemidji, MN 56601		
Unit Type & Commodity:	Interstate Hazardous Liquid		
Inspection Type:	Incident Investigation	**Inspection Date(s):**	
For OPS :			**AFO Days:** N/A
For MNOPS :	Victoria Livshutz		**AFO Days: N/A**
MNOPS CASE #: 101912			

Summary: The Duty Officer called and notified us that they received notification from Ramona Mendoza with USUPA who was calling to make sure we know of a spill and a small fire which happened at the Enbridge Viking Pumping station. Ramona spoke with Al Aleknavicius of Enbridge and was advised that they were adding additives to go to 1/2" and then to a 2" line connected to the main 18" crude oil line. According to Al, the 1/2" line failed causing a fire. The fire was extinguished with a 30 LB fire extinguisher. According to Jay Johnson of Enbridge, the preliminary investigation revealed that, apparently, the accident occurred as two Enbridge employees were thawing out a small drag reducer (DRA) injection line at Enbridge's Viking Station in Minnesota. The employees were using a heater to thaw out the DRA, and loosening union connections on the DRA line to check if line was thawed. At the last connection of the DRA line to the pipeline, when they loosened the connection a small amount of crude was released with a small fire. The fire was contained to the access well where DRA line connects to the pipeline. The DRA line connection (2-inch valve) was immediately isolated from the pipeline by the employees, and the fire extinguished using hand-held extinguisher. The involved employees were sent for drug and alcohol testing. There were no injuries, and no off-site impacts. Enbridge is investigating the situation. NRC notification #868932 was made by Enbridge concerning this event. The Operator's written incident report # 2009DO71-8318 was submitted to PHMSA on March 18, 2008. A copy of this report was e-mailed to MNOPS.

RECEIVED FEB 17 2009

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Brian E. Pierzina

Inspection Report		Post Inspection Memorandum	
Inspector/Submit Date:	Brian Pierzina 02/03/2009	**Inspector/Submit Date:** Brian Pierzina 02/03/2009	
		Peer Reviewer/Date: 2/11/09	
		Director Approval	
POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Company, Inc.		**OPID #:** 11169
Name of Unit(s):	Clearbrook to Deer River - IU 3083		**Unit #(s):** 3083
Records Location:	219 N. 25th Street East, Superior, WI 54880		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil		
Inspection Type:	Pipeline Failure – Material Defect		**Inspection Date(s):** 1/29-31, 3/28,31, 4/9, 8/14/2008 ← NON-AFO
For OPS:			**AFO Days:**
For MNOPS:	Brian Pierzina		**AFO Days:** BEP (4)
MNOPS CASE #: 7715			NON AFO (1)

Synopsis: (Previously reported on PIM sent 01/09/2009) On November 13, 2007, Enbridge Energy discovered a crude oil leak near MP 912, approximately 3 miles southeast of the Clearbrook Terminal. The leak was discovered at approximately 7:00 AM by Enbridge electrician, Sam Sparhawk, as he was traveling to work. The leak was determined to be on the 34 inch Line 3, in the longitudinal weld seam of the pipe. The leak quantity was estimated by Enbridge as 2 bbls. The leak was initially repaired with a four foot long tight fitting repair sleeve, but an 11 foot section of pipe containing the defect was ultimately removed on November 28, 2007, to allow for further metallurgical evaluation. Prior to completing the replacement, a failure occurred, with subsequent ignition, resulting in the death of two Enbridge employees (MNOPS - Case #7751).

(Update 02/03/2009) This PIM has been prepared to account for MNOPS activities, particularly AFO Days, which occurred during 2008. The issues and potential mitigative actions associated with this Case, and the long seam defects associated with Enbridge's 34 inch Line 3 U.S. Steel pipe are still under consideration by Enbridge and PHMSA Central Region. It is expected this Case will remain open until formal plans for corrective action are adopted. For the time being, Enbridge has placed a pressure restriction on the U.S. Steel Pipe between Clearbrook and Superior.

Summary: (Previously Reported) At 8:22 AM, on November 13, 2007, Blake Olson, Supervisor of Enbridge's Clearbrook Terminal, notified the Duty Officer of a leak in a pasture, on County Road 3, about 3.5 miles east of Hwy 92. The leak was determined to be on Enbridge's 34 inch Line3, in the longitudinal weld seam of the pipe, and was repaired using a four foot long tight fitting repair sleeve.

The pipe at this location was manufactured by U.S. Steel, and is .344 inch wall – X-52. Ultrasonic inspection indicated an internally connected defect in the toe of the DSAW weld seam, with characteristics of a fatigue crack. Initial reports from Enbridge's Integrity Department were that there were no features reported at this location from either of the two previous CD tool runs, both of which were subsequent to the July 4, 2002 rupture near Cohasset.

The leak site was in the ditch on the south side of County Road 3, within Clearwater County ROW. It was initially detected by Enbridge electrician, Sam Sparhawk, while traveling to work. A small amount of oil migrated over the surface to the adjacent pasture, owned by Paul & Lois Rydeen. Contaminated soil was hauled to an Enbridge storage facility at Clearbrook, but will likely be transported to the Mark II facility, in Fosston, for remediation. The leak site was relatively clean, with less than normal contaminated soil and trapped oil.

Enbridge initially imposed a voluntary pressure restriction on the Line 3 Clearbrook discharge of 80% of the maximum discharge pressure experienced within the preceding 15 days, equating to a new Base Maximum Discharge Pressure of 434 psig. The CD tool was mobilized shortly after, and run from Clearbrook to Superior. A tool failure resulted in only 72 km of data being retrieved, but it included the subject pipe joint, and the initial report from GE was that the defect was detected. Enbridge then began preparations for pipe replacement, to allow for further metallurgical evaluation of the defect, which was ultimately accomplished on November 28, 2007. A failure occurred near the completion of the replacement project, which resulted in another crude oil release, with subsequent ignition, and the deaths of two Enbridge employees. That accident is being investigated under MNPST Case #7751.

On December 14, 2007, Enbridge's Pipeline Integrity Department sponsored a conference call with PHMSA and MNPST to communicate the results of the CD tool run, and their plans for mitigating any other potential defects in the pipeline. Additional pressure restrictions were voluntarily imposed on U.S. Steel pipe downstream of Deer River, similar to the restrictions that were imposed downstream of Clearbrook. Analysis of the data and plans for assessing any reported defects are still in progress.

Enbridge also reported during the December 14, 2007 conference call that further analysis of the 2002 and 2005 CD tool data indicated that features were detected by the tool in both cases, but they did not meet the threshold reporting requirements. A substantial amount of additional analysis will need to be performed in order to determine whether the defect detection threshold is adequate, if defects are growing faster than anticipated by Enbridge, and the effects of removing the pressure restrictions that were in place following the Cohasset rupture, in order to validate the operational integrity of the pipeline.

MNPST anticipates additional inspection/investigation activities will be necessary in 2008, and will coordinate these activities with the PHMSA Central Region.

(2008 MNOPS Update)
On January 30, 2008 a meeting was held at the Central Region headquarters in Kansas City between Enbridge and PHMSA. MNOPS Inspector, Brian Pierzina, also attended. Enbridge representatives provided an Integrity Update which involved a wide range of factors, including an update of their Crack Management Program. Of particular interest, Enbridge mentioned they were moving towards using upper bounds of crack growth constants (C & n values), in an effort to address what appeared to by higher than estimated crack growth rates.

On March 28 and 31, 2008, Brian Pierzina made inquiries into a defect assessment that was planned at MP 1008, near the Grand Rapids High School. At this location, various defects including external corrosion, SCC, and mechanical damage were identified, which required repair. Ultimately MNOPS created a separate Case (#7930) for this project, and additional AFO Days associated with that project will be reported under Case #7930.

On April 9, 2008, Brian Pierzina met with Enbridge at their Superior Region headquarters in order to gather additional information relative to the initial failure investigation at MP 912.

On August 14, 2008, Brian Pierzina participated in a conference call with PHMSA Central Region and Enbridge representatives in which Enbridge provided an update of their crack management program as it relates to the 34 inch Line 3. Enbridge discussed preliminary considerations of an option that would involve replacement of 24 discreet pipeline segments, totaling approximately 150 miles system wide, or 14% of the overall length of the pipeline. Between Clearbrook and Superior, the length of pipeline under consideration is in the neighborhood of 30 – 40 miles. Several steps would be involved in the development of such a project. As stated, these were preliminary discussions of what was being considered/evaluated.

RECEIVED FEB 1 7 2009

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Brian E. Pierzina

<table>
<tr><th colspan="2">Inspection Report</th><th colspan="2">Post Inspection Memorandum</th></tr>
<tr><td rowspan="3">Inspector/Submit Date:</td><td rowspan="3">Brian Pierzina
02/03/2009</td><td colspan="2">Inspector/Submit Date: Brian Pierzina 02/03/2009</td></tr>
<tr><td colspan="2">Peer Reviewer/Date: 2/11/09</td></tr>
<tr><td colspan="2">Director Approval</td></tr>
<tr><th colspan="4">POST INSPECTION MEMORANDUM (PIM)</th></tr>
<tr><td>Name of Operator:</td><td colspan="2">Enbridge Energy Company, Inc.</td><td>OPID #: 11169</td></tr>
<tr><td>Name of Unit(s):</td><td colspan="2">Clearbrook to Deer River - IU 3083</td><td>Unit #(s): 3083</td></tr>
<tr><td>Records Location:</td><td colspan="3">219 N. 25th Street East, Superior, WI 54880</td></tr>
<tr><td>Unit Type & Commodity:</td><td colspan="3">Interstate Hazardous Liquid – Crude Oil</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Inspection Type:</td><td>Pipeline Failure – Material Defect</td><td colspan="2">Inspection Date(s): 1/29-31, 3/28,31, 4/9, 8/14/2008 ← NON-AFO</td></tr>
<tr><td>For OPS:</td><td colspan="2"></td><td>AFO Days:</td></tr>
<tr><td>For MNOPS:</td><td colspan="2">Brian Pierzina</td><td>AFO Days: BEP (4)</td></tr>
<tr><td colspan="3">MNOPS CASE #: 7715</td><td>NON AFO (1)</td></tr>
</table>

Synopsis: (Previously reported on PIM sent 01/09/2009) On November 13, 2007, Enbridge Energy discovered a crude oil leak near MP 912, approximately 3 miles southeast of the Clearbrook Terminal. The leak was discovered at approximately 7:00 AM by Enbridge electrician, Sam Sparhawk, as he was traveling to work. The leak was determined to be on the 34 inch Line 3, in the longitudinal weld seam of the pipe. The leak quantity was estimated by Enbridge as 2 bbls. The leak was initially repaired with a four foot long tight fitting repair sleeve, but an 11 foot section of pipe containing the defect was ultimately removed on November 28, 2007, to allow for further metallurgical evaluation. Prior to completing the replacement, a failure occurred, with subsequent ignition, resulting in the death of two Enbridge employees (MNOPS - Case #7751).

(Update 02/03/2009) This PIM has been prepared to account for MNOPS activities, particularly AFO Days, which occurred during 2008. The issues and potential mitigative actions associated with this Case, and the long seam defects associated with Enbridge's 34 inch Line 3 U.S. Steel pipe are still under consideration by Enbridge and PHMSA Central Region. It is expected this Case will remain open until formal plans for corrective action are adopted. For the time being, Enbridge has placed a pressure restriction on the U.S. Steel Pipe between Clearbrook and Superior.

Summary: (Previously Reported) At 8:22 AM, on November 13, 2007, Blake Olson, Supervisor of Enbridge's Clearbrook Terminal, notified the Duty Officer of a leak in a pasture, on County Road 3, about 3.5 miles east of Hwy 92. The leak was determined to be on Enbridge's 34 inch Line3, in the longitudinal weld seam of the pipe, and was repaired using a four foot long tight fitting repair sleeve.

The pipe at this location was manufactured by U.S. Steel, and is .344 inch wall – X-52. Ultrasonic inspection indicated an internally connected defect in the toe of the DSAW weld seam, with characteristics of a fatigue crack. Initial reports from Enbridge's Integrity Department were that there were no features reported at this location from either of the two previous CD tool runs, both of which were subsequent to the July 4, 2002 rupture near Cohasset.

The leak site was in the ditch on the south side of County Road 3, within Clearwater County ROW. It was initially detected by Enbridge electrician, Sam Sparhawk, while traveling to work. A small amount of oil migrated over the surface to the adjacent pasture, owned by Paul & Lois Rydeen. Contaminated soil was hauled to an Enbridge storage facility at Clearbrook, but will likely be transported to the Mark II facility, in Fosston, for remediation. The leak site was relatively clean, with less than normal contaminated soil and trapped oil.

Enbridge initially imposed a voluntary pressure restriction on the Line 3 Clearbrook discharge of 80% of the maximum discharge pressure experienced within the preceding 15 days, equating to a new Base Maximum Discharge Pressure of 434 psig. The CD tool was mobilized shortly after, and run from Clearbrook to Superior. A tool failure resulted in only 72 km of data being retrieved, but it included the subject pipe joint, and the initial report from GE was that the defect was detected. Enbridge then began preparations for pipe replacement, to allow for further metallurgical evaluation of the defect, which was ultimately accomplished on November 28, 2007. A failure occurred near the completion of the replacement project, which resulted in another crude oil release, with subsequent ignition, and the deaths of two Enbridge employees. That accident is being investigated under MNPST Case #7751.

On December 14, 2007, Enbridge's Pipeline Integrity Department sponsored a conference call with PHMSA and MNPST to communicate the results of the CD tool run, and their plans for mitigating any other potential defects in the pipeline. Additional pressure restrictions were voluntarily imposed on U.S. Steel pipe downstream of Deer River, similar to the restrictions that were imposed downstream of Clearbrook. Analysis of the data and plans for assessing any reported defects are still in progress.

Enbridge also reported during the December 14, 2007 conference call that further analysis of the 2002 and 2005 CD tool data indicated that features were detected by the tool in both cases, but they did not meet the threshold reporting requirements. A substantial amount of additional analysis will need to be performed in order to determine whether the defect detection threshold is adequate, if defects are growing faster than anticipated by Enbridge, and the effects of removing the pressure restrictions that were in place following the Cohasset rupture, in order to validate the operational integrity of the pipeline.

MNPST anticipates additional inspection/investigation activities will be necessary in 2008, and will coordinate these activities with the PHMSA Central Region.

(2008 MNOPS Update)
On January 30, 2008 a meeting was held at the Central Region headquarters in Kansas City between Enbridge and PHMSA. MNOPS Inspector, Brian Pierzina, also attended. Enbridge representatives provided an Integrity Update which involved a wide range of factors, including an update of their Crack Management Program. Of particular interest, Enbridge mentioned they were moving towards using upper bounds of crack growth constants (C & n values), in an effort to address what appeared to by higher than estimated crack growth rates.

On March 28 and 31, 2008, Brian Pierzina made inquiries into a defect assessment that was planned at MP 1008, near the Grand Rapids High School. At this location, various defects including external corrosion, SCC, and mechanical damage were identified, which required repair. Ultimately MNOPS created a separate Case (#7930) for this project, and additional AFO Days associated with that project will be reported under Case #7930.

On April 9, 2008, Brian Pierzina met with Enbridge at their Superior Region headquarters in order to gather additional information relative to the initial failure investigation at MP 912.

On August 14, 2008, Brian Pierzina participated in a conference call with PHMSA Central Region and Enbridge representatives in which Enbridge provided an update of their crack management program as it relates to the 34 inch Line 3. Enbridge discussed preliminary considerations of an option that would involve replacement of 24 discreet pipeline segments, totaling approximately 150 miles system wide, or 14% of the overall length of the pipeline. Between Clearbrook and Superior, the length of pipeline under consideration is in the neighborhood of 30 – 40 miles. Several steps would be involved in the development of such a project. As stated, these were preliminary discussions of what was being considered/evaluated.

Memorandum

U.S. Department
of Transportation
Pipeline and Hazardous
Materials Safety Administration | Central Region | Office of Pipeline Safety

Date: April 16, 2009

Subject: Incident Report, MNOPS System: Case #7715
Enbridge Energy Company, LP
Crude Oil Release
Clearbrook, MN to Deer River, MN – IU 3083
November 13, 2007

From: Hans Shieh, General Engineer

To: Ivan A. Huntoon, Director, Central Region, DPS-26

SUMMARY

En route to work on November 13, 2007, around 7:00am, an Enbridge employee observed a leak near MP 912, approximately 3 miles southeast of the Clearbrook Terminal. At 8:22am, Enbridge notified MNOPS that there was a leak in the pasture on County Road 3, about 3.5 miles east of Hwy 92. MNOPS case number is #7715. The investigation determined the leak was on Enbridge 34 inch, line 3, in the longitudinal weld seam of the pipe. The pipe was .344-inch wall x 52 and manufactured by U.S. Steel. Leak quantity was estimated at 2 bbls. The repair consisted of a four-foot long tight fitting repair sleeve.

Ultrasonic inspection indicated an internally connected defect in the toe of the double submerged arc weld (DSAW) seam, with characteristics of a fatigue crack. Enbridge imposed a voluntary pressure restriction on the Line 3 Clearbrook discharge of 80% of the maximum discharge pressure experienced within the preceding 15 days. This equated to a new Base Maximum Discharge Pressure of 434 psig. A crack detection tool was mobilized and run from Clearbrook, MN to Superior, WI that resulted in 72km of defects detected. Enbridge authorized a pipe replacement to perform a metallurgical evaluation of the defects. An 11 foot section of pipe containing the defect was removed and evaluated.

The pipe replacement project was near completion on November 28, 2007. However, a pipe failure released crude oil, caused a subsequent ignition, and then fatalities of two Enbridge employees. That accident is being investigated via MNOPS case #7751.

INVESTIGATION

The leak site was in the ditch of the south side of County Road 3, within Clearwater County ROW. A small amount of oil migrated over the surface to the adjacent pasture owned by private citizens. Contaminated soil was hauled to an Enbridge storage facility at Clearbrook, MN for pending remediation at the Mark II facility in Fosston, MN.

After a crack detection tool was run from Clearbrook, MN to Superior, WI, tool failure was detected around the subject pipe joint as well as other metallurgical findings. Enbridge placed a pressure restriction on the U.S. Steel manufactured pipe between Clearbrook, MN and Superior, WI until further notice. Corrective actions are warranted and under consideration by PHMSA Central Region and Enbridge. Prior Enbridge report data from 2002 and 2005 indicate that some similar defects that had been detected did not meet the threshold reporting requirements.

RECOMMENDATIONS

- Enbridge should perform a substantial amount of analysis to determine whether the defect detection threshold is adequate. There should be concern if defects are increasing too fast or the effects of removing the lowered pressure restrictions. A crack management program should be implemented.
- PHMSA should request copies of Enbridge's investigation, remediation, and any further actions taken to resolve this issue.
- MNOPS should collaborate with PHMSA Central Region to schedule future inspections, investigations, and long term monitoring of U.S. Steel manufactured 34" piping used in the Clearwater County, MN corridor.

RECEIVED MAR 2 0 2007

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	March 21, 2007	**Inspector:**	Boyd Haugrose
Peer Review/Date:		**Peer Reviewer:**	
Director Approval/Date:		**Director Approval**	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:**	11169
Name of Unit(s):	ND - Clearbrook "OPS 3083"	**Unit #(s):**	3803 3083
Records Location:	119 North 25th Street East, Superior, WI 54880		
Unit Type &Commodity: Hazardous Liquid Crude Oil			
Inspection Type:	Pipeline Failure – Natural Forces	**Inspection Date(s):**	2/5, 2/6 & 3/1/07
For OPS :		**AFO Days:**	
For MNOPS :	Boyd Haugrose	**AFO Days:**	3
MNOPS CASE #: 007175			

Summary:

On February 5, 2007, Enbridge Energy Company reported a 2 to 3 barrel crude oil leak at the Clearbrook station. The leak was discovered to be a cracked 1/2" Schedule 160 nipple on a block and bleed valve which is a part of the operational assembly of the Pressure Control Valve 2CSV22 on the discharge side of Unit 2. The Clearbrook Terminal is situated on ground that has an unusually high water table and as has happened in the past, the break was most likely caused by ground movement created by frost heaving. As remediation progressed it was determined that there were 10 barrels of crude oil recovered rather than the initial estimation of 2 - 3 barrels. The incident was not reported telephonically as it was believed the reporting thresholds were not met. Form 7000 was forwarded on February 28, 2007; a copy is stored in the docs tab of this case. The unit was placed back into service approximately 32 hours after discovery. No violations were identified, and no further actions are anticipated with respect to this incident.

Chronology of Events:

2/5/2007 - (PJD)

7:39 AM - DO (John Elder) - Al Aleknavicius (Cell # 218-591-2818 - Work 715-394-1415) Enbridge reported a 2 to 3 barrel crude oil leak at the Clearbrook station. Leak discovered at 6:45 AM this morning (2/5/07) Crude oil is contained in the sump, repair crew enroute. BEH to follow up.

2/5/2007 – (BEH)

Leak appears to be in sump on the discharge side of line 2. It appears to be of 2 -3 bbls at this time. The Bemidji PLM crew is enroute. The temperature in the area is -30 degrees F with wind chills in the - 55 -60 degree range.

If this is typical within the facility, there more than likely is a leaking pipefitting on a control line as has been the case many times previously. BEH will be in contact with Blake Olson, terminal manager, as the situation develops.

2/9/07 – (BEH)

On site observations on 2/5 and 2/6 resulted in the following dialogue:

The top of the water table at the Clearbrook station is typically only 2 - 3 feet deep. With -30 degree F temperatures, the frost levels are significant. This severely impacts recovery time for any underground leakage. This also contributes to such incidents. As suspected, the origin of the leak was in a control line for a block and bleed valve that was broken most likely from frost heave. This is not the first incident of leakage caused by the same issue. There have been a series of such incidents down through the years, as a result of frost heave against small threaded control lines. In this instance, released crude oil followed along the 24" pipeline under the frost cap until it found an avenue to rise to the surface. In this case the avenue was an inverted culvert around an underground control valve and piping that rose from the surface to a control shelter. Crude oil then became visible on the surface and within the shelter. It was discovered during routine morning rounds by Enbridge Employees. The unit (Line 2) was shut in and recovery operations began. Enbridge PLM crews were dispatched from Bemidji initially. The Enbridge vacuum truck was dispatched to pick up the crude oil. Later a second vac truck was dispatched from Minnesota Limited. PLM crews began jack hammering the soil to find the origin of the leak. Because of the extensive frost it became quickly apparent that more equipment was needed and Minnesota Limited provided a Bobcat with a hydraulic hammer and a track hoe, along with laborers to excavate the area. As time went on throughout the day it became apparent that progress was extremely slow, so PLM crews from Thief River Falls and Superior WI, as well as more personnel from Minnesota Limited were alerted to be on site to continue excavation throughout the night. Daylight on 2/6 revealed slow progress and the leak had not been found. During the excavation a large chunk of frozen soil broke off the bank and impacted on a block and bleed valve and broke it away from its piping. The piping was capped and excavation continued. By late afternoon, the source of the leak still had not been found.

At 3:30 PM, Blake Olson, the terminal manager, thought that perhaps the leak was in the piping surrounding the block and bleed valve that was broken by the falling soil. At this time, the valves surrounding the isolated piping were opened and crude oil was allowed back into the piping. The area was observed for 30 minutes for any indication of further leakage. None was apparent. At 4:00 PM, the unit was started up so that the area could be observed to see if there was any leakage while under pressure. After one hour there was no indication of leakage. It was determined that the leak occurred on the control line that broke away from the block and bleed valve.

Excavation was ended. Enbridge then deployed ground thawing equipment in the area so that soils remediation can begin. It is believed that the ground should be sufficiently thawed by 2/12/07 so that the contaminated soil can be removed. That soil will be stored at a spoils pile over plastic barriers until spring thaw when it will be removed to a soils farm facility for remediation.

The Enbridge personnel have not reported to NRC. They maintain no reporting criteria will be met. They believe there is less than 5 bbls of crude involved and they believe that the remediation costs will be less than $50,000.00.

3/1/07 BEH
An onsite interview was conducted with Blake Olson, EEC terminal manager. The Minnesota Pollution Control Agency (MPCA) has allowed EEC to suspend digging operations for fluid recovery until such a time that the ground is thawed. Mr. Olson states that 10 barrels of crude oil have been recovered. He believes that there will be only another trace to be recovered. Severe frost depths have hampered soil remediation.

3/13/07 BEH
A conference call was held with Jay Johnson, Mark Willoughby and Al Aleknaviscius with BEH for MNOPS. The call was to address concerns that have risen over the decision not to call the NRC to report the incident. Enbridge maintains the cost did not meet the reporting thresholds contrary to what may have been indicated by other personnel at the terminal. When it is all said and done the cost of recovery is $28,000.00 and the incident does not require notification to the NRC. EEC did report the incident on Form 7000 on February 28, 2007, however.

Memorandum

U.S. Department
of Transportation
Pipeline and
Hazardous Materials
Safety Administration

Central Region Office

Office of Pipeline Safety

Date: May 14, 2010

Subject: Accident – Enbridge Energy, LP
Line 14 – Atwood, WI
January 1, 2007

From: David Barrett – Director, Central Region

To: File

Summary

On the morning of January 1, 2007 a failure occurred on Enbridge's 24-inch Line 14 near Atwood, Wisconsin spilling approximately 1,500 barrels of crude oil. At the time of failure the pipeline was in a steady state operation when the Controller in Edmonton noted a sudden pressure drop at Owen Pump Station. In response to the pressure drop the Controller immediately shutdown Line 14 and sectionalized the line via remotely operated block valves. Local response personnel were notified, and the failure site was discovered at Milepost 149.44, approximately 3/4 mile downstream of Owen Station.

Responders acted to stop the flow of oil by excavating interceptor trenches in a drainage swale approx. ½ mile from the rupture location. The area of the failure was rural farm land, and was not in a high consequence area. No injuries, fatalities, or fire occurred as a result of the release.

The failed 24-inch diameter pipe was 0.328" w.t., API 5L-X70 with fusion bond epoxy coating, installed in 1998, and was manufactured by Stupp Pipe. A post-construction hydrostatic test was completed in August of 1998, and an inline inspection had been performed in 2006 using a geometry tool. The rupture was approximately 4 feet long and originated at the high frequency ERW long seam. The failed pipe was removed and transported to CC Technologies for metallurgical examination. Pre-tested 24-inch pipe, 0.375" w.t., API 5L-X70 pipe was used for replacement prior to the line returning to service at reduced pressure.

At the point of failure the pipeline was operating at 1,331 psig. Metallurgical analysis determined the rupture to be caused by a pre-existing lack of fusion defect in the ERW seam that grew by fatigue until failure. There was no observed evidence of other contributing factors to the failure.

Post-Accident Actions

Following the accident an 80% pressure restriction was placed on the entire Line 14. The pipeline was subsequently assessed using an ultrasonic crack detection tool, followed by excavation and repair.

Attachments

Form 7000-1 – Accident Report
Metallurgical Report by CC Technologies dated 03/13/2007

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122

Form Approved
OMB No. 2137-0047

U.S. Department of Transportaion
Research and Special Programs Administration

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date JAN 30,2007

No. 20070029 - 11612
(DOT Use Only)

INSTRUCTIONS

Important: ***Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov***

PART A - GENERAL REPORT INFORMATION check: ☐ Original Report ☒ Supplemental Report ☒ Final Report

1. a. Operator's OPS 5-digit Identification Number (if know) / 11169 /
2. b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if know) / /
   c. Name of Operator ENBRIDGE ENERGY, LIMITED PARTNERSHIP
   d. Operator street address 119 N 25TH STREET E
   e. Operator address SUPERIOR DOUGLAS WI 54880
   City, County, State and ZIP Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident
   / 830 / / 01 / / 01 / /2007 /
   hr. month day year
3. Location of accident
   (If offshore, do not complete a through d See Part C.1)
   a. Latitude: 44° 53' 27" Longitude: -90° 29' 50"
   (If not available, see instructions for how to provide specific location)
   b. ATWOOD CLARK
   City and County or Parish
   c. WI 54460
   State and Zip Code
   d. Mile post/valve station ● or Survey Station no. ○
   (whichever gives more accurate location)
   149.17
4. Telephone report
   / 822512 / / 01 / / 01 / / 2007 /
   NRC Report Number *month* *day* *year*

5. Losses (Estimated)

Public/Community Losses reimbursed by operator:

Public/private property damage	$ 0
Cost of emergency response phase	$ 0
Cost of environmental remediation	$ 0
Other Costs	$ 0
(describe)	

Operator Losses:

Value of product lost	$ 2,500
Value of operator property damage	$ 0
Other Costs	$ 700,000
(describe) REPAIR AND CLEANUP	
Total Costs:	$ 702,500

6. Commodity Spilled ● Yes ○ No
   (If Yes, complete Parts a through c where applicable)
   a. Name of commodity spilled ALBIAN HEAVY SYNTHETIC
   b. Classification of commodity spilled:
   ○ HVLs/other flammable or toxic fluid which is a gas at ambient conditions
   ○ CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditons
   ○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
   ● Crude oil

c. Estimated amount of commodity involved :

● **Barrels**
○ **Gallons (check only if spill is less than one barrel)**

Amounts :
Spilled : 1,500
Recovered: 1,450

CAUSES FOR SMALL SPILLS ONLY *(5 gallons to under 5 barrels)* **(For large spills [5 barrels or greater] see Part H)**

○ **Corrosion** ○ **Natural Forces** ○ **Excavation Damage** ○ **Other Ouside Force Damage**
○ **Materal and/or Weld Failures** ○ **Equipment** ○ **Incorrect Operation** ○ **Other**

PART B - PREPARER AND AUTHORIZED SIGNATURE

EMILY JURGENS
(type or print) Preparer's Name and Title

(715) 394-1547
Area Code and Telephone Number

EMILY.JURGENS@ENBRIDGE.COM
Preparer's E-mail Address

(715) 394-1500
Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Cod and Telephone Number

PART C - ORIGIN OF THE ACCIDENT *(Check all that apply)*

1. Additional location information
   a. Line segment name or ID 14
   b. Accident on Federal land other than Outer Continental Shelf ○ Yes ● No
   c. Is pipeline interstate? ● Yes ○ No

Offshore: ○ Yes ● No *(complete d if offshore)*
d. Area ______ Block # ______
State / / or Outer Continental Shelf ☐

2. Location of system involved (check all that apply)
- ☐ Operator's Property
- ☒ Pipeline Right of Way
- ☐ High Consequence Area (HCA)?
  Describe HCA ______

3. Part of system involved in accident
- ○ Above Ground Storage Tank
- ○ Cavern or other below ground storage facility
- ○ Pump/meter station; terminal/tank farm piping and equipment, including sumps
- ○ Other Specify: ______
- ● Onshore **pipeline**, including valve sites
- ○ Offshore **pipeline**, including platforms

If failure occurred on **pipeline**, *complete items a - g:*

4. Failure occurred on
- ○ Body of Pipe ● Pipe Seam ○ Scraper Trap
- ○ Pump ○ Sump ○ Joint
- ○ Component ○ Valve ○ Metering Facility
- ○ Repair Sleeve ○ Welded Fitting ○ Bolted Fitting
- ○ Girth Weld
- ○ Other *(specify)* ______

Year the component that failed was installed: / 1998 /

5. Maximum operating pressure (MOP)
   a. Estimated pressure at point and time of accident: 1,331 *PSIG*
   b. MOP at time of accident: 1,347 *PSIG*
   c. Did an overpressurization occur relating to the accident? ○ Yes ● No

a. Type of leak or rupture
- ○ Leak: ○ Pinhole ○ Connection Failure *(complete sec. H5)* ○ Puncture, diameter *(inches)* ______
- ● Rupture: ○ Circumferential - Separation ● Longitudinal - Tear/Crack, length *(inches)* 38
  Propagation Length, total, both sides *(feet)* 6
- ○ N/A
- ○ Other ______

b. Type of block valve used for isolation of immediate section:
- Upstream: ☐ Manual ☐ Automatic ☒ Remote Control ☐ Check Valve
- Downstream: ☐ Manual ☐ Automatic ☒ Remote Control ☐ Check Valve

c. Length of segment isolated 79,200 ft
d. Distance between valves 79,200 ft
e. Is segment configured for internal inspection tools? ● Yes ○ No
f. Had there been an in-line inspection device run at the point of failure? ● Yes ○ No ○ Don't Know ○ Not Possible due to physical constraints in the system
g. If Yes, type of device run *(check all that apply)*

Tool	Year run
☐ High Resolution Magnetic Flux tool	
☐ Low Resolution Magnetic Flux tool	
☐ UT tool	
☒ Geometry tool	2006
☐ Caliper tool	
☐ Crack tool	
☐ Hard Spot tool	
☐ Other tool	

PART D - MATERIAL SPECIFICATION

1. Nominal pipe size *(NPS)* / 24 / in.
2. Wall thickness .33 / in.
3. Specification API 5L X-70 SMYS / 70000 /
4. Seam type HF ERW
5. valve type ______
6. *Manufactured by* STUPP *in year* / 1998 /

PART E - ENVIRONMENT

1. Area of accident
- ○ Under pavement
- ● Underground
- ○ Inside/under building
- ○ In open ditch
- ○ Above ground
- ○ Under water
- ○ Other ______

2. Depth of cover: 60 *inches*

PART F - CONSEQUENCES

1. **Consequences *(check and complete all that apply)***

a.

	Fatalities	Injuries
Number of operator employees:	0	0
Contractor employees working for operator:	0	0
General public:	0	0
Totals:	0	0

b. Was pipeline/segment shutdown due to leak? ● Yes ○ No
If Yes, how long? 2 days 0 hours 4 minutes

c. Product ignited ○ Yes ● No d. Explosion ○ Yes ● No
e. ☐ **Evacuation** *(general public only)* / / people
Reason for Evacuation:
- ○ Precautionary by company
- ○ Evacuation required or initiated by public official

f. Elapsed time until area was made safe: / 2 / hr. / 30 / min.

2. **Environmental Impact**
   a. Wildlife Impact: Fish/aquatic ○ Yes ● No; Bird ○ Yes ● No; Terrestrial ○ Yes ● No
   b. Soil Contamination ● Yes ○ No
      If Yes, estimated number of cubic yards: 4,625
   c. Long term impact assessment performed: ● Yes ○ No
   d. Anticipated remediation ● Yes ○ No
      If Yes, Check all that apply: ☐ Surface water ☐ Groundwater ☒ Soil ☒ Vegetation ☐ Wildlife

e. Water Contamination: ○ Yes ● No *(If Yes, provide the following)*
Amount in water ______ barrels
- Ocean/Seawater ○ No ○ Yes
- Surface ○ No ○ Yes
- Groundwater ○ No ○ Yes
- Drinking water ○ No ○ Yes *(If Yes, check below.)* ○ Private well ○ Public water intake

PART G - LEAK DETECTION INFORMATION

1. Computer based leak detection capability in place? ● Yes ○ No
2. Was the release intially detected by? (check one):
   - ○ CPM/SCADA-based system with leak detection
   - ○ Static shut-in test or other pressure or leak test
   - ○ Local operating personnel, procedures or equipment
   - ● Remote operating personnel, including controllers
   - ○ Air patrol or ground surveillance
   - ○ A third party ○ Other (specify) ______
3. Estimated leak duration days 0 hours 0

PART H - APPARENT CAUSE

Important: There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. Secc the instructions for guidance.

H1 - CORROSION

1. ○ External Corrosion
2. ○ Internal Corrosion

(Complete items a - e where applicable.)

a. Pipe Coating
○ Bare
○ Coated

b. Visual Examination
○ Localized Pitting
○ General Corrosion
○ Other ______

c. Cause of Corrosion
○ Galvanic ○ Atmospheric
○ Stray Current ○ Microbiological
○ Cathodic Protection Disrupted
○ Stress Corrosion Cracking
○ Selective Seam Corrosion
○ Other ______

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
○ No ○ Yes, Year Protection Started: /______/

e. Was pipe previously damaged in the area of corrosion?
○ No ○ Yes => Estimated time prior to accident: /__/ years /__/ months Unknown ☐

H2 - NATURAL FORCES

3. ○ Earth Movement =>○ Earthquake ○ Subsidence ○ Landslide ○ Other ______
4. ○ Lightning
5. ○ Heavy Rains/Floods =>○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other ______
6. ○ Temperature =>○ Thermal stress ○ Frost heave ○ Frozen components ○ Other ______
7. ○ High Winds

H3 - EXCAVATION DAMAGE

8. ○ Operator Excavation Damage (including their contractors/Not Third Party)
9. ○ Third Party *(complete a-f)*

a. Excavator group
○ General Public ○ Government ○ Excavator other than Operator/subcontractor

b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable
○ Landowner-not farming related ○ Farming ○ Raildroad
○ Other liquid or gas transmission pipeline-operator or their contractor
○ Nautical Operations ○ Other ______

c. Excavation was: ○ Open Trench ○ Sub-strata (boring, directional drilling, etc...)

d. Excavation was an ongoing activity (Month or longer) ○ Yes ○ No If Yes, Date of last contact /__/

e. Did operator get prior notification of excavation activity?
○ Yes; Date received: /__/mo. /____/ day /__/ yr. ○ No

Notification received from: ○ One Call System ○ Excavator ○ Contractor ○ Landowner

f. Was pipeline marked as result of location request for excavation? ○ No ○ Yes (If Yes, check applicable items i - iv)
i. Temporary markings: ○ Flags ○ Stakes ○ Paint
ii. Permanent markings: ○ Yes ○ No
iii. Marks were (check one) : ○ Accurate ○ Not Accurate
iv. Were marks made within required time? ○ Yes ○ No

H4 - OTHER OUTSIDE FORCE DAMAGE

10. ○ Fire/Explosion as primary cause of failure => Fire/Explosion cause: ○ Man Made ○ Natural
11. ○ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ○ Rupture of Previously Damaged Pipe
13. ○ Vandalism

H5 - MATERIAL AND/OR WELD FAILURES

Material

14. ○ Body of Pipe =>○ Dent ○ Gouge ○ Bend ○ Arc Burn ○ Other ______

15. ○ Component =>○ Valve ○ Fitting ○ Vessel ○ Extruded Outlet ○ Other ______

16. ○ Joint =>○ Gasket ○ O-Ring ○ Threads ○ Other ______

Weld

17. ○ Butt =>○ Pipe ○ Fabrication ○ Other ______

18. ○ Fillet =>○ Branch ○ Hot Tap ○ Fitting ○ Repair Sleeve ○ Other ______

19. ● Pipe Seam =>○ LF ERW ○ DSAW ○ Seamless ○ Flash Weld
● HF ERW ○ SAW ○ Spiral ○ Other ______

Complete a-g if you indicate any cause in part H5.

a. Type of failure:
○ Construction Defect => ○ Poor Workmanship ○ Procedure not followed ○ Poor Construction Procedures
● Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? ○ Yes ● No

c. Was part which leaked pressure tested before accident occurred? ● Yes, complete d-g ○ No

d. Date of test: / 1998 / yr. / 8 / mo. / 31 / day

e. Test medium: ● Water ○ Inert Gas ○ Other ______

f. Time held at test pressure: / 8 / hr.

g. Estimated test pressure at point of accident: 1804 *PSIG*

H6 - EQUIPMENT

20. ○ Malfunction of Control/Relief Equipment => ○ Control valve ○ Instrumentation ○ SCADA ○ Communications
○ Block valve ○ Relief valve ○ Power failure
○ Other ______

21. ○ Threads Stripped Broken Pipe Coupling => ○ Nipples ○ Valve Threads ○ Dresser Couplings
○ Other ______

22. ○ Seal Failure =>○ Gasket ○ O-Ring ○ Seal/Pump Packing
○ Other ______

H7 - INCORRECT OPERATION

23. ○ Incorrect Operation

a. Type ○ Inadequate Procedures ○ Inadequate Safety Practices ○ Failure to Follow Procedures
○ Other ______

b. Number of employees involved who failed a post-accident test: drug test: / / alcohol test / /

H8 - OTHER

24. ○ Miscellaneous, *describe:* ______

25. ○ Unknown
○ Investigation Complete ○ Still Under Investigation (*Submit a supplemental report when investigation is complete*)

PART I - NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT

(Attach additional sheets as necessary)

AT APPROXIMATELY 0830 MST, A CALL WAS RECEIVED FROM THE EDMONTON CONTROL CENTER THAT THERE WAS A PRESSURE LOSS AT OWEN STATION. THE PIPELINE WAS IMMEDIATELY SHUT DOWN AND THE VESPER PLM CREW WAS NOTIFIED AND RESPONDED TO OWEN STATION. AT 1100 MST, THE LEAK WAS CONFIRMED BY VESPER PLM AND ADDITIONAL VESPER AND FORT ATKINSON PLM CREWS MOBILIZED MANPOWER AND EMERGENCY RESPONSE EQUIPMENT TO THE LEAK SITE. SUPERIOR AND BEMIDJI PLM CREWS WERE ALSO NOTIFIED AND BEGAN TO MOBILIZE MANPOWER AND EQUIPMENT. AN OPS INSPECTOR ARRIVED ON SITE JANUARY 2, 2007 AND WITNESSED THE REPAIR.

FINAL REPORT

80 7002 02

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
SUPERIOR, WISCONSIN

METALLURGICAL FAILURE ANALYSIS OF RUPTURED PIPELINE FROM LINE 14 AT MILEPOST US 149.4

FINAL REPORT
80 7002 02

METALLURGICAL FAILURE ANALYSIS OF RUPTURED PIPELINE FROM LINE 14 AT MILEPOST US 149.4

PREPARED FOR
ENBRIDGE ENERGY, LIMITED PARTNERSHIP
SUPERIOR, WISCONSIN

PREPARED BY
CC TECHNOLOGIES, INC.
BRETT M. TOSSEY, B.S.
JOHN A. BEAVERS, PHD.

MARCH 13, 2007

CC Technologies
A DNV COMPANY
Innovative Solutions
5777 FRANTZ ROAD
DUBLIN, OHIO 43017
614.761.1214 • 614.761.1633 fax
www.cctechnologies.com

SIGNATURE PAGE

Metallurgical Failure Analysis of Ruptured Pipeline Removed from Line 14 at Milepost US 149.4

AUTHOR:

Brett M. Tossey
Project Engineer

Brett M. Tossey

Date 03-13-2007

REVIEWED BY:

John A. Beavers
Director – Failure Analysis

John A Beavers

Date 03-13-2007

APPROVED BY:

Oliver C. Moghissi
Senior VP – Laboratories

Oliver C. Moghissi

Date 03-13-2007

80 7002 02 (raa) Q:\EAWUS813\Anderson\BRETT TOSSEY\ENBRIDGE (80 7002 02)\Enbridge Final Report (80 7002 02) (March 13).doc

DISCLAIMER

This report documents work performed by CC Technologies, Inc. *(CC Technologies)* Dublin, Ohio, for Enbridge Energy, Limited Partnership, Superior, Wisconsin. Neither CC Technologies nor any person acting on behalf of CC Technologies:

- assumes any liability for consequences or damages resulting from the use, misuse, or reliance upon the information disclosed in this report.
- makes any warranty or representations that the use of any information, apparatus, method, or process disclosed in this report may not infringe on privately-owned rights.

EXECUTIVE SUMMARY

CC Technologies, Inc. (*CC Technologies*) was retained by Enbridge Energy, Limited Partnership (*Enbridge*) to perform a metallurgical analysis on a section of pipe from the 24-inch diameter crude oil pipeline that failed during operation. The failure occurred on January 1, 2007 near Owen, Wisconsin on Line 14 at milepost (MP) US 149.4, 0.7 miles downstream (D/S) of the nearest pump station.

The portion of the pipeline containing the failure is comprised of 24-inch diameter by 0.328-inch wall thickness, API 5L X70 line pipe that was manufactured by Stupp Corporation and contains an electric resistance welded (ERW) longitudinal seam. The maximum allowable operating pressure is 1,377 psig, which corresponds to 72% of the specified minimum yield strength (SMYS). The pressure at the time and location of the failure was 1331 psi, which corresponds to 69.6% of SMYS (96.6% of MAOP).

The pipe was installed in 1998 and was reportedly externally coated with fusion bonded epoxy coating. Following construction, a hydrostatic test to 1836 psig (96% SMYS) was performed.

The pipe section was visually examined and photographed in the as-received condition. Transverse tensile and Charpy V-notch impact specimens were removed from across the weld and from the base metal 180° circumferentially from the longitudinal seam weld. Samples for chemical analysis were also removed from the upstream joint and the failure joint. The external surface along the longitudinal seam weld was cleaned with a wire brush to remove the fusion bonded epoxy coating, and the internal surface was degreased with a citrus based organic solvent. Black and white magnetic particle inspection (BWMPI) and ultrasonic inspection were performed on the electrical resistance weld (ERW) to identify any defects or anomalies. Cross-sections were removed from two locations on the fracture face and one location from a non-damaged portion of the ERW seam for metallographic examination. The cross-sections were mounted, polished, and photomicrographs were taken using a light microscope. The mating fracture surfaces containing the suspected failure origin were photographed and one half of the fracture surface was cleaned with inhibited acid and a soft bristle brush. The other half was degreased only. A scanning electron microscope (SEM) was used for the fractographic examination on the cleaned and degreased fracture faces.

The following are the findings from the failure analysis.

- An ID surface breaking defect was present at the origin of the failure.
- The defect was located at the ERW seam weld adjacent to the upstream girth weld.
- There is evidence that the defect grew in service by a fatigue mechanism.
- There is evidence of cleavage in the fast fracture zone between the lack of fusion (LOF) flaw and the OD pipe surface at the bond line, indicating low toughness of the ERW seam.
- Away from the failure origin, the seam weld has good mechanical properties and met API specifications.
- The mechanical properties of the base metal met API specifications and had good toughness.
- The chemical composition of the base metal met API specifications.

The findings indicate that a pre-existing ID surface breaking flaw, located at the ERW seam weld, grew in service by a fatigue mechanism. The rupture initiated at this defect when the flaw size exceeded the critical flaw size for the material properties, dimensions, and operating pressure.

CONTENTS

TABLES

FIGURES

FIGURES (continued)

INTRODUCTION

CC Technologies, Inc. (CC Technologies) was retained by Enbridge Energy, Limited Partnership (Enbridge) to perform a metallurgical analysis on a section of pipe from the 24-inch diameter crude oil pipeline that failed during operation. The failure occurred on January 1, 2007 near Owen, Wisconsin on Line 14 at milepost (MP) US 149.4, 0.7 miles downstream (D/S) of the nearest pump station.

The portion of the pipeline containing the failure is comprised of 24-inch diameter by 0.328-inch wall thickness, API 5L X70 line pipe that was manufactured by Stupp Corporation and contains an electric resistance welded (ERW) longitudinal seam. The maximum allowable operating pressure is 1,377 psig, which corresponds to 72% of the specified minimum yield strength (SMYS). The pressure at the time and location of the failure was 1331 psi, which corresponds to 69.6% of SMYS (96.6% of MAOP).

The pipe was installed in 1998 and was reportedly externally coated with fusion bonded epoxy coating. Following construction, a hydrostatic test to 1836 psig was performed.

PROCEDURES

The procedures used in the analysis were in accordance with industry accepted standards. Six of the general standards governing terminology, chemical analysis, mechanical testing, and specific metallographic procedures used are as follows:

- ASTM E3, "Standard Methods of Preparation of Metallographic Specimens."
- ASTM E7, "Standard Terminology Relating to Metallography."
- ASTM E8, "Test Methods for Tension Testing of Metallic Materials."
- ASTM E23, "Standard Test Methods for Notched Bar Impact Testing of Metallic Materials."
- ASTM G15, "Standard Terminology Relating to Corrosion and Corrosion Testing."
- ASTM A751, "Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products."

Figure 1 is a schematic of the pipe section showing the location of the rupture, the longitudinal seam weld, the reference upstream girth weld (RUGW), and where the samples for chemical analysis, mechanical testing (Charpy curve and duplicate tensiles), metallographic analysis, and fractographic analysis were removed. The following steps were performed for this analysis. The pipe section was visually examined and photographed in the as-received condition. Transverse tensile and Charpy V-notch impact specimens were removed from across the weld and from the base metal 180° circumferentially from the longitudinal seam weld. Samples for chemical analysis were also removed from the upstream pup and the failure joint. The external surface along the longitudinal seam weld was cleaned with a wire brush to remove the fusion bonded epoxy coating, and the internal surface was degreased with a citrus based organic solvent. Black and white magnetic particle inspection (BWMPI) and ultrasonic inspection were performed on the electrical resistance weld (ERW) to identify any defects or anomalies. Cross-sections were removed from two locations on the fracture face and one location from a non damaged portion of the ERW seam for metallographic examination. The cross-sections were mounted, polished, and photomicrographs were taken using a light microscope. The mating fracture surfaces containing the suspected failure origin were photographed and one half of the fracture surface was cleaned with inhibited acid and a soft bristle brush. The other half was degreased only. A scanning electron microscope (SEM) was used for the fractographic examination on the inhibited acid cleaned and degreased fracture faces.

RESULTS AND DISCUSSION

Optical Examination

Figure 2 is a photograph of the pipe section in the as-received condition. The flow direction and top dead center (TDC) were indicated on the pipe section. The flow direction, seam weld location, and location of the rupture are indicated in the figure. The external coating was disbonded in the vicinity of the rupture due to plastic deformation of the pipe steel. The total length of the rupture was approximately 50 inches.

The seam weld was located at the 2:00 orientation (looking downstream [D/S]), approximately 12.5-inches clockwise of TDC. Figure 3 is a photograph of the fracture face after removing the protective rubber hose and the grease. The flow direction is indicated in the figure. Figure 4 is a photograph of the API label found on the inside surface of the pipe after degreasing. The label was approximately ten inches downstream of the RUGW. The label text from the pipe is shown on the left below, while the mill record text is shown on the right.

STUPP SL-0006 API	Stupp 5L-0006 API
1-9824.00	Date______ 24.00
2.92 X70 E	89.92 X 70 E
TESTED 1910	TESTED 1910
R17	SR 17
R5 AB-35-M40F	SR5AB-35-M40F
R6-M40F M1	SR6M40F MI
0 999-63-6218	P.O. 999-63-6218-97
R 7798.328	ER7798 .328

The circumference of the pipe section was measured to obtain a diameter of twenty-four inches. The wall thickness was measured at the 12, 3, 6, and 9 o'clock orientation at the U/S pipe section end. The average wall thickness of 0.330-inches is consistent with a nominal wall thickness of 0.328-inches, and the reading ranged form 0.328 inches to 0.334 inches.

Magnetic Particle Inspection (MPI)

MPI was performed in the vicinity of the seam weld (6" on either side) over the unruptured length of the ERW in the ruptured pipe section. No anomalies were identified in the region that MPI was performed.

Ultrasonic Inspection (UT)

UT inspection was performed on the pipe section beginning at 4.6 feet from the RUGW (approximately 0.5 inches from the downstream end on the rupture) to the downstream cut end of the pipe. The results of the UT inspection showed a low amplitude signal from the ERW at a point 4.6 feet downstream of the RUGW to a point 7.5 feet downstream of the RUGW. The inspector noted a region on the inside surface of pipe that was visibly under trimmed and aligned with the ERW. The low amplitude signal was attributed to either the protruding metal left attached to the inside surface along the ERW or possibly a sharp longitudinal groove in the middle of the protruding metal.

Fractographic Examination

Both fracture faces were saw-cut from the pipe to analyze the fracture surfaces. Figures 5, Figure 6, and Figure 7 are photographs of the fracture surfaces contained in the ERW seam.

Figure 5 was obtained from the suspected rupture origin and shows three distinctly different zones on the fracture surface at the intersection of the ERW and the RUGW to four inches downstream of the RUGW. Metallographic sections were not cut from this area in order to preserve the fracture surfaces. The photograph shows: a black zone at the ID surface, a smooth gray zone in the middle of fracture face that terminated 3.2 inches form the RUGW, and another roughened gray zone from approximately mid wall to the outside surface. Figure 6 is a representative photograph of the fracture surface between 14 inches and 17.3 inches from the RUGW. The photograph shows only two zones, the intermittent black and gray zone that is connected with the pipe ID and the roughened gray zone near the pipe OD. The fracture face morphology shown in Figure 6 continued to 36.8 inches from the RUGW, where the ID connected defect ceased to exist. Figure 7 shows the same features as seen in Figure 6 and the point where the fracture changed from brittle fast fracture to ductile shear (indicated on the figure).

In summary, the fracture face contained a continuous ID connected flaw that was 36.8 inches long, varied in depth along the fracture surface, and appeared to be a lack of fusion (LOF) defect. Detailed depth measurements were taken on the flaw to generate a flaw profile, see Figure 8. The black vertical line positioned at 3.19 inches in the figure indicates the region where the fracture face transitions from three distinct zones to two zones. The black zone and light grey zone are labeled to in the figure. The maximum flaw depth was 0.200 inches deep (66.7% through wall) and was located 1.36 inches from the RUGW. The average depth of the black zone was 0.044 inches, and the depth measurements ranged from 0.019 inches to 0.130 inches.

Metallographic Examination

Opposing portions of the fracture face and a portion of the non damaged ERW were removed for metallographic analysis removed at the locations shown in Figure 1. Figure 9 and Figure 10 shows photographs of metallographic mounts (A1 and A2). In both mounts there is evidence that the ERW trim tool was misaligned and the ID surface of the pipe was trimmed in the pipe body rather than on the ERW seam. The trimmed area is indicated by an arrow in each figure. The trim tool misalignment did not influence the pipe rupture.

Figure 11 is a light photomicrograph of the typical microstructure of the base metal. The microstructure consists of ferrite (white areas), and pearlite (dark areas consisting of lamellae). This microstructure is typical for the grade and vintage of line pipe steel.

Figure 12 is a light photomicrograph of Mount A1 showing the through wall fracture at 25X. The ID connected LOF and the area of fast fracture are indicated in the figure. The grain structure along the bond line in the LOF zone and the fast fracture zone showed little or no plastic deformation. Grain deformation and evidence of ductility was observed near the OD of the sample. The LOF zone, fast fracture zone, and the ductile tearing zone are labeled in the figure. The area inside each white box is expanded to 400X in the right hand side of the figure to reveal the microstructure in each zone.

Figure 13 is a light photomicrograph of mount A2 showing the ERW 59 inches from the RUGW in an undamaged portion of the pipe. The HAZ is evident and no LOF defect is evident at this location. This is the same region where the excessive metal was noted on the inside surface of the pipe during the UT inspection. No sharp longitudinal flaw was evident in the ERW seam. Microhardness measurements were collected in the base metal, in the HAZ, and on the ERW bond line. The measurements ranged from 223 Knoop (95 Rockwell B) to 163 Knoop (22 Rockwell C). The hardness on the bond line was 171 Knoop (98 Rockwell B) and the highest reading from the HAZ adjacent to the bond line was 163 Knoop (23 Rockwell C). The microstructure in the HAZ and at the bond line, as well as the hardness of the HAZ and the bond line, are consistent with a normalized ERW seam.

Scanning Electron Microscopy

Figure 14 is a stereo light photomicrograph showing one-half of the fracture surface from 0 inches from the RUGW to 3.5 inches from the RUGW. This is the area of the suspected origin of the rupture. The three zones are readily apparent on the fracture surface; a dark ID connected zone, a lighter, smoother zone adjacent to the dark zone and an OD connected rougher zone. Also shown in Figure 14 are the locations where SEM photographs were taken.

Figure 15 is an SEM photograph of the surface in the dark ID connected zone. The morphology in this zone is consistent with a lack of fusion (LOF) defect, consisting of a flat, non-descript surface with no signs of metallurgical bonding. Figure 16 is a representative SEM photograph of the fracture surface in the lighter smooth zone adjacent to the LOF defect. Markings were present on the fracture surface in this zone that are consistent with fatigue striations (arrows shown in the figure). Fatigue striations are remnants of the progressive positions of the fatigue fracture surface as the fatigue crack propagates through the material.

Figure 17 is a representative SEM photograph of the rougher zone on the fracture surface near the OD of the pipe. The fractography is characteristic of rapid brittle cleavage fracture that occurs in steels with low toughness. Figure 18 is an SEM photograph of an intergranular zone in the transition regions separating the LOF zone and the fatigue zone adjacent to the upstream girth weld.

Chemical Analysis

The results of the chemical analysis conducted on the samples cut from the pipe section are summarized in Table 1. The results of the analysis are consistent with the chemical composition specifications for API 5L X70 line pipe in place at the time of manufacture.

Mechanical Test Results

Results of the tensile testing are shown in Table 2. The yield strength (YS) and ultimate tensile strength (UTS) of the failure joint base metal were determined to be 77.25-ksi and 90.25-ksi, compared with specified minimum YS and UTS of 70.0-ksi and 82.0-ksi, respectively. Thus, the tensile properties met the minimum YS and UTS specification for API 5L X70 line pipe steel in place at the time of manufacture.

Tables 3-6 summarize the results of the Charpy testing while Figures 18-25 show the Charpy percent shear and impact energy curves. An analysis of these data, which is shown in Table 7, indicated that the 85% fracture appearance transition temperature (FATT) and upper shelf energy for the weld metal (WM) and base metal (BM) of the U/S joint were > 95°F and > 95 ft-lbs and 43.7°F and 143.0 ft-lbs, respectively. The 85%

FATT and upper shelf Charpy energy for the WM and BM in the D/S failure joint were 77.3°F and 137.0 ft.-lbs and 39.0°F and 116.3 ft.-lbs, respectively.

The CVN test results can be adjusted to account for static initiation and material constraint effects by applying temperature shifts to the data,[1] see Table 7. The modified transition temperatures (brittle-to-ductile fracture initiation temperature) were estimated as > 95°F , 12.6°F, 46.1°F, and 7.9°F for the WM of the U/S joint, the BM of the U/S joint, the WM of the failure joint, and the BM of the failure joint, respectively for each pipe joint and thickness of 0.330. The data indicate that the base metal had toughness properties that well exceeded the 20 ft-lbs specified in API 5L. The weld metal had high toughness, but also had a relatively high transition temperature. However, the toughness below the transition temperature was relatively high. A high toughness is indicative of good fracture resistance.

CONCLUSIONS

The following conclusions resulted from the failure analysis.

- The rupture initiated at an ID surface breaking defect located at the ERW seam weld adjacent to the upstream girth weld.
- There is evidence that the defect grew in service by a fatigue mechanism.
- There is evidence of cleavage in the fast fracture zone between the LOF flaw and the OD pipe surface at the bond line, indicating low toughness of ERW seam.
- Away from the failure origin, the seam weld has good mechanical properties and met API specifications.
- The mechanical properties of the base metal met API specifications and had good toughness.
- The chemical composition of the base metal met API specifications.

The results of the failure analysis show that a pre-existing ID surface breaking flaw grew in service by a fatigue mechanism. The rupture occurred when the flaw size exceeded the critical flaw size for the material properties, dimensions, and operating pressure.

1 "A Simple Procedure for Synthesizing Charpy Impact Energy Transition Curves from Limited Data," Michael J. Rosenfeld, International Pipeline Conference – Volume 1, ASME 1996, p.216.

Table 1. Chemical analysis results from failure joint and upstream pup.

Element		X70 – PSL 2 [a] (1995)	Failure Joint Wt. %	Upstream Pup Wt. %
C	(Carbon)	0.22 max.	0.064	0.062
Mn	(Manganese)	1.85 max	1.53	1.53
P	(Phosphorus)	0.025 max.	0.016	0.014
S	(Sulfur)	0.015 max.	0.006	0.005
Si	(Silicon)	–	0.207	0.209
Cu	(Copper)	–	0.018	0.016
Sn	(Tin)	–	0.004	0.004
Ni	(Nickel)	–	0.022	0.020
Cr	(Chromium)	–	0.029	0.027
Mo	(Molybdenum)	–	0.006	0.006
Al	(Aluminum)	–	0.022	0.028
V	(Vanadium)	–	0.035	0.036
Nb	(Niobium)	–	0.049	0.052
Zr	(Zirconium)	–	0	0.001
Ti	(Titanium)	–	0.016	0.016
Ca	(Calcium)	–	0.016	0.0037
Co	(Cobalt)	–	0.004	0.004
Fe	(Iron)	–	0	Balance
NB + V + Ti		< 0.15	0.10	0.10

[a] API 5L Specification for Line Pipe, 41st Edition, 1995.

Table 2. Tensile test results from failure joint and upstream pup.

	X70–PSL 2 [a] Minimum & Maximum	Base Metal Ruptured Joint	Transverse Weld Sample Ruptured Joint	Base Metal U/S Joint	Transverse Weld Sample U/S Joint
Yield Strength, ksi	70 : 90	77.25	–	80	–
Tensile Strength, ksi	82 : 110	90.25	101.5	95.5	101.25
Elongation, %	20.5 [b]	30	–	30	–

[a] API 5L Specification for Line Pipe, 41st Edition, 1995.

[b] Based on calculation $e = 625{,}000 \frac{A^{0.2}}{U^{0.9}}$, where A is the tensile specimen cross sectional area in square inches and U is the specified minimum tensile strength in psi.

Table 3. Charpy V-notch test results for samples removed from the upstream joint (weld metal).

Sample ID	Temperature, °F	Sub-Sized Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, % *
1	-43	12.5	17.7	0
2	-18	33.0	46.8	10
3	7	54.0	76.5	15
4	32	67.3	67.3	30
5	44	77.9	77.9	35
6	57	93.5	93.5	40
7	82	95.0	95	55

* Determined from sub-sized specimens.

Table 4. Charpy V-notch test results for samples removed from the upstream joint (base metal).

Sample ID	Temperature, °F	Sub-Sized Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, % *
1	-93	13.5	18.3	10
2	-68	37.5	50.8	35
3	-43	49.0	66.3	80
4	-18	72.0	97.5	80
5	7	64.0	86.7	65
6	32	97.0	131.3	75
7	57	84.0	113.7	85
8	90	109.0	147.6	75

* Determined from sub-sized specimens.

Table 5. Charpy V-notch test results for samples removed from the failure joint (weld metal).

Sample ID	Temperature, °F	Sub-Sized Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, % *
1	-18	8.5	12.1	0
2	7	55	78.5	15
3	32	70	99.9	35
4	57	71	101.4	55
5	82	99	141.3	100

* Determined from sub-sized specimens.

Table 6. Charpy V-notch test results for samples removed from the failure joint (base metal).

Sample ID	Temperature, °F	Sub-Sized Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, % *
1	-93	52	69.5	35
2	-68	60	80.1	70
3	-43	59	78.8	70
4	-18	72	96.2	75
5	7	110	146.9	75
6	32	82	109.5	80
7	57	82	109.5	80
8	90	78	104.2	95

* Determined from sub-sized specimens.

Table 7. Results of the Charpy V-notch impact energy and percent shear plots for the base metal and weld metal of the upstream and downstream joints.

	U/S Weld Metal	U/S Base Metal	Failure Joint Weld Metal	Failure Joint Base Metal
Upper Shelf Impact Energy (Full Size), Joules	>95	143.8	137.0	116.3
85% FATT, °F	>95	43.7	77.3	39.0
Maxey Adjusted 85% FATT, °F	>95	12.6	46.1	7.9

* Determined from sub-sized specimens.

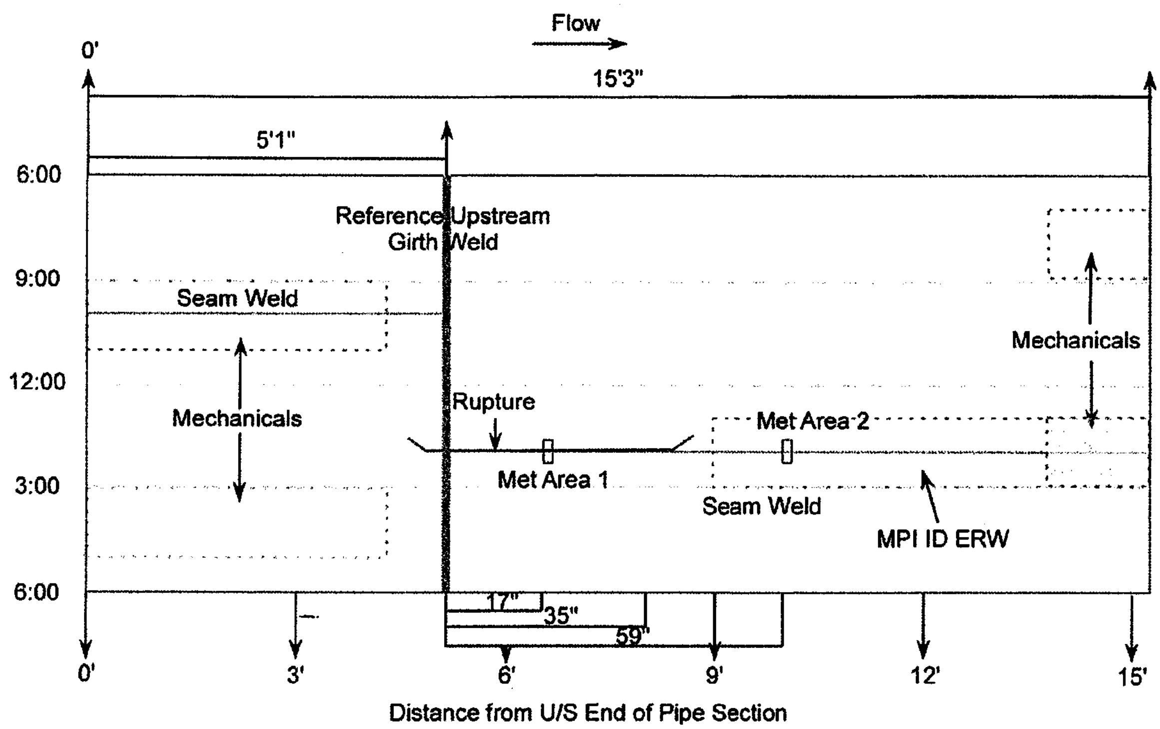


Figure 1. Schematic of the 24-inch diameter pipe section removed from Line 14 at MP US 149.4, showing the locations where the samples were removed.

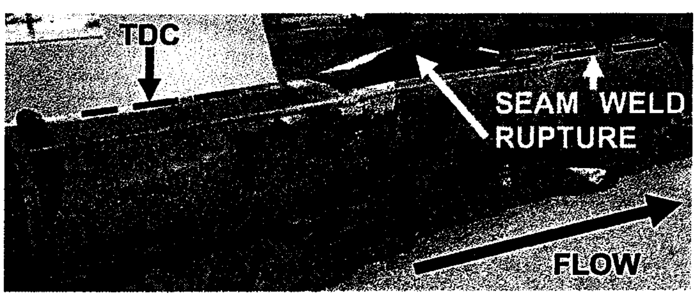


Figure 2. Photograph of the 24-inch diameter pipe section removed from Line 14 at MP US 149.4 in the as-received condition.

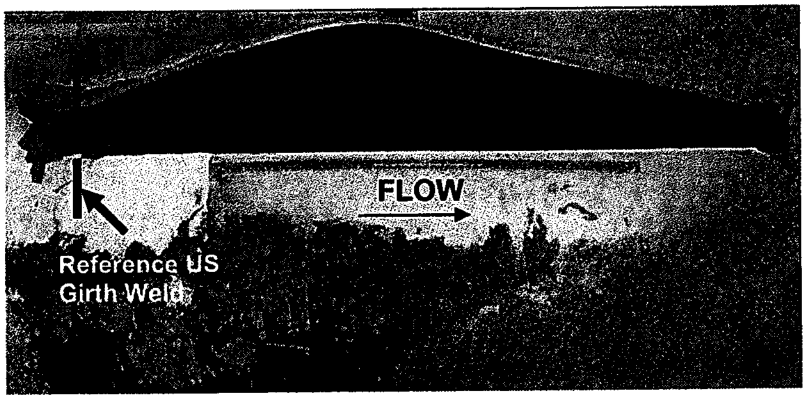


Figure 3. Photograph of the rupture on the pipe section after removing the protective rubber and grease.

Figure 4. Photograph of the API label found near the upstream girth weld on the inside surface of the ruptured pipe section.

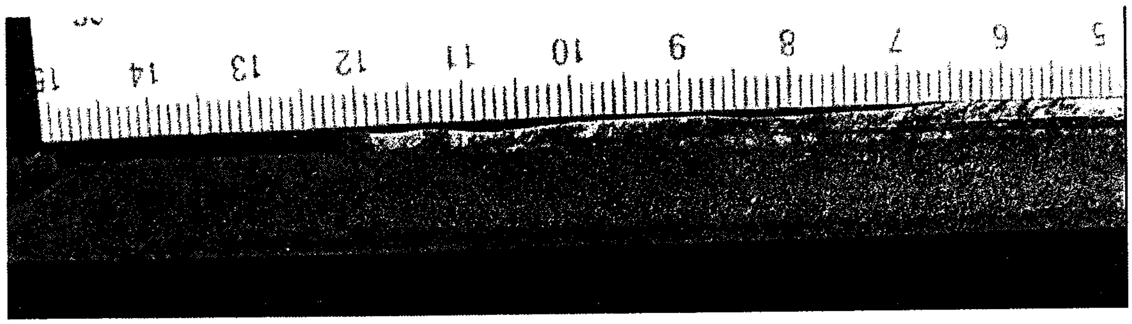


Figure 5. Photograph of the fracture face from 0 inches to 4 inches from the reference upstream girth weld.

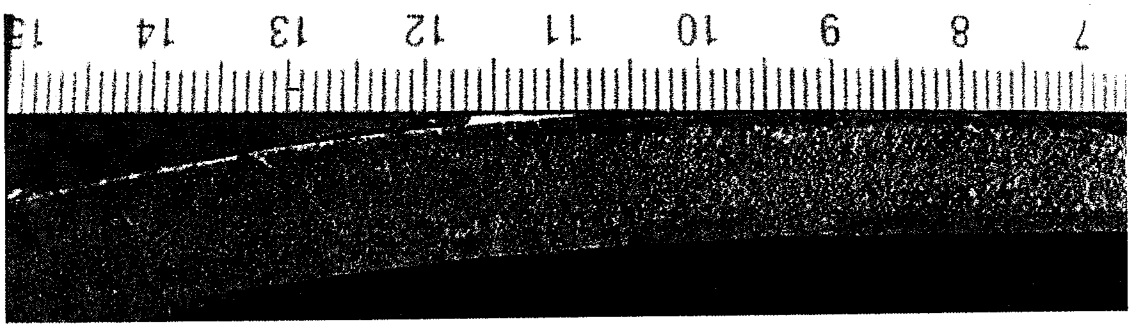


Figure 6. Photograph of the fracture face from 14 inches to 17.3 inches from the reference upstream girth weld.

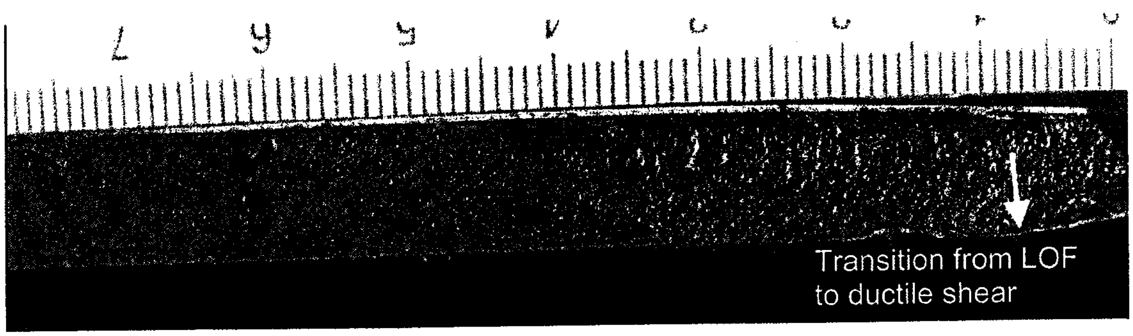


Figure 7. Photograph of the fracture face from 33.7 inches to 36.8 inches (end of visible lack of fusion flaw) from the reference upstream girth weld.

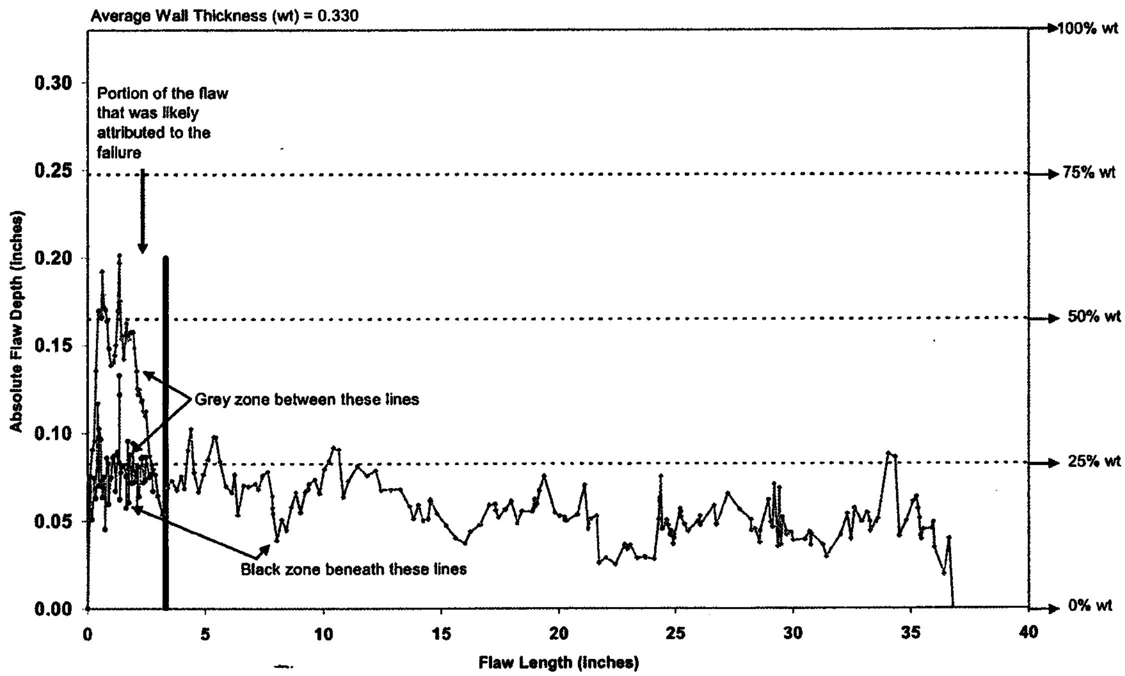


Figure 8. Flaw length versus flaw depth (prior to rupture) of the flaw measured on the fracture surface.

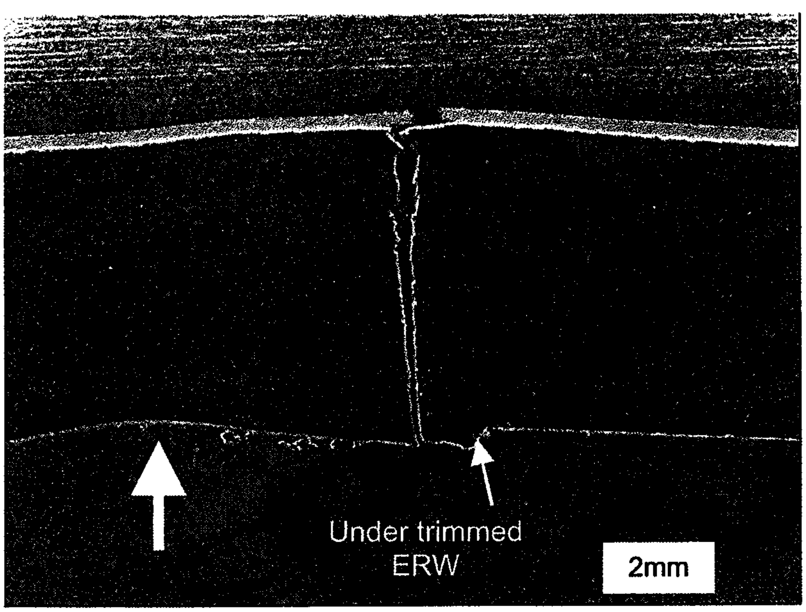


Figure 9. Photograph of a cross section through the rupture 17 inches from the reference upstream girth weld.

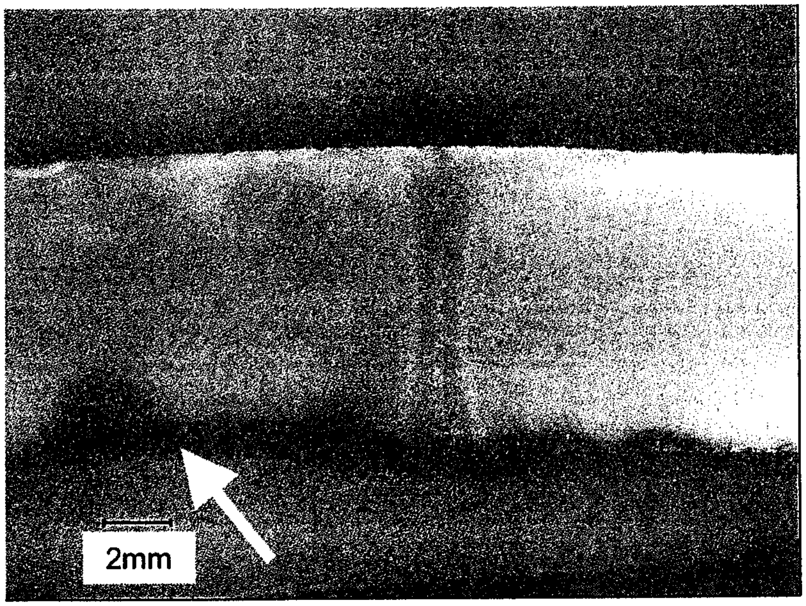


Figure 10. Photograph of the metallographic section through the ERW 59 inches from the reference upstream girth weld. The arrow points to the trimmed area.

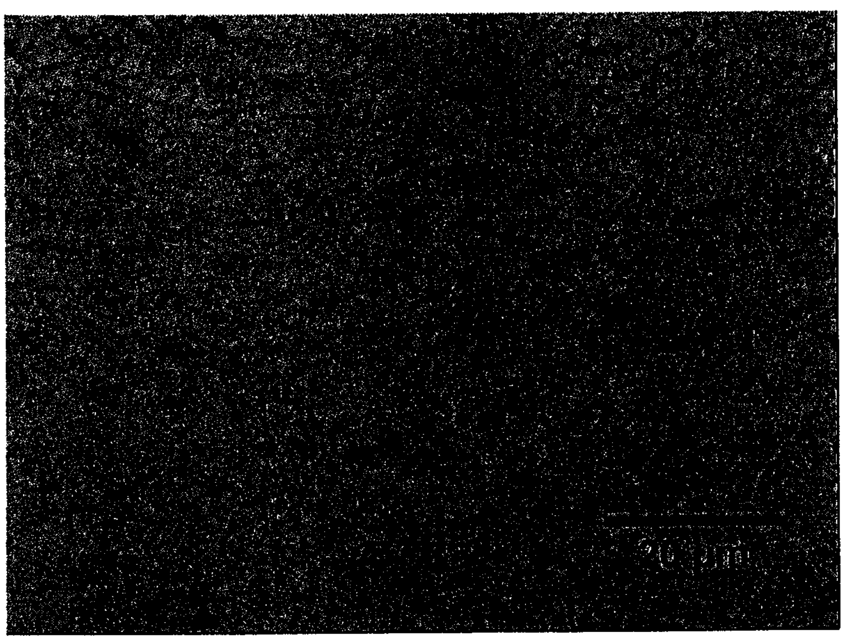


Figure 11. Photomicrograph of the base metal microstructure at 1000X magnification.

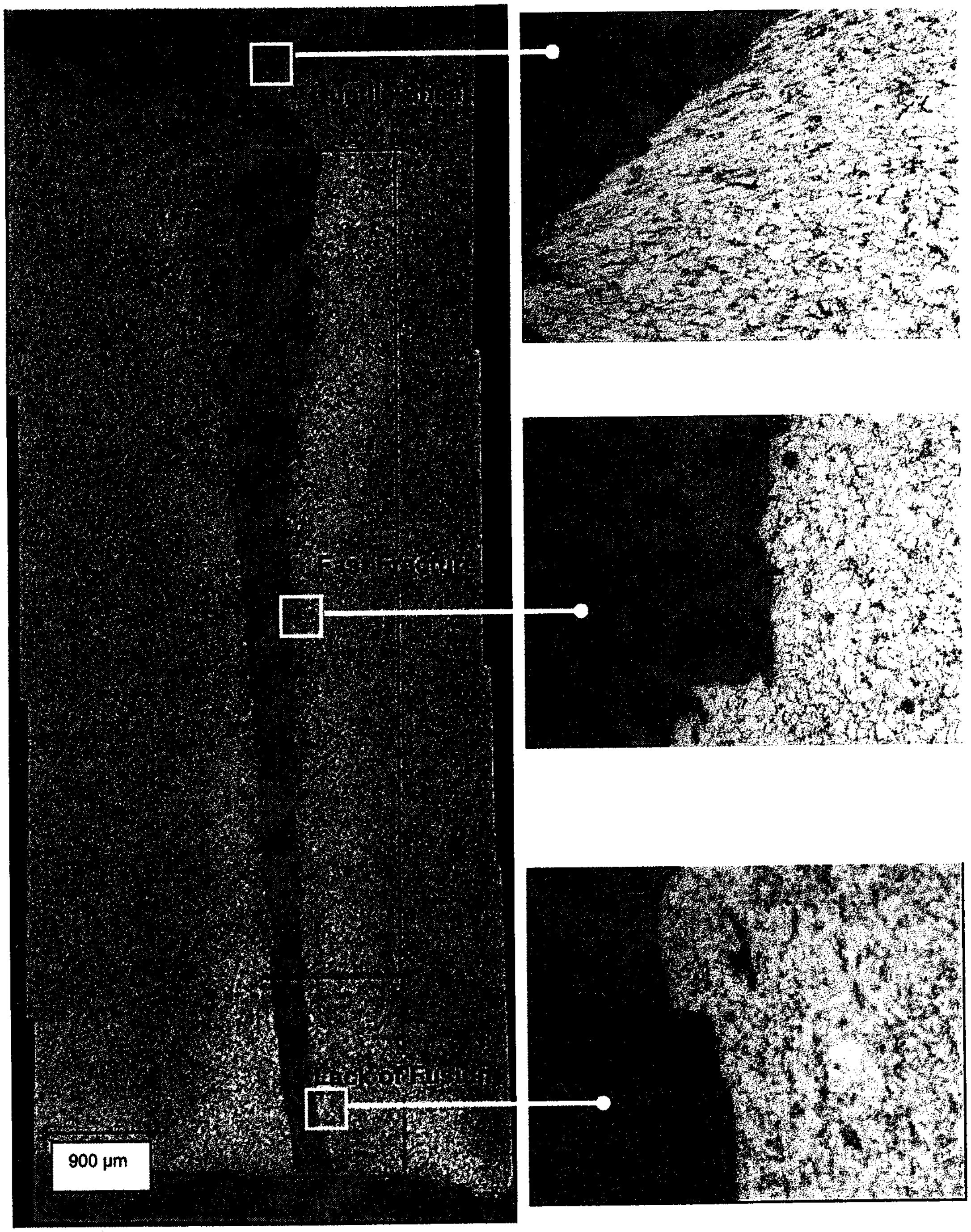


Figure 12. Photomicrograph showing the fracture path in the HAZ 17 inches from the reference upstream girth weld. The lack of fusion, fast fracture, and ductile shear regions are labeled in the figure. 25X magnification.

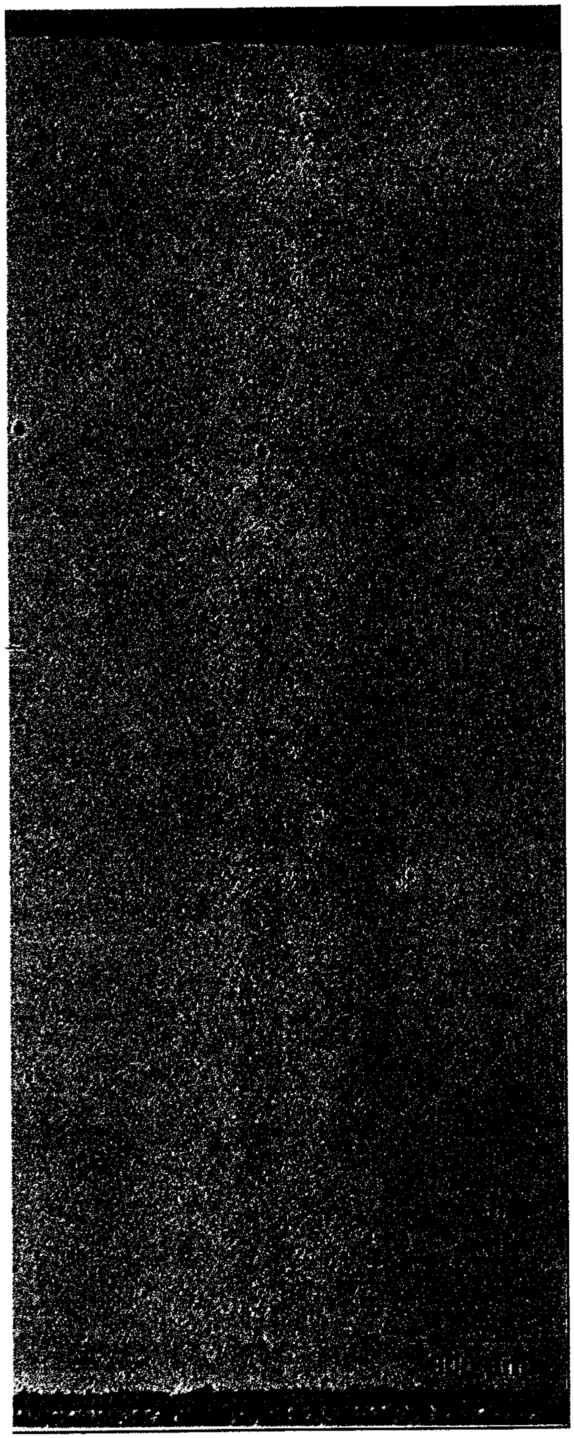


Figure 13. Photomicrograph showing the bond line and HAZ 59 inches from the reference upstream girth weld.

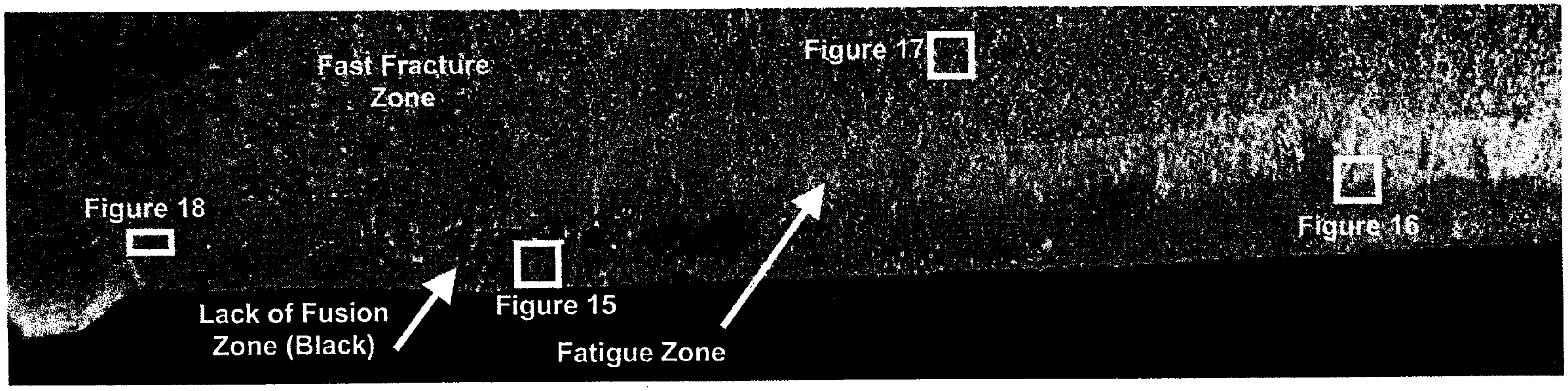


Figure 14. Photograph of fracture face at the failure origin. The lack of fusion zone, fatigue zone, and the fast fracture zone are labeled in the figure. 25X magnification.

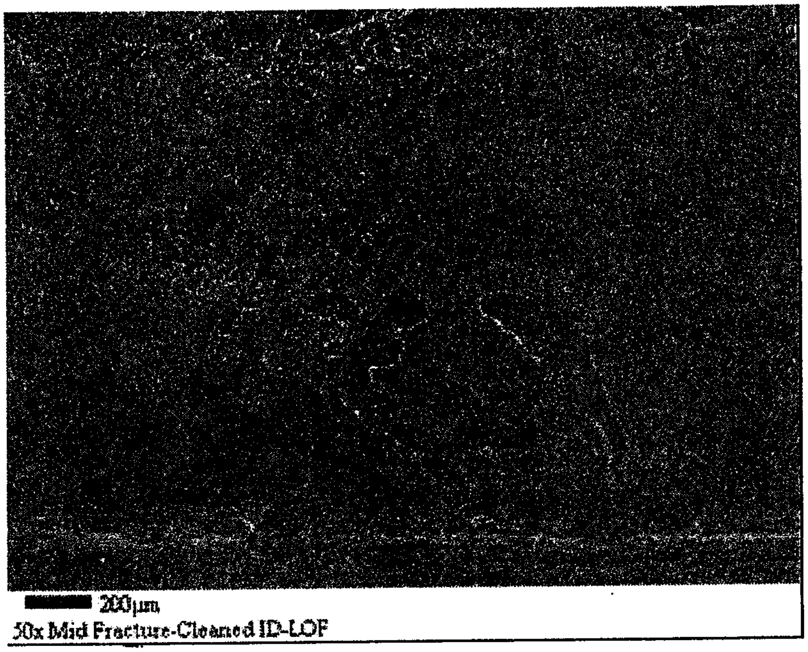


Figure 15. SEM photomicrograph taken in the lack of fusion zone. 50X magnification.

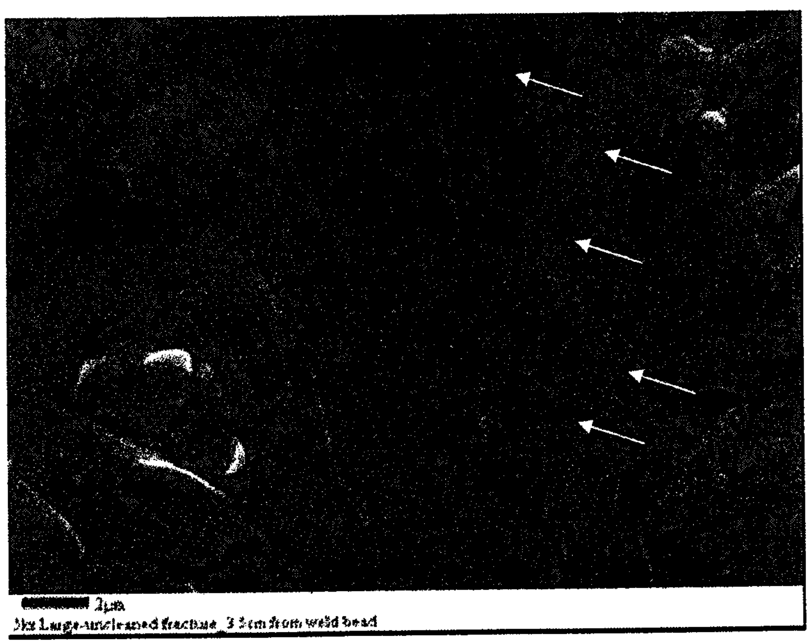


Figure 16. Representative SEM photomicrograph showing fatigue striations in the fatigue zone. 5000X magnification.

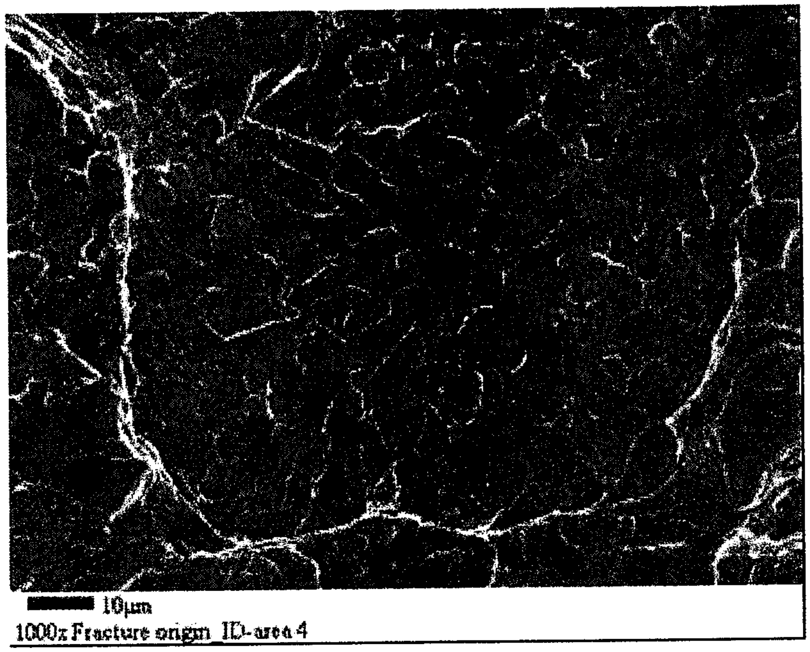


Figure 17. Representative SEM photomicrograph showing cleavage facets in the fast fracture zone. 1000X magnification.

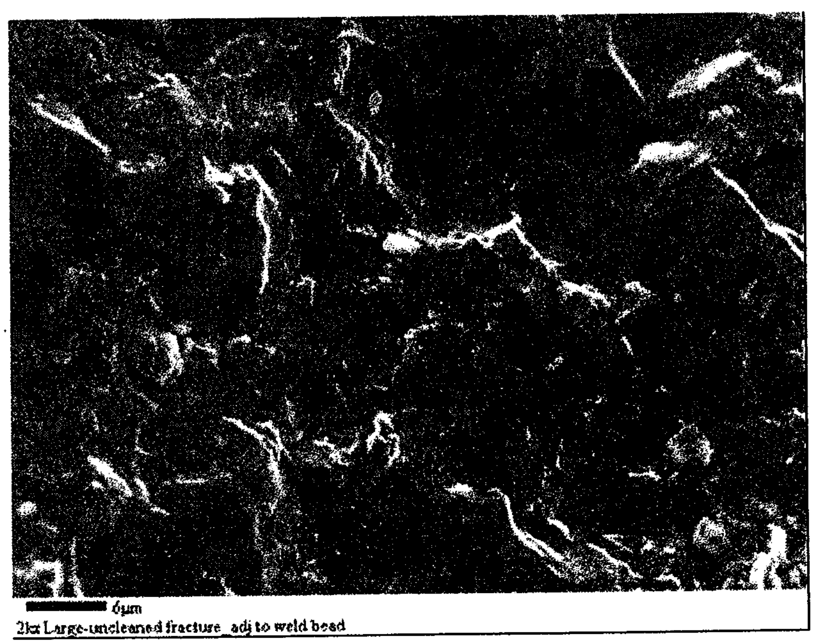


Figure 18. SEM photomicrograph showing intergranular fracture observed adjacent the reference upstream girth weld in the lack of fusion / fatigue zone transition. 2000X magnification.

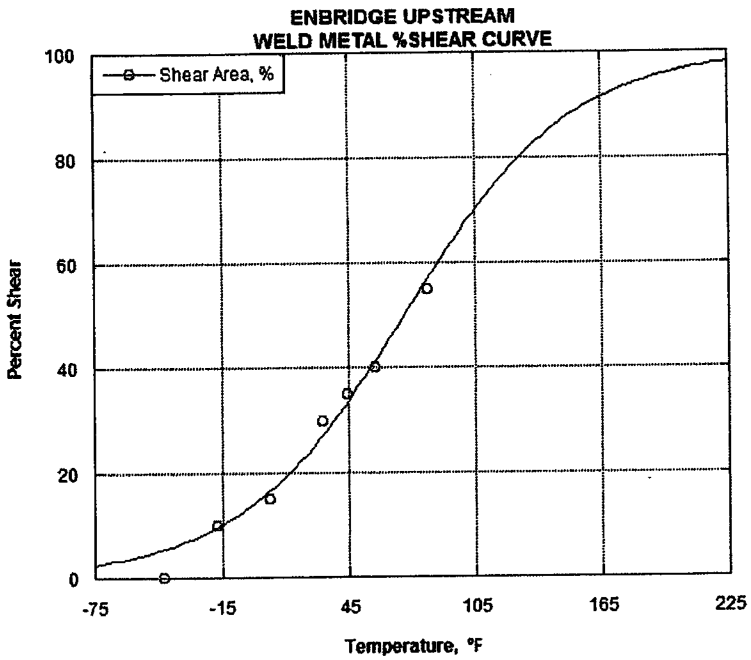


Figure 19. Percent Shear from Charpy V-notch tests as a function of temperature for the upstream joint (weld metal).

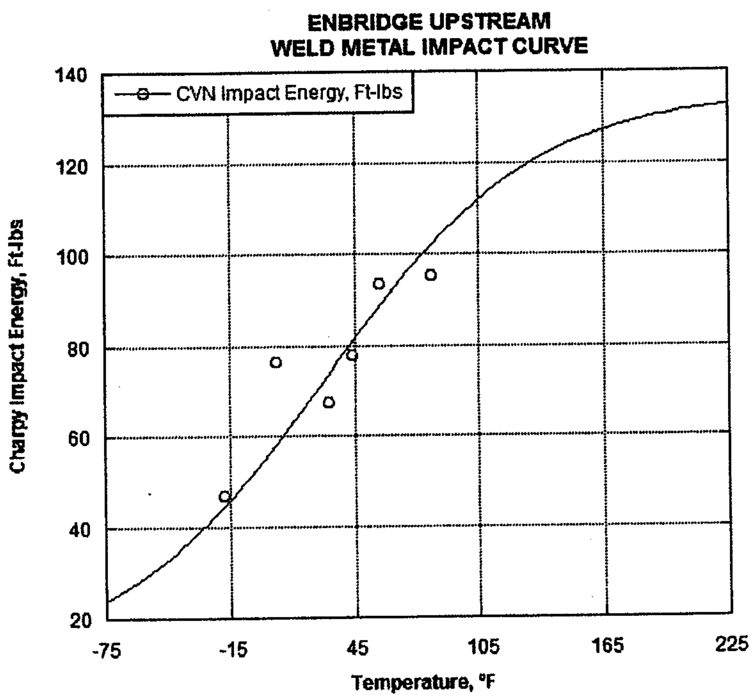


Figure 20. Charpy V-notch impact energy as a function of temperature for the upstream joint (weld metal).

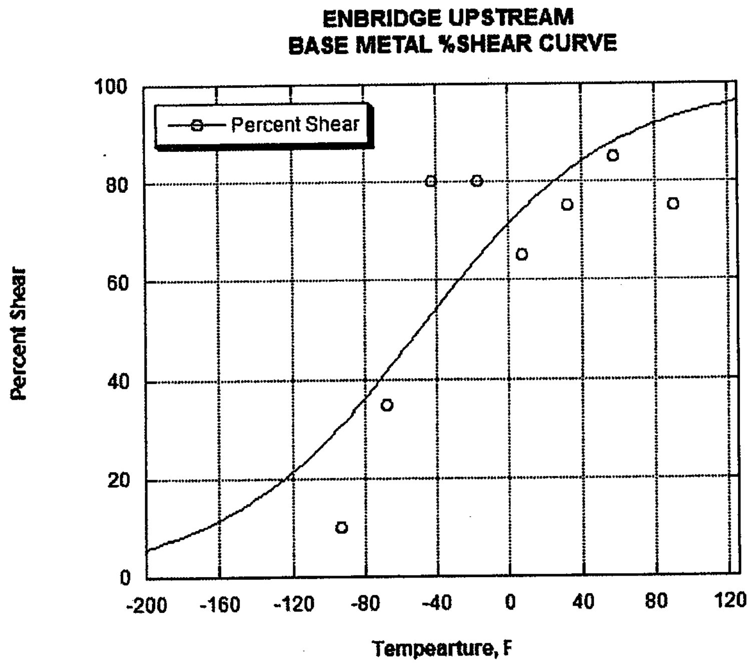


Figure 21. Percent Shear from Charpy V-notch tests as a function of temperature for the upstream joint (base metal).

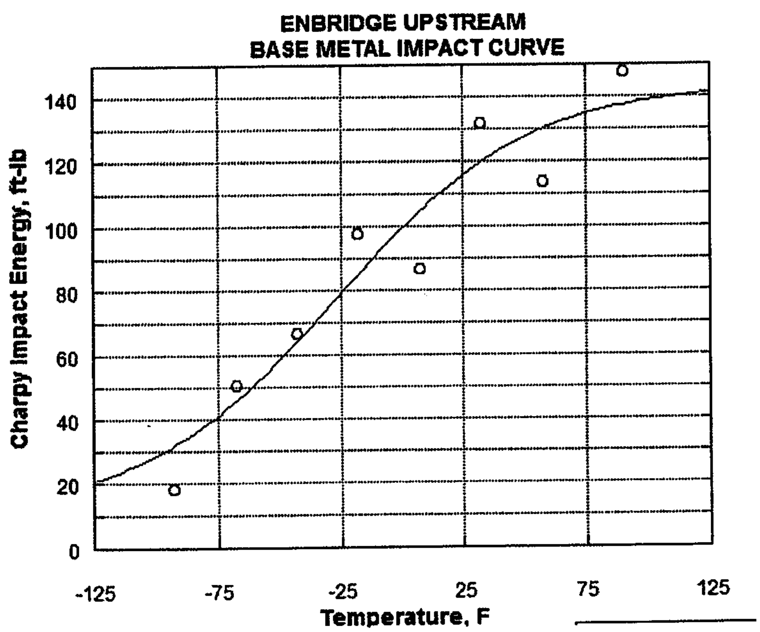


Figure 22. Charpy V-notch impact energy as a function of temperature for the upstream joint (base metal).

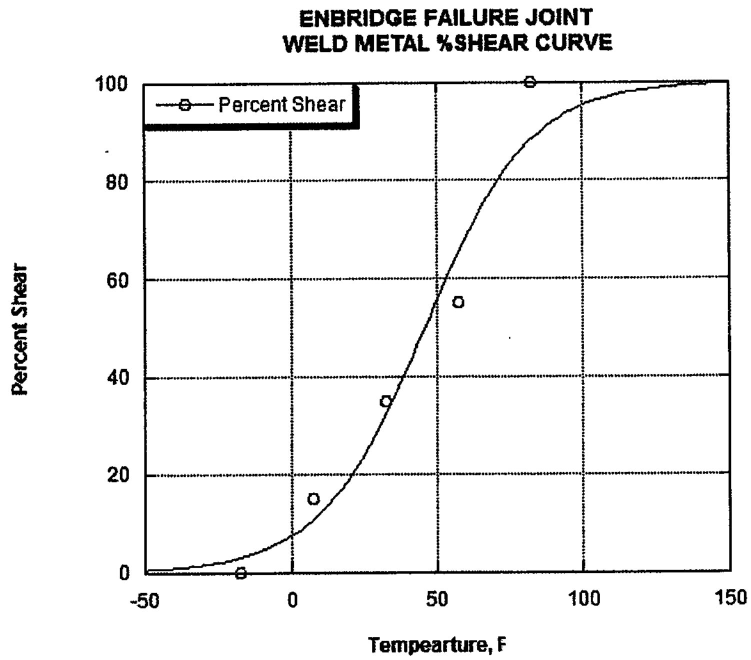


Figure 23. Percent Shear from Charpy V-notch tests as a function of temperature for the failure joint (weld metal).

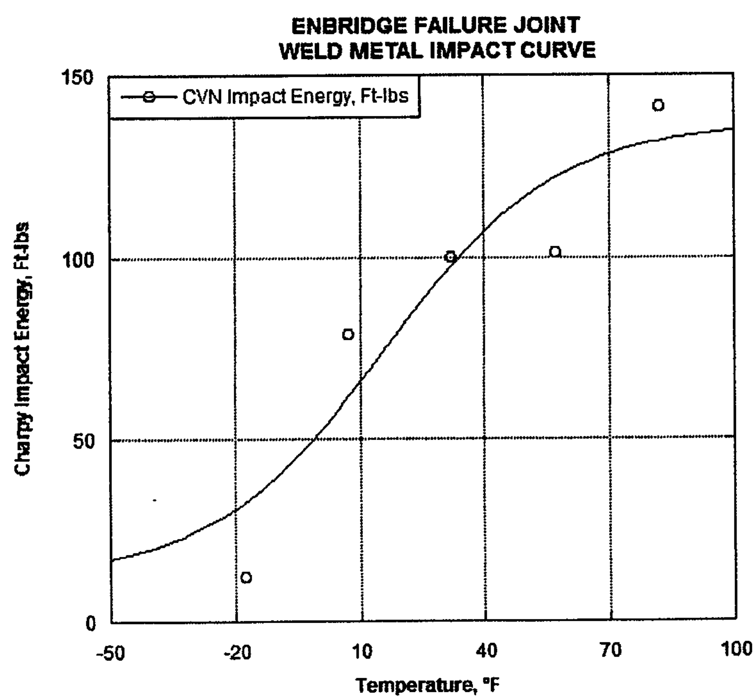


Figure 24. Charpy V-notch impact energy as a function of temperature for the failure joint (weld metal).

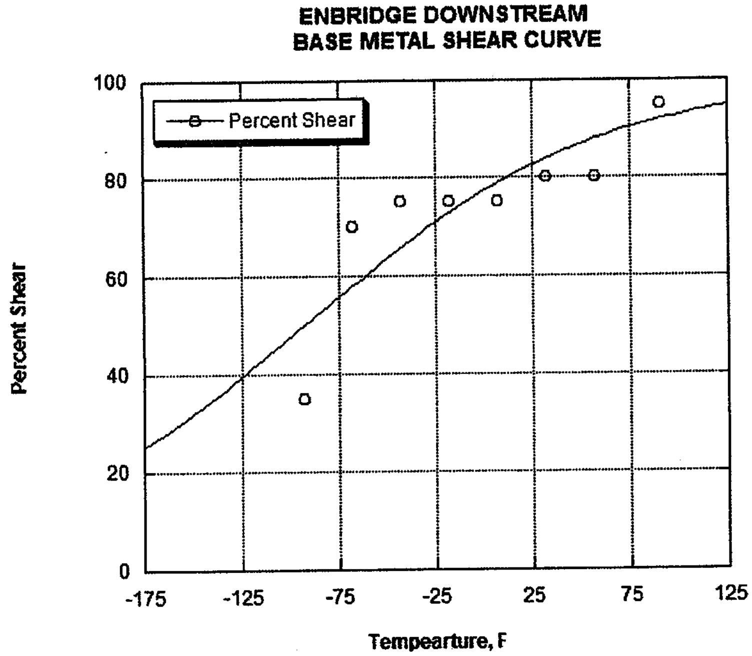


Figure 25. Percent Shear from Charpy V-notch tests as a function of temperature for the failure joint (base metal).

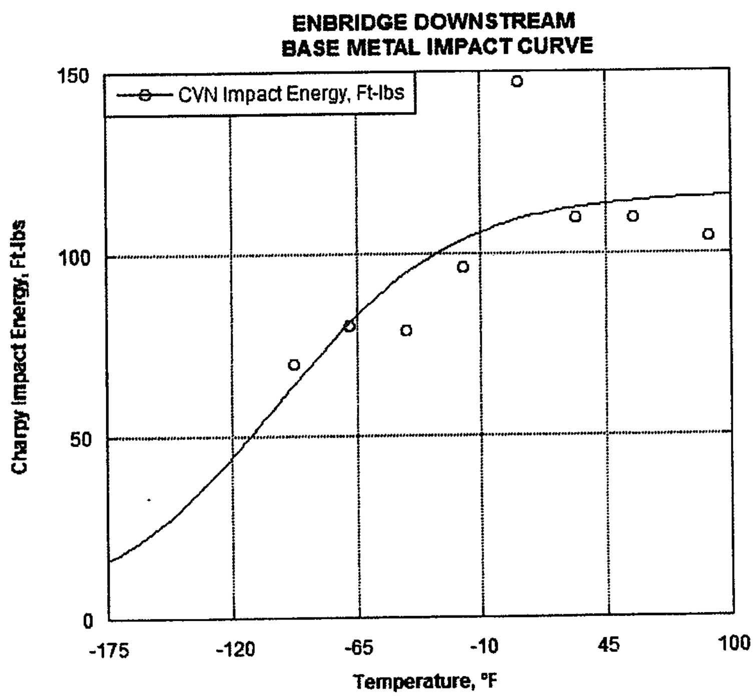


Figure 26. Charpy V-notch impact energy as a function of temperature for the failure joint (base metal).

Leonard

RECEIVED JAN 4 2007

Post Inspection Memorandum (PIM)

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	December 28, 2006	**Inspector:**	Brian Pierzina Brian E. Pierzina
Peer Review/Date:		**Peer Reviewer:**	
Director Approval/Date:		**Director Approval**	

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:**	11169
Name of Unit(s):	Clearbrook to Deer River "OPS Unit #3083"	**Unit #(s):**	3083
Records Location:	119 N. 25th St. East, Superior, WI 54880		
Unit Type & Commodity:	Hazardous Liquid – Crude Oil		
Inspection Type:	Hazardous Liquid – Incident Investigation	**Inspection Date(s):**	10/20,21,26,30/06 12/7,13/06
For OPS :		**AFO Days:**	
For MNOPS :	Brian Pierzina (5 AFO), Boyd Haugrose (1 AFO)	**AFO Days:**	(6)
MNOPS CASE #: 006958			

Summary: Enbridge Energy Company discovered a leak on the 34 inch Line 3 near Pinewood, MN, on October 20, 2006 at M.P. 927.5. The leak was initially reported to Enbridge by a member of the general public who had been on the right-of-way with an ATV, and smelled the odor. All lines in the corridor were initially shut down, until the leak was ultimately confirmed on the 34 inch at approximately 11:05 PM. The leak source was a small defect in the side seam of a tight fitting repair sleeve, at the 3:00 position. There was a series of repair sleeves installed at this location due to a previous leak in 1998, and additional weld seam defects identified through NDT. This leak was coming from the upstream end of the sleeve assembly. Repairs were completed at approximately 12:05 PM, on 10/21/06, and operation of the line was turned back over to the Edmonton Control Center. The estimated volume of the spill is 5 bbls, and the estimated cost is $50,000. The federal Incident Investigation Report form has been completed, and is attached for your reference.

The section of pipe containing the sleeve assembly has been cut out and replaced with new pipe. The pipe has been submitted to CC Technologies for further evaluation, and Gery Bauman, with PHMSA Central Region is planning to oversee these activities. A scope of work for the analysis will be developed by Enbridge's Pipeline Integrity Department, and provided to Gery Bauman.

Enbridge previously experienced three leaks on side seams of repair sleeves that are similar in nature to this leak, back around the year 2000. All of those leaks occurred on repair sleeves that had been tapped out in order to equalize the pressure between the carrier pipe and the repair sleeve. Subsequent analysis indicated the leaks were all due to poor welding of the side seams, most notably inadequate penetration of the root bead. As a result of those findings, Enbridge implemented a program to identify and inspect other tapped out repair sleeves in the system, and repaired most, if not all, of them.

On October 30, 2006, Enbridge had the remainder of the exposed sleeve assembly ultrasonically inspected, and identified additional defects in the side seams of the repair sleeves. This contributed to the ultimate decision to cut the pipe out, and have it analyzed.

The analysis will help determine whether the oil was coming from a new through wall defect in the carrier pipe, or perhaps migrated upstream from the Plidco repair sleeve that had been installed over the first leak. In either case, it seems apparent that the welding of repair sleeves that occurred over a certain timeframe may have been inadequate, and it's likely that many of the sleeves may not be capable of long term service at pipeline pressures.

It's impossible to know which sleeves may be carrying oil at this point. It's also important to note that this potential problem is not limited to the 34 inch pipeline. Repair programs have been implemented previously on all of Enbridge's pipelines, so each of the lines has a certain population of repair sleeves that could have similar types of defects.

Pending the results of the metallurgical evaluation, further actions will likely be necessary. If the analysis reveals inadequate welding and/or welding inspection, MNOPS will prepare a violation report for your consideration. MNOPS would also propose that consideration be given to establishing an inspection program to determine the extent of the problem on each of the pipelines.

Further information should be forthcoming early in 2007. MNOPS does not anticipate any further activities with respect to this case during 2006.

NATIONAL RESPONSE CENTER - FLASH FAX
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
DO NOT RELEASE this information to the public without
permission from the NATIONAL RESPONSE CENTER 1-800-424-8802

Incident Report # 815505

INCIDENT DESCRIPTION

*Report taken by: CIV KEVIN CREWS at 15:49 on 20-OCT-06
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident occurred on 20-OCT-06 at 14:00 local time.
Affected Medium: LAND

REPORTING PARTY

Name: MICHEAL GOLMAN
Organization: ENBRIDGE
Address: 119 NORTH 25TH STREET EAST
SUPERIOR, WI 54880
ENBRIDGE called for the responsible party.
PRIMARY Phone: (715)3941523
Type of Organization: PRIVATE ENTERPRISE

SUSPECTED RESPONSIBLE PARTY

Name: MICHEAL GOLMAN
Organization: ENBRIDGE
Address: 119 NORTH 25TH STREET EAST
SUPERIOR, WI 54880
PRIMARY Phone: (715)3941523
Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

County: BELTRAMI
City: PINEWOOD State: MN
Distance from City:
Direction from City: SE
Section: 12 Township: 147N Range: 35W
SECTION

RELEASED MATERIAL(S)

CHRIS Code: OIL Official Material Name: OIL: CRUDE
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

THE CALLER IS REPORTING A RELEASE OF MATERIALS ONTO THE GROUND FROM A PIPELINE DUE TO UNKNOWN CAUSES AT THIS TIME.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN
INJURIES: NO Hospitalized: Empl/Crew: Passenger:

FATALITIES: NO Empl/Crew: Passenger: Occupant:

EVACUATIONS: NO Who Evacuated: Radius/Area:
Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure	
Air:	N			
Road:	N			Major Artery: N
Waterway:	N			
Track:	N			

Passengers Transferred: NO
Media Interest: NONE Community Impact due to Material: NO

REMEDIAL ACTIONS

EXCAVATED SOIL
Release Secured: UNKNOWN
Release Rate:
Estimated Release Duration:

WEATHER

Weather: PARTLY CLOUDY, 35||F

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: MN DEPT OF PUBLIC SAFTEY
State/Local On Scene: NONE
State Agency Number: 85379

NOTIFICATIONS BY NRC

CG INVESTIGATIVE SVC CHICAGO (CGIS ROA CHICAGO)
20-OCT-06 16:55 (630)9862181
DOT CRISIS MANAGEMENT CENTER (PRIMARY)
20-OCT-06 16:55 (202)3661863
U.S. EPA V (PRIMARY)
(312)3532318
MN DEPT OF HEALTH (PRIMARY)
20-OCT-06 16:55
MN U.S. ATTORNEY'S OFFICE (ATTN: CARL WAHL)
20-OCT-06 16:55 (612)6645742
NATIONAL INFRASTRUCTURE COORD CTR (PRIMARY)
20-OCT-06 16:55 (202)2829201
NOAA RPTS FOR MN (PRIMARY)
20-OCT-06 16:55 (206)5266344
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
20-OCT-06 16:55 (202)3660568
MN DEM ATTN: MS. GOELZ (PRIMARY)
20-OCT-06 16:55 (651)2825391
TSA MARITIME AND LAND (PRIMARY)
20-OCT-06 16:55 (703)5633236

ADDITIONAL INFORMATION

THE CALLER HAD NO ADDITIONAL INFORMATION

*** END INCIDENT REPORT 815505 ***

Pipeline Failure Investigation Report

Pipeline System: Enbridge **Operator:** Enbridge Energy Limited Partnership
Location: Pinewood, M.P. 927.5, Beltrami County **Date of Occurrence:** 10/20/2006
Medium Released: Crude Oil **Quantity:** 5 bbls

PHMSA Arrival Time & Date: 18:25 10/20 MNOPS **Total Damages $** $50,000

Investigation Responsibility: ☒ State ☐ PHMSA ☐ NTSB Other ________

Company Reported Apparent Cause: ☐ Corrosion ☐ Excavation
☐ Natural Forces ☐ Incorrect Operation ☐ Other Outside Force Damage
☒ Material and/or Welds ☐ Equipment and Operations ☐ Other ________

Rupture	☐ Yes	☐ No
Leak	☒ Yes	☐ No
Fire	☐ Yes	☐ No
Explosion	☐ Yes	☐ No
Evacuation	☐ Yes	☐ No

Number of Persons _____ Area _____

Narrative Summary

Short summary of the Incident/Accident which will give interested persons sufficient information to make them aware of the basic scenario and facts.

On October 20, 2006 Enbridge Energy discovered a leak on their 34 inch pipeline near Pinewood, MN, at MP 927.5. An odor was discovered by a member of the general public while riding an ATV on the PL ROW. The Edmonton Control Center was notified, and the leak was confirmed 20 minutes later by Enbridge maintenance personnel. After investigation, it was determined the leak source was the side seam of a full encirclement repair sleeve that had been installed in 1998. The leaking sleeve was initially repaired with an oversleeve, but the entire pipe joint is scheduled for replacement, in order to perform additional analysis.

A prior leak had been discovered at this location in 1998, and was repaired using a Plidco repair sleeve. Additional NDT revealed other defects in the longitudinal seam of the pipe, so the entire pipe joint was sleeved following the initial leak repair. The new leak was coming from the upstream end of the repair configuration, and it hasn't been determined whether the source of the oil was from another failure of the original carrier pipe, or perhaps migrating upstream from the Plidco. Initial ultrasonic testing of the repair sleeve welding indicates additional weld defects, so the affected pipe is scheduled to be cutout and replaced.

There were three previous repair sleeve leaks on this pipeline that occurred around the year 2000. Each of these sleeves were installed in 1998, and had been tapped out in order to equalize the pressure between the sleeve and the carrier pipe. The operator implemented a comprehensive program to investigate and repair similar installations (tapped out repair sleeves). This is the first known leak of a repair sleeve since that time.

Region/State ________ **Reviewed by:** ________
Principal Investigator: ________ **Title:** ________
Date: ________ **Date:** ________

Pipeline Failure Investigation Report

Failure Location & Response		
Location (City, Township, Range, County/Parish): Pinewood, Beltrami County, MN		(Acquire Map)
Address or M.P. on Pipeline: (1) M.P. 927.5	Type of Area (Rural, City): (1) Rural	
Date: 10/20/2006	Time of Failure: Unknown	
Time Detected: 14:20	Time Located: 14:40	
How Located: General public detected odor on the PL ROW while on ATV, and notified Edmonton Control Center		
NRC Report #: (Attach Report) 815505	Time Reported to NRC: 16:49	Reported by: Mike Goman

Type of Pipeline:

Gas Distribution	Gas Transmission	Hazardous Liquid	LNG
☐ LP	☐ Interstate Gas	☒ Interstate Liquid	☐ LNG Facility
☐ Municipal	☐ Intrastate Gas	☐ Intrastate Liquid	
☐ Public Utility	☐ Jurisdictional Gas Gathering	☐ Offshore Liquid	
☐ Master Meter	☐ Offshore Gas	☐ Jurisdictional Liquid Gathering	
	☐ Offshore Gas - High H_2S	☐ CO_2	

Pipeline Configuration (Regulator Station, Pump Station, Pipeline, etc.):
Mainline - 34" in area of previous repair

Operator/Owner Information	
Owner: Enbridge Energy Limited Partnership	Operator: Enbridge Energy Limited Partnership
Address: 1100 Louisiana Ave, Suite 3200, Houston, TX 77002-6216	Address: Same
Company Official: Steve Letwin, Managing Director	Company Official:
Phone No.: 713-650-8900 Fax No.: 713-653-8711	Phone No. Fax No.

Drug and Alcohol Testing Program Contacts ☒ N/A

Drug Program Contact & Phone:
Alcohol Program Contact & Phone:

Damages			
Product/Gas Loss or Spill (2)	5 bbls	Estimated Property Damage $	50,000
Amount Recovered	0	Associated Damages (3) $	0
Estimated Amount $	350		

1 Photo documentation
2 Initial volume lost or spilled
3 Including cleanup cost

Pipeline Failure Investigation Report

Damages

Description of Property Damage:
Contaminated soil removal and PL repair

Customers out of Service:	☐ Yes	☒ No	Number: ____
Suppliers out of Service:	☐ Yes	☒ No	Number: ____

Fatalities and Injuries

Fatalities:	☐ Yes	☒ No	Company: ____	Contractor: ____	Public: ____
Injuries - Hospitalization:	☐ Yes	☒ No	Company: ____	Contractor: ____	Public: ____
Injuries - Non-Hospitalization:	☐ Yes	☒ No	Company: ____	Contractor: ____	Public: ____
Total Injuries (including Non-Hospitalization):			Company: ____	Contractor: ____	Public: ____

Name	Job Function	Yrs w/ Comp.	Yrs. Exp.	Type of Injury

Drug/Alcohol Testing ☒ N/A

Were all employees that could have contributed to the incident, post-accident tested within the 2 hour time frame for alcohol or the 32 hour time frame for all other drugs?

☐ Yes ☐ No

Job Function	Test Date & Time	Location	Results		Type of Drug
			Pos	Neg	
			☐	☐	
			☐	☐	
			☐	☐	
			☐	☐	
			☐	☐	

Pipeline Failure Investigation Report

System Description
Describe the Operator's System: The operator transports crude oil and HVLs from Western Canada to Midwest and Eastern markets through a parallel system of interstate pipelines. In this area specifically, there are 18, 26, 34, and 36 inch pipelines. The upstream pumping station is located at the Clearbrook Terminal, and the downstream pumping station is located at Cass Lake.

Pipe Failure Description	☐ N/A
Length of Failure (inches, feet, miles): pinhole leak in side seam of repair sleeve (1)	
Position (Top, Bottom, include position on pipe, 6 O'clock): (1) 3:00	Description of Failure (Corrosion Gouge, Seam Split): (1) Pinhole leak in side seam of repair sleeve
Laboratory Analysis: ☒ Yes ☐ No Performed by: CC Technologies (scheduled)	
Preservation of Failed Section or Component: ☒ Yes ☐ No If Yes - Method: Cutout portion will have ends sealed. Failed sleeve was encapsulated.	
In Custody of: Operator	
Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Direction of Flow.	

Component Failure Description	☒ N/A
Component Failed: (1)	
Manufacturer:	Model:
Pressure Rating:	Size:
Other (Breakout Tank, Underground Storage):	

Pipe Data	☐ N/A
Material: Steel	Wall Thickness/SDR: .281
Diameter (O.D.): 34"	Installation Date: 19
SMYS: 52,000	Manufacturer: U.S. Steel
Longitudinal Seam: SAW	Type of Coating: Polyken Tape
Pipe Specifications (API 5L, ASTM A53, etc.): API 5L	

Joining	☐ N/A
Type: SMAW	Procedure: LB32
NDT Method: Mag Particle	Inspected: ☒ Yes ☐ No

Pipeline Failure Investigation Report

Pressure @ Time of Failure @ Failure Site ☒ N/A				
Pressure @ Failure Site: 220 psig		Elevation @ Failure Site: 1400 ft		
Pressure Readings @ Various Locations:			Direction from Failure Site	
Location/M.P./Station #	Pressure (psig)	Elevation (ft msl)	Upstream	Downstream

Upstream Pump Station Data ☒ N/A	
Type of Product:	API Gravity:
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure [(4)]	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Upstream Compressor Station Data ☒ N/A	
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure [(4)]	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Operating Pressure ☐ N/A	
Max. Allowable Operating Pressure: 618 psig	Determination of MAOP: hydrotest
Actual Operating Pressure: 220 psig @ leak site @ tof	
Method of Over Pressure Protection: SCADA	
Relief Valve Set Point:	Capacity Adequate? ☐ Yes ☐ No

Integrity Test After Failure ☒ N/A
Pressure Test Conducted in place? (Conducted on Failed Components or Associated Piping): ☐ Yes ☐ No
If NO, Tested after removal? ☐ Yes ☐ No
Method:
Describe any failures during the test.

Soil/water Conditions @ Failure Site ☐ N/A
Condition of and Type of Soil around Failure Site (Color, Wet, Dry, Frost Depth): **Sandy**
Type of Backfill (Size and Description): **Sand**

4 Obtain event logs and pressure recording charts

Pipeline Failure Investigation Report

Soil/water Conditions @ Failure Site	☐ N/A
Type of Water (Salt, Brackish):	Water Analysis (5) ☐ Yes ☐ No

External Pipe or Component Examination	☐ N/A
External Corrosion? ☐ Yes ☒ No (1)	Coating Condition (Disbonded, Non-existent): (1) Good
Description of Corrosion:	
Description of Failure Surface (Gouges, Arc Burns, Wrinkle Bends, Cracks, Stress Cracks, Chevrons, Fracture Mode, Point of Origin):	
Above Ground: ☐ Yes ☒ No (1)	Buried: ☒ Yes ☐ No (1)
Stress Inducing Factors: No (1)	Depth of Cover: 40 inches (1)

Cathodic Protection	☒ N/A
P/S (Surface):	P/S (Interface):
Soil Resistivity: pH:	Date of Installation:
Method of Protection:	
Did the Operator have knowledge of Corrosion before the Incident? ☐ Yes ☐ No	
How Discovered? (Close Interval Survey, Instrumented Pig, Annual Survey, Rectifier Readings, ECDA, etc):	

Internal Pipe or Component Examination	☒ N/A
Internal Corrosion: ☐ Yes ☐ No (1)	Injected Inhibitors: ☐ Yes ☐ No
Type of Inhibitors:	Testing: ☐ Yes ☐ No
Results (Coupon Test, Corrosion Resistance Probe):	
Description of Failure Surface (MIC, Pitting, Wall Thinning, Chevrons, Fracture Mode, Point of Origin):	
Cleaning Pig Program: ☐ Yes ☐ No	Gas and/or Liquid Analysis: ☐ Yes ☐ No

5 Attach copy of water analysis report

Pipeline Failure Investigation Report

Internal Pipe or Component Examination ☒ N/A	
Results of Gas and/or Liquid Analysis [6]	
Internal Inspection Survey: ☐ Yes ☐ No	Results [7]
Did the Operator have knowledge of Corrosion before the Incident? ☐ Yes ☐ No	
How Discovered? (Instrumented Pig, Coupon Testing, ICDA, etc.):	

Outside Force Damage ☒ N/A	
Responsible Party:	Telephone No.:
Address:	
Work Being Performed:	
Equipment Involved: [1]	Called One Call System? ☐ Yes ☐ No
One Call Name:	One Call Report # [8]
Notice Date:	Time:
Response Date:	Time:
Details of Response:	
Was Location Marked According to Procedures? ☐ Yes ☐ No	
Pipeline Marking Type: [1]	Location: [1]
State Law Damage Prevention Program Followed? ☐ Yes ☐ No ☐ No State Law	
Notice Required: ☐ Yes ☐ No	Response Required: ☐ Yes ☐ No
Was Operator Member of State One Call? ☐ Yes ☐ No	Was Operator on Site? ☐ Yes ☐ No
Did a deficiency in the Public Awareness Program contribute to the accident? ☐ Yes ☐ No	
Is OSHA Notification Required? ☐ Yes ☐ No	

Natural Forces ☒ N/A
Description (Earthquake, Tornado, Flooding, Erosion):

6 Attach copy of gas and/or liquid analysis report
7 Attach copy of internal inspection survey report
8 Attach copy of one-call report

Pipeline Failure Investigation Report

Failure Isolation	☐ N/A
Squeeze Off/Stopple Location and Method: (1) **Isolated using upstream and downstream valves**	
Valve Closed - Upstream: Clearbrook Time: w/in 3 minutes	I.D.: M.P.: 909.43
Valve Closed - Downstream: Cass Lake Time: w/in 3 minutes	I.D.: M.P.: 953.02
Pipeline Shutdown Method: ☒ Manual ☐ Automatic ☐ SCADA ☒ Controller ☐ ESD	
Failed Section Bypassed or Isolated: Isolated	
Performed By: Control Center and Maintenance Personnel	Valve Spacing: 89,319 ft

Odorization	☒ N/A
Gas Odorized: ☐ Yes ☐ No	Concentration of Odorant (Post Incident at Failure Site):
Method of Determination: ☐ Yes ☐ No	% LEL: ☐ Yes ☐ No % Gas In Air: ☐ Yes ☐ No Time Taken: ☐ Yes ☐ No
Was Odorizer Working Prior to the Incident? ☐ Yes ☐ No	Type of Odorizer (Wick, By-Pass):
Odorant Manufacturer: Model:	Type of Odorant:
Amount Injected:	Monitoring Interval (Weekly):
Odorization History (Leaks Complaints, Low Odorant Levels, Monitoring Locations, Distances from Failure Site):	

Weather Conditions	☒ N/A
Temperature:	Wind (Direction & Speed):
Climate (Snow, Rain):	Humidity:
Was Incident preceded by a rapid weather change? ☐ Yes ☐ No	
Weather Conditions Prior to Incident (Cloud Cover, Ceiling Heights, Snow, Rain, Fog):	

Gas Migration Survey	☒ N/A
Bar Hole Test of Area: ☐ Yes ☐ No	Equipment Used:
Method of Survey (Foundations, Curbs, Manholes, Driveways, Mains, Services) [9] (1)	

9 Plot on site description page

Pipeline Failure Investigation Report

Environment Sensitivity Impact	☐ N/A
Location (Nearest Rivers, Body of Water, Marshlands, Wildlife Refuge, City Water Supplies that could be or were affected by the medium loss): (1) **Environmental Impact Assessment was conducted by the operator. Contaminated soil was removed. No further actions anticipated**	
OPA Contingency Plan Available? ☒ Yes ☐ No	Followed? ☒ Yes ☐ No

Class Location/High Consequence Area	☒ N/A
Class Location: 1 ☐ 2 ☐ 3 ☐ 4 ☐ Determination: _____	HCA Area? ☐ Yes ☐ No ☐ N/A Determination: _____
Odorization Required? ☐ Yes ☐ No ☐ N/A	

Pressure Test History ☒ N/A
(Expand List as Necessary)

	Req'd (10) Assessment Deadline Date	Test Date	Test Medium	Pressure (psig)	Duration (hrs)	% SMYS
Installation	N/A					
Next						
Next						
Most Recent						

Describe any problems experienced during the pressure tests.

Internal Line Inspection/Other Assessment History ☒ N/A
(Expand List as Necessary)

	Req'd (10) Assessment Deadline Date	Assessment Date	Type of ILI Tool (11)	Other Assessment Method (12)	Indicated Anomaly If yes, describe below
Initial					☐ Yes ☐ No
Next					☐ Yes ☐ No
Next					☐ Yes ☐ No
Most Recent					☐ Yes ☐ No

Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions.

10 As required of Pipeline Integrity Management regulations in 49CFR Parts 192 and 195
11 MFL, geometry, crack, etc.
12 ECDA, ICDA, SCCDA, "other technology," etc.

Pipeline Failure Investigation Report

Pre-Failure Conditions and Actions	☐ N/A
Was there a known pre-failure condition requiring [10] the operator to schedule evaluation and remediation? ☐ Yes (describe below or on attachment) ☒ No	
If there was such a known pre-failure condition, had the operator established and adhered to a required [10] evaluation and remediation schedule? Describe below or on attachment. ☐ Yes ☐ No ☒ N/A	
Prior to the failure, had the operator performed the required [10] actions to address the threats that are now known to be related to the cause of this failure? ☐ Yes ☐ No ☒ N/A List below or on an attachment such operator-identified threats, and operator actions taken prior to the accident.	
Describe any previously indicated anomalies at the failed pipe, and any subsequent pipe inspections (anomaly digs) and remedial actions. **Pipe joint had previously been inspected for long seam defects, and had previously leaked (1998), so the entire joint had been sleeved in 1998. Failure occurred in the repair sleeve.**	

Maps & Records	☐ N/A
Are Maps and Records Current? [13] ☒ Yes ☐ No Comments:	

Leak Survey History	☒ N/A
Leak Survey History (Trend Analysis, Leak Plots):	

Pipeline Operation History	☐ N/A
Description (Repair or Leak Reports, Exposed Pipe Reports): **Pipeline has been subject of numerous integrity related inspections and repairs, and has experienced a number of prior leaks/ruptures. There have been three previous leaks of side seam repair sleeves that were installed during this same time period.**	
Did a Safety Related Condition Exist Prior to Failure? ☐ Yes ☒ No Reported? ☐ Yes ☐ No	
Unaccounted For Gas:	
Over & Short/Line Balance (24 hr., Weekly, Monthly/Trend):	

Operator/Contractor Error	☒ N/A
Name:	Job Function:
Title:	Years of Experience:
Training (Type of Training, Background):	
Was the person "Operator Qualified" as applicable to a precursor abnormal operating condition? ☐ Yes ☐ No ☐ N/A	
Was qualified individual suspended from performing covered task ☐ Yes ☐ No ☐ N/A	
Type of Error (Inadvertent Operation of a Valve):	

13 Obtain copies of maps and records

Pipeline Failure Investigation Report

Operator/Contractor Error ☒ N/A
Procedures that are required:
Actions that were taken:
Pre-Job Meeting (Construction, Maintenance, Blow Down, Purging, Isolation):
Prevention of Accidental Ignition (Tag & Lock Out, Hot Weld Permit):
Procedures conducted for Accidental Ignition:
Was a Company Inspector on the Job? ☐ Yes ☐ No
Was an Inspection conducted on this portion of the job? ☐ Yes ☐ No
Additional Actions (Contributing factors may include number of hours at work prior to failure or time of day work being conducted):
Training Procedures:
Operation Procedures:
Controller Activities:

Name	Title	Years Experience	Hours on Duty Prior to Failure	Shift

Alarm Parameters:
High/Low Pressure Shutdown:
Flow Rate:
Procedures for Clearing Alarms:
Type of Alarm:
Company Response Procedures for Abnormal Operations:
Over/Short Line Balance Procedures:
Frequency of Over/Short Line Balance:
Additional Actions:

Pipeline Failure Investigation Report

Additional Actions Taken by the Operator ☐ N/A

Make notes regarding the emergency and Failure Investigation Procedures (Pressure reduction, Reinforced Squeeze Off, Clean Up, Use of Evacuators, Line Purging, closing Additional Valves, Double Block and Bleed, Continue Operating downstream Pumps):

The operator has scheduled the affected pipe for cutout in December of 2006, in order to determine additional circumstances associated with the failure. The configuration was such that a Plidco repair sleeve had been installed over a leaking seam defect, with additional sleeving installed upstream and downstream. It appears evident that the leak in the side seam of the repair sleeve was due to a poor weld, but it's unclear whether the oil migrated upstream from the Plidco, or another defect had subsequently failed through the original carrier pipe. Metallurgical analysis will provide answers to these questions as well as providing an opportunity to further evaluate the repair sleeve welding.

Photo Documentation

Overall Area from best possible view. Pictures from the four points of the compass. Failed Component, Operator Action, Damages in Area, Address Markings, etc.

Photo No.	Description	Roll No.	Photo No.	Description	Roll No.
1	CD containing digital images included		1		
2			2		
3			3		
4			4		
5			5		
6			6		
7			7		
8			8		
9			9		
10			10		
11			11		
12			12		
13			13		
14			14		
15			15		
16			16		
17			17		
18			18		
19			19		
20			20		

Type of Camera:

Film ASA:

Video Counter Log (Attach Copy):

Pipeline Failure Investigation Report

Additional Information Sources			
Agency	Name	Title	Phone Number
Police:			
Fire Dept.:			
State Fire Marshall:			
State Agency:			
NTSB:			
EPA:			
FBI:			
ATF:			
OSHA:			
Insurance Co.:			
FRA:			
MMS:			
Television:			
Newspaper:			
Other:			

Persons Interviewed		
Name	Title	Phone Number

Pipeline Failure Investigation Report

Event Log	
Sequence of events prior, during, and after the incident by time. (Consider the events of all parties involved in the incident, Fire Department and Police reports, Operator Logs and other government agencies.)	
Time	Event

Pipeline Failure Investigation Report

Investigation Contact Log			
Time	Date	Name	Description

Pipeline Failure Investigation Report

Failure Investigation Documentation Log				
Operator:	Unit #:	CPF #:	Date:	
Appendix Number	Documentation Description	Date Received	FOIA	
			Yes	No

Site Description
Provide a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Photos should be taken from all angles with each photo documented. Additional areas may be needed in any area of this guideline.

MINNESOTA DEPARTMENT OF PUBLIC SAFETY

Office of Pipeline Safety
444 Cedar Street, Suite 147, St. Paul, Minnesota 55101-5147
Phone: 651/296-9636 FAX: 651.296.9641 TTY: 651/282-5555
Internet: http://www.dps.state.mn.us

Alcohol & Gambling Enforcement
Bureau of Criminal Apprehension
Capitol Security
Driver & Vehicle Services
Emergency Management/ Emergency Response Commission
State Fire Marshal/ Pipeline Safety
State Patrol
Traffic Safety

March 15, 2004

Case No. 004634-1

Mr. Ivan Huntoon, Central Region Director
Federal Office of Pipeline Safety
901 Locust Street, Room 462
Kansas City, MO 64106

INTERSTATE AGENT INSPECTION REPORT
Pipeline Failure - Outside Force - Enbridge Energy Company, Inc.

Dear Mr. Huntoon:

The Minnesota Office of Pipeline Safety (MNOPS) submits the following report as per its Interstate Agent Agreement with the Office of Pipeline Safety:

SYNOPSIS: On February 19, 2004, Enbridge Energy discovered a leak on the 26 inch Line 2 while conducting a maintenance excavation for an internal inspection indication at M.P. 1007.33, in Grand Rapids, MN. Further investigation revealed the leak was due to a crack within a dent, on the bottom of the pipe. The leak was repaired with a tight fitting sleeve, and the line was back in service by 10:30 PM.

KEY INFORMATION:

Inspection Unit:	OPID 11169, 152 CE System 1, Unit 3803; MNOPS Unit 153161
Company HQ:	Enbridge Energy Company, Inc. 1100 Louisiana, Suite 2950 Houston, TX 77002-7002
MNOPS Inspector:	Brian Pierzina
OPS Inspector:	None
AFO Days:	1
Inspection Date:	February 19, 2004
Persons Interviewed:	Mark Willoughby –Manager, Compliance & Risk Management Jay Johnson – Compliance Coordinator Patsy Bolk – Compliance Secretary

INSPECTION OVERVIEW:

Enbridge reported a suspected leak to Minnesota's Division of Homeland Security and Emergency Management (HSEM) at 12:52 PM on February 19, 2004. Oily soil was discovered while a maintenance crew was excavating the 26 inch Line 2, at M.P. 1007.33, on the northwest side of Grand Rapids. The excavation was being conducted to assess an internal inspection indication for a possible dent with metal loss. As the crew was excavating they found contaminated soil, and as they got closer to the pipe, it became fresher. The line was shut down at approximately 11:30 AM, while the crew continued excavating. At approximately 4:00 PM, the leak was confirmed to be from a crack, within a dent, on the bottom side of the pipe. The crack was approximately 2 inches long on the OD of the pipe, and was oriented approximately 5 degrees off of the circumferential plane. With the pipeline holding approximately 200 psig, it took almost 20 minutes for a drop of oil to escape. The pipeline was repaired with a 12 inch tight fitting repair sleeve, and the line was back in service at approximately 10:30 PM. The environment was relatively rocky, with both large and small rocks throughout the area.

Enbridge has provided the following information related to the internal inspections that were conducted:

ILI tool run dates:	GE-Positive Projects - CaliPPer September 3, 2003 GE-PII MFL - September 10-12, 2003
ILI report due dates:	GE-Positive Projects - October 31, 2003 GE-PII MFL - December 10, 2003
ILI report received date:	GE-Positive Projects - December 1, 2003 GE-PII MFL - December 1, 2003
ILI report accepted date:	GE-Positive Projects - December 18, 2003 GE-PII MFL - December 18, 2003

180-day report acceptance due date: March 10, 2004

Dig package issue date: January 19, 2004

MNOPS has discussed with Enbridge the need to evaluate the reported defect, and determine whether similar anomalies may exist along the pipeline. This would be handled by their Pipeline Integrity Department. We recommend that a formal request for information be issued to Enbridge in order to obtain details of this reported anomaly, as well as others that were issued as part of the dig package. This information should include field findings, and whether any repairs were performed.

Any additional anomalies that are identified as part of this further review should also be included. We believe the written request for information will ensure appropriate information is provided to all parties in a timely and consistent manner.

A violation report is included with this report as a result of the operator not telephonically reporting this incident to the NRC until March 2, 2004. The initial spill estimate was one barrel, but was subsequently revised upward, based on the amount of soil that was removed from the area. There was no initial estimate

associated with the cost of the spill, although it was apparent the following week that the cost would exceed $50,000.
At that point, however, it is not likely that the telephonic reporting requirements were being considered, as the leak had been repaired, the contaminated soil had been removed, and the entire spill response process was near completion.

Prepared by,

Brian Pierzina, Senior Engineer

For the Minnesota Office of Pipeline Safety,

Charles R. Kenow, Administrator

cc: Leonard Steiner, OPS

UNITED STATES DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
OFFICE OF PIPELINE SAFETY
HAZARDOUS LIQUID PIPELINE SAFETY VIOLATION REPORT

1. Inspector Name	Brian Pierzina	
2. Date of Inspection	02/19/04	1 AFO Day
3.CPF#		
~~**4.Pipeline Operator/Owner**~~	~~Enbridge Energy Company~~	
5a.Headquarters Address	Enbridge Energy Company, Inc. 1100 Louisiana Avenue Suite 2950 Houston, TX 77002-7002	
5b.Telephone No.	(713) 650-8300	
6.Inspection Location	M.P. 1007.33 (NW side of Grand Rapids, MN)	
7.Inspection Unit	OPID 11169, 152 CE System 1, OPS Unit 3803 MNOPS Unit 153161	

8.Portion of System Inspected (Describe location & facility)
Enbridge reported a suspected leak to Minnesota's Division of Homeland Security and

Emergency Management (HSEM) at 12:52 PM, on 2/19/04. Oily soil was discovered while a maintenance crew was excavating the 26 inch Line 2, at M.P. 1007.33, on the NW side of Grand Rapids. The excavation was being conducted to assess an internal inspection indication for a possible dent with metal loss. As the crew was excavating they found contaminated soil, and as they got closer to the pipe, it became fresher. The line was shut down at approximately 11:30 AM, while the crew continued excavating. At approximately 4:00 PM, the leak was confirmed to be from a crack, within a dent, on the bottom side of the pipe. The crack was approximately 2 inches long on the OD of the pipe, and was oriented approximately 5 degrees off of the circumferential plane. With the pipeline holding approximately 200 psig, it took almost 20 minutes for a drop of oil to escape. The pipeline was repaired with a 12 inch tight fitting repair sleeve, and the line was back in service at approximately 10:30 PM. The environment was relatively rocky, with both large and small rocks throughout the area.

9. Nature and Size of System

Number of Miles - 325 miles North Dakota Border to Wisconsin Border

Commodities Transported - Crude Oil

Relevant Details with Respect to System

10. Nature of Probable Violations (Check as many as applicable)

__1. Problem in Design/Materials
__2. Problem in Construction
_X_3. Reporting Requirements
__4. Test Requirements
__5. Personnel Qualifications and Training
__6. Anti-drug Program (less than 50 employees)
__7. Other Operations
__8. Corrosion Control
__9. Pressure Control
__10. Other Maintenance/Monitoring
__11. Inadequate Procedures
  __A. Construction
  __B. ~~Corrosion Control~~
  __C. Operations
  __D. Training
  __E. Maintenance

Violation No. 1

11a. CFR § Violated: 195.52(a)

11b. Summarize what the regulation requires that operator did not do:
The regulation requires the operator to provide telephonic notice to the National Response Center at the earliest practicable moment following discovery of a release of hazardous liquid meeting certain criteria. In this case, estimated property damage including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeds $50,000.

12. Provide detailed information about violation:

Follow-up information from Enbridge indicates that costs associated with the spill totaled $52,750 as of approximately 2/26/04, with approximately 3 days of excavation that still needed to be included. In a subsequent telephone conversation between Brian Pierzina, Jay Johnson, and Patsy Bolk, on March 2, 2004, the telephonic reporting requirements were discussed, and Enbridge telephonically reported the leak to the NRC.

13. Public and/or environmental concerns in area of violation:
Primary communications had already been established as a result of the operator's telephonic report to the Minnesota State Duty Officer. An inspector was on site within an hour, and details were discussed with Central Region personnel. Failure to report to the NRC may have limited notification to some other federal agencies that would have otherwise been notified.

14a. Person Interviewed and Title:

Mark Willoughby	- Manager, Compliance and Risk Management
Jay Johnson	- Compliance Coordinator
Patsy Bolk	- Compliance Secretary

14b. Comments of person interviewed:
Following the discussion on March 2, 2004, the telephonic notice was provided to the NRC.

15. Supporting Documents/Materials

Item No.	Description (Include date)	Source of Documents	Remarks
N/A			

16. Inspector's Signature: Brian Pierzina **Date:** 3/15/04

17. Compliance History

Describe Violation/CPF No.	Date	Place	Noncompliance	Date WL
Outcome				

18. Gravity of Offense
Incident reporting is a necessary and important requirement. In this instance, due to the notice having been provided to the Minnesota State Duty Officer in a timely manner, there was less impact than if no report had been made whatsoever.

19. Degree of Culpability
The operator is solely responsible for providing notice in accordance with the regulations.

20. Ability to Continue in Business
No penalty is recommended, but it would have no effect on the operator's ability to continue in business.

21. Ability to Pay
The operator has the ability to pay. No penalty is recommended.

22. Good Faith in Attempting to Achieve Compliance
The operator likely did not anticipate costs would exceed the $50,000 threshold. As the costs accrued over the next few days, the telephonic reporting requirement may not have been considered.

23a. Proposed Remedy _____ Warning Letter _____ Civil Penalty: Recommended Amount $___ _____ Compliance Order _____ Hazardous Facility Order _____ Notice of Amendment of O&M Plan

23b. Analysis of Proposed Remedy

24. Regional Director's Signature: Date:

Memorandum

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

Central Region Office **Office of Pipeline Safety**

Date: January 27, 2006

Subject: Accident – Enbridge Pipelines
Superior Terminal – January 24, 2003

From: David Barrett, Staff Engineer

To: Accident File

Summary

On the evening of January 24, 2003, a failure occurred at Enbridge's Superior Terminal in Superior, Wisconsin. The failure occurred during a delivery from Line 4 into tankage at Superior, and as a result approximately 4,500 barrels of crude oil were spilled. The spill overwhelmed two containment ponds on the Superior Terminal property and approximately 450 barrels of oil migrated offsite to the Nemadji River. Upon discovery of the failure emergency response was initiated.

The source of the failure was where a 25" x 25" x ½" thick flat plate had been welded to 24-inch diameter terminal piping. A portion of the 24-inch pipe with failed plate was cut off and sent for metallurgical examination. Permanent repair was accomplished by installation of a 24-inch blind flange.

Metallurgical analysis determined that the failure was caused by high stress, low-cycle fatigue initiating on the inside of the pipe at the 2 o'clock position. Poor weld quality (lack of penetration) was observed, and this combined with the presence of flame-cut pipe provided a site for crack initiation and growth under pressure cycling of the pipeline. There was no evidence that internal or external corrosion contributed to the failure.

The failure occurred when the local operator at the Superior Terminal switched the incoming delivery from Tank 19 to Tank 23 at approximately 9:18 pm local time. A momentary pressure surge to approximately 197 psig occurred which caused the pipe-to-plate weld to fail. The maximum operating pressure of the facility piping is 275 psig. Upon making the switch the operator observed a lack of flow into Tank 23, and noted a crude oil smell. The Edmonton Control Center was contacted and the mainline shutdown and isolated from the terminal. Additional valves were closed within the facility as well. Emergency response was initiated including notification of Enbridge personnel and emergency responders.

The spilled oil reached the Nemadji River which was frozen approximately 2.5 to 3 feet thick at the time. The oil was removed from the ice, and the ice surface cleaned. Eventually the ice was cut and removed to assure that no oil would impact the river upon spring thaw.

Post-Accident Actions

The relief valve settings at Superior Terminal were re-set to 150 psig to reduce the potential maximum pressure during operation of terminal piping. A review of pressure test records was initiated and plan developed to assure that applicable piping system-wide was tested. All review and testing was completed by the end of 4th quarter 2004.

Attachments

Form 7000-1 – Accident Report
Metallurgical Report by CC Technologies dated 03/26/2003

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122

Form Approved
OMB No. 2137-0047

U.S. Department of Transportaion
Research and Special Programs
Administration

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date FEB 24,2003

No. 20030083 – 11564
(DOT Use Only)

INSTRUCTIONS

Important: Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov

PART A - GENERAL REPORT INFORMATION

check: ☐ Original Report ☒ Supplemental Report ☐ Final Report

1. a. Operator's OPS 5-digit Identification Number (if know) / 11169 /
2. b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if know) / /
c. Name of Operator ENBRIDGE ENERGY, LIMITED PARTNERSHIP
d. Operator street address 21 W SUPERIOR ST
e. Operator address DULUTH CLEARWATER MN 55802-2067
City, County, State and ZIP Code

IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.

2. Time and date of the accident
/ 845 / / 01 / / 24 / /2003 /
hr. month day year

3. Location of accident
(If offshore, do not complete a through d See Part C.1)

a. Latitude: 46° 41' 30" Longitude: -92° 03' 35"
(If not available, see instructions for how to provide specific location)

b. SUPERIOR DOUGLAS
City and County or Parish

c. WI 54880
State and Zip Code

d. Mile post/valve station ● or Survey Station no. ○
(whichever gives more accurate location)
1096.95

4. Telephone report
/ 634984 / / 01 / / 25 / / 2003 /
NRC Report Number *month* *day* *year*

5. Losses (Estimated)

Public/Community Losses reimbursed by operator:

Public/private property damage	$ 75,000
Cost of emergency response phase	$ 750,000
Cost of environmental remediation	$ 750,000
Other Costs	$ 25,000

(describe) ICE REMOVAL FROM THE NEMADJI RIVER

Operator Losses:

Value of product lost	$ 3,000
Value of operator property damage	$ 750,000
Other Costs	$ 500,000

(describe) TANK FEEDER LINE REPAIR AND HYDRO TESTING

Total Costs: $ 2,853,000

6. Commodity Spilled ● Yes ○ No
(If Yes, complete Parts a through c where applicable)

a. Name of commodity spilled CRUDE OIL

b. Classification of commodity spilled:
○ HVLs/other flammable or toxic fluid which is a gas at ambient conditions
○ CO_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditons
○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
● Crude oil

c. Estimated amount of commodity involved :
● **Barrels**
○ **Gallons (check only if spill is less than one barrel)**

Amounts :
Spilled : 4,500
Recovered: 4,450

CAUSES FOR SMALL SPILLS ONLY *(5 gallons to under 5 barrels)* **:** **(For large spills [5 barrels or greater] see Part H)**

○ **Corrosion** ○ **Natural Forces** ○ **Excavation Damage** ○ **Other Ouside Force Damage**
○ **Materal and/or Weld Failures** ○ **Equipment** ○ **Incorrect Operation** ○ **Other**

PART B - PREPARER AND AUTHORIZED SIGNATURE

EMILY JURGENS
(type or print) Preparer's Name and Title

(715) 394-1547
Area Code and Telephone Number

EMILY.JURGENS@ENBRIDGE.COM
Preparer's E-mail Address

Area Code and Facsimile Number

Authorized Signature (type or print) Name and Title Date Area Cod and Telephone Number

PART C - ORIGIN OF THE ACCIDENT *(Check all that apply)*

1. Additional location information
   a. Line segment name or ID 4
   b. Accident on Federal land other than Outer Continental Shelf ○ Yes ● No
   c. Is pipeline interstate? ● Yes ○ No

Offshore: ○ Yes ● No (*comple d if offshore*)
d. Area ______ Block # ______
State / / or Outer Continental Shelf ☐

2. Location of system involved (check all that apply)
   - ☒ Operator's Property
   - ☐ Pipeline Right of Way
   - ☒ High Consequence Area (HCA)? Describe HCA **NEMAJI RIVER**

3. Part of system involved in accident
   - ○ Above Ground Storage Tank
   - ○ Cavern or other below ground storage facility
   - ○ Pump/meter station; terminal/tank farm piping and equipment, including sumps
   - ● Other Specify: **END CAP OF DELIVERY LINE FAILED**
   - ○ Onshore **pipeline**, including valve sites
   - ○ Offshore **pipeline**, including platforms

   If failure occurred on ***pipeline****, complete items a - g:*

a. Type of leak or rupture
   - ○ Leak: ○ Pinhole ○ Connection Failure *(complete sec. H5)* ○ Puncture, diameter *(inches)* ______
   - ○ Rupture: ○ Circumferential - Separation ○ Longitudinal - Tear/Crack, length *(inches)* ______ Propagation Length, total, both sides *(feet)* ______
   - ○ N/A
   - ○ Other ______

b. Type of block valve used for isolation of immediate section:
   - Upstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve
   - Downstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve

c. Length of segment isolated ______ ft
d. Distance between valves ______ ft
e. Is segment configured for internal inspection tools? ○ Yes ○ No
f. Had there been an in-line inspection device run at the point of failure? ○ Yes ○ No ○ Don't Know ○ Not Possible due to physical constraints in the system
g. If Yes, type of device run *(check all that apply)*

Tool	Year run
☐ High Resolution Magnetic Flux tool	Year run: ______
☐ Low Resolution Magnetic Flux tool	Year run: ______
☐ UT tool	Year run: ______
☐ Geometry tool	Year run: ______
☐ Caliper tool	Year run: ______
☐ Crack tool	Year run: ______
☐ Hard Spot tool	Year run: ______
☐ Other tool	Year run: ______

4. Failure occurred on
   - ○ Body of Pipe ○ Pump ○ Component ○ Repair Sleeve ● Girth Weld
   - ○ Pipe Seam ○ Sump ○ Valve ○ Welded Fitting
   - ○ Scraper Trap ○ Joint ○ Metering Facility ○ Bolted Fitting
   - ○ Other *(specify)* ______

Year the component that failed was installed: / 1950 /

5. Maximum operating pressure (MOP)
   a. Estimated pressure at point and time of accident: 200 *PSIG*
   b. MOP at time of accident: 275 *PSIG*
   c. Did an overpressurization occur relating to the accident? ○ Yes ● No

PART D - MATERIAL SPECIFICATION

1. Nominal pipe size *(NPS)* / 24 / in.
2. Wall thickness .34 / in.
3. Specification API 5LX SMYS / /
4. Seam type OTHER
5. valve type ______
6. *Manufactured by* UNKNOWN *in year* / /

PART E - ENVIRONMENT

1. *Area of accident*
   - ○ Under pavement
   - ● Underground
   - ○ Inside/under building
   - ○ In open ditch
   - ○ Above ground
   - ○ Under water
   - ○ Other ______
2. *Depth of cover:* 12 *inches*

PART F - CONSEQUENCES

1. **Consequences** ***(check and complete all that apply)***

a.

	Fatalities	Injuries
Number of operator employees:	0	0
Contractor employees working for operator:	0	0
General public:	0	0
Totals:	0	0

b. Was pipeline/segment shutdown due to leak? ● Yes ○ No
If Yes, how long? 0 days 15 hours 52 minutes

c. Product ignited ○ Yes ● No d. Explosion ○ Yes ● No
e. ☐ **Evacuation** *(general public only)* / / people
Reason for Evacuation:
   - ○ Precautionary by company
   - ○ Evacuation required or initiated by public official

f. Elapsed time until area was made safe: / / hr. / / min.

2. **Environmental Impact**
   a. Wildlife Impact: Fish/aquatic ○ Yes ● No; Bird ○ Yes ● No; Terrestrial ○ Yes ● No
   b. Soil Contamination ● Yes ○ No
      If Yes, estimated number of cubic yards: 12,000
   c. Long term impact assessment performed: ○ Yes ● No
   d. Anticipated remediation ● Yes ○ No
      If Yes, Check all that apply: ☐ Surface water ☐ Groundwater ☒ Soil ☐ Vegetation ☐ Wildlife
   e. Water Contamination: ● Yes ○ No *(If Yes, provide the following)*
      Amount in water 0 barrels
      - Ocean/Seawater ○ No ○ Yes
      - Surface ○ No ● Yes
      - Groundwater ○ No ○ Yes
      - Drinking water ○ No ○ Yes *(If Yes, check below.)* ○ Private well ○ Public water intake

PART G - LEAK DETECTION INFORMATION

1. Computer based leak detection capability in place? O Yes ● No
2. Was the release intially detected by? (check one): O CPM/SCADA-based system with leak detection
   O Static shut-in test or other pressure or leak test
   ● Local operating personnel, procedures or equipment
   O Remote operating personnel, including controllers
   O Air patrol or ground surveillance
   O A third party O Other (specify) ______
3. Estimated leak duration days 0 hours 0

PART H - APPARENT CAUSE

Important: There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. Secc the instructions for guidance.

H1 - CORROSION

1. O External Corrosion
2. O Internal Corrosion

(Complete items a - e where applicable.)

a. Pipe Coating
O Bare
O Coated

b. Visual Examination
O Localized Pitting
O General Corrosion
O Other ______

c. Cause of Corrosion
O Galvanic O Atmospheric
O Stray Current O Microbiological
O Cathodic Protection Disrupted
O Stress Corrosion Cracking
O Selective Seam Corrosion
O Other ______

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
O No O Yes, Year Protection Started: /______/

e. Was pipe previously damaged in the area of corrosion?
O No O Yes => Estimated time prior to accident: /___/ years /___/ months Unknown ☐

H2 - NATURAL FORCES

3. O Earth Movement => O Earthquake O Subsidence O Landslide O Other ______
4. O Lightning
5. O Heavy Rains/Floods => O Washouts O Flotation O Mudslide O Scouring O Other ______
6. O Temperature => O Thermal stress O Frost heave O Frozen components O Other ______
7. O High Winds

H3 - EXCAVATION DAMAGE

8. O Operator Excavation Damage (including their contractors/Not Third Party)
9. O Third Party *(complete a-f)*
   a. Excavator group
   O General Public O Government O Excavator other than Operator/subcontractor
   b. Type: O Road Work O Pipeline O Water O Electric O Sewer O Phone/Cable
   O Landowner-not farming related O Farming O Raildroad
   O Other liquid or gas transmission pipeline-operator or their contractor
   O Nautical Operations O Other ______
   c. Excavation was: O Open Trench O Sub-strata (boring, directional drilling, etc...)
   d. Excavation was an ongoing activity (Month or longer) O Yes O No If Yes, Date of last contact / /
   e. Did operator get prior notification of excavation activity?
   O Yes; Date received: /___/ mo. /______/ day /___/ yr. O No
   Notification received from: O One Call System O Excavator O Contractor O Landowner
   f. Was pipeline marked as result of location request for excavation? O No O Yes (If Yes, check applicable items i - iv)
   i. Temporary markings: O Flags O Stakes O Paint
   ii. Permanent markings: O Yes O No
   iii. Marks were (check one) : O Accurate O Not Accurate
   iv. Were marks made within required time? O Yes O No

H4 - OTHER OUTSIDE FORCE DAMAGE

10. O Fire/Explosion as primary cause of failure => Fire/Explosion cause: O Man Made O Natural
11. O Car, truck or other vehicle not relating to excavation activity damaging pipe
12. O Rupture of Previously Damaged Pipe
13. O Vandalism

H5 - MATERIAL AND/OR WELD FAILURES

Material

14. O Body of Pipe =>O Dent O Gouge O Bend O Arc Burn O Other ______

15. O Component =>O Valve O Fitting O Vessel O Extruded Outlet O Other ______

16. O Joint =O Gasket O O-Ring O Threads O Other ______

Weld

17. ● Butt =O Pipe ● Fabrication O Other ______

18. O Fillet =O Branch O Hot Tap O Fitting O Repair Sleeve O Other ______

19. O Pipe Seam =>O LF ERW O DSAW O Seamless O Flash Weld
O HF ERW O SAW O Spiral O Other ______

Complete a-g if you indicate **any** *cause in part H5.*

a. Type of failure:
● Construction Defect => ● Poor Workmanship O Procedure not followed O Poor Construction Procedures
O Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? O Yes ● No

c. Was part which leaked pressure tested before accident occurred? O Yes, complete d-g ● No

d. Date of test: /______/ yr. /______/ mo. /______/ day

e. Test medium: O Water O Inert Gas O Other ______

f. Time held at test pressure: /______/ hr.

g. Estimated test pressure at point of accident: ______ *PSIG*

H6 - EQUIPMENT

20. O Malfunction of Control/Relief Equipment => O Control valve O Instrumentation O SCADA O Communications
O Block valve O Relief valve O Power failure
O Other ______

21. O Threads Stripped Broken Pipe Coupling => O Nipples O Valve Threads O Dresser Couplings
O Other ______

22. O Seal Failure =>O Gasket O O-Ring O Seal/Pump Packing
O Other ______

H7 - INCORRECT OPERATION

23. O Incorrect Operation

a. Type O Inadequate Procedures O Inadequate Safety Practices O Failure to Follow Procedures
O Other ______

b. Number of employees involved who failed a post-accident test: drug test: /______/ alcohol test /______/

H8 - OTHER

24. O Miscellaneous, *describe:* ______

25. O Unknown
O Investigation Complete O Still Under Investigation (*Submit a supplemental report when investigation is complete*)

PART I - NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT (Attach additional sheets as necessary)

Refer to ATTACHMENT PART I - NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT

ATTACHMENT PART I - NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT

ON JANUARY 24, 2003, AN INCIDENT OCCURRED AT OUR SUPERIOR, WISCONSIN TERMINAL FACILITIES DURING A SWING FROM TANK 19 TO TANK 23 OFF LINE 4. WHILE OUR INVESTIGATION IS ONGOING, INITIAL INDICATIONS ARE THAT AN END CAP OFF OF A 24" DELIVERY LINE FAILED DURING A RELATIVELY MINOR PRESSURE SURGE CAUSED BY AN OPERATOR MOMENTARILY SWINGING AGAINST A CLOSED TERMINAL VALVE DURING A DELIVERY. THIS RESULTED IN THE RELEASE OF APPROXIMATELY 4500 BARRELS CRUDE OIL, A PORTION OF WHICH MIGRATED OFF SITE TO THE NEARBY FROZEN NEMADJI RIVER. IT IS ESTIMATED THAT APPROXIMATELY 450 BARRELS OF OIL REACHED THE RIVER; HOWEVER, INFORMATION GATHERED FROM NUMEROUS MONITORING WELLS INDICATED THAT THE PRODUCT WAS CONTAINED ABOVE THE ICE AND THAT IT DID NOT REACH THE ACTUAL WATERS OF THE RIVER. CLEANUP OF THE ICE HAS BEEN COMPLETED, AND CLEANUP IS STILL IN PROGRESS FOR THE REMAINDER OF THE AFFECTED FACILITIES.

FINAL REPORT
F 2264-01F

FAILURE ANALYSIS OF SUPERIOR STATION TERMINAL PIPE

PREPARED FOR
ENBRIDGE PIPELINES INC.
EDMONTON, ALBERTA CANADA

PREPARED BY
CC TECHNOLOGIES LABORATORIES, INC.
CARL E. JASKE, PH.D., P.E.
AND STANLEY H. GELLES, SC.D.

MARCH 26, 2003

CC Technologies
6141 AVERY ROAD
DUBLIN, OHIO 43016-8761 USA
614.761.1214 • 614.761.1633 fax
www.cctechnologies.com

DISCLAIMER

This report documents work performed by CC Technologies Laboratories, Inc. *(CC Technologies)* Dublin, Ohio USA, for Enbridge Pipelines Inc., Edmonton, Alberta Canada. Neither CC Technologies nor any person acting on behalf of CC Technologies:

- assumes any liability for consequences or damages resulting from the use, misuse, or reliance upon the information disclosed in this report.
- makes any warranty or representations that the use of any information, apparatus, method, or process disclosed in this report may not infringe on privately-owned rights.

EXECUTIVE SUMMARY

CC Technologies Laboratories, Inc. (*CC Technologies*) was contracted by Enbridge Pipelines Inc. (*Enbridge*) to analyze a pipeline failure that occurred at their Superior Terminal on January 24, 2003. The failed piece from the end of a 24-inch diameter branch line and two small glass jars containing an oil sample from a location in the pipeline adjacent to the failed piece were sent to CC Technologies for this work.

The fracture occurred at a weld between a 0.50-inch thick end plate and the 0.35-inch thick pipe end. The weld was of poor quality, as indicated by porosity, irregular weld contour, and lack of penetration. The end plate not being flush against the end of the pipe resulted in a large gap between the end of the pipe and the surface of the plate in regions where there was lack of weld penetration.

The failure was caused by high-stress, low-cycle fatigue cracking that initiated on the inside of the pipe in the notch at the weld root near the 2:00 o'clock position. The local stress level in the crack-initiation region was not calculated, but based on the ductile dimpled tearing observed on the fracture surface, it exceeded the yield strength of the weld metal. The crack propagated by low-cycle fatigue until it reached a critical size where sudden rupture occurred by brittle cleavage fracture. The fatigue loading was from pressure fluctuations in the pipeline, while the high stress was a result of the poor weld detail and quality.

Some shallow isolated corrosion pitting was observed near the top on the pipe interior. The worst pits were 0.014 inch (4% of the pipe wall) to 0.025 inch deep (7% of the pipe wall). Most of these were less than 0.10 inch long and wide. The two biggest pits observed were 0.16 inch by 0.10 inch and 0.14 inch by 0.06 inch. Overall, there was no evidence of internal corrosion on the pipe or end plate contributing to the failure.

The end of the pipe had not been machined to prepare it for welding; a flame-cut surface was found on the pipe end. The microstructures of the pipe and plate were typical of those expected for carbon-manganese pipeline steel.

Analysis of the oil samples showed that they were 95.6% oil and 4.4% solids. No free water separated from the oil. Qualitative tests revealed that the solids contained some iron sulfide and some carbonate. Quantitative analysis of the acid-soluble solids revealed the presence of 5.19% Ca, 1.26% Mg, 4.61% Fe, 0.054% Mn, and 0.074% Cl. Chloride is a contaminant that could cause internal corrosion, although no corrosion was observed to contribute to the failure. No evidence of any other contaminant that might cause internal corrosion was found. No analysis for biological species was performed because there was no free water in the sample and no evidence that any such species were likely to be present in the sample.

CONTENTS

TABLES

FIGURES

FIGURES (continued)

INTRODUCTION

A crude oil pipeline ruptured at the Superior (Wisconsin) Terminal of Enbridge Energy Partners, L.P. during the night of Friday, January 24, 2003. The failure occurred at the capped end of a 24-inch diameter branch pipeline. On Wednesday, January 29, 2003, Enbridge Pipelines Inc. (*Enbridge*) then contracted CC Technologies Laboratories, Inc. (*CC Technologies*) to perform a failure analysis of the ruptured pipeline.

Figure 1 shows a photograph of the failed piece of the pipeline after it was cut off the end of the branch and before it was shipped to CC Technologies. The piece consisted of an approximately 3-inch long ring of the 24-inch diameter pipe with a partially attached 25 by 25-inch plate. The plate had been welded to the end of the pipe, and the failure occurred at the weld between the pipe and the plate.

Along with the failed pipe piece, two glass jars (2-ounce) about 50% full of oil taken from the inside of the pipeline at a location adjacent to the failed piece were received at CC Technologies. Enbridge reported that the samples were taken at about 10:00 PM and the air temperature was below 0° F at the time. The contents of both jars were taken from the same location and considered to be one sample.

The objective of the work was to identify the failure mechanism and the cause of the pipeline failure.

The work performed by CC Technologies consisted of visually examining the fracture surfaces before and after cleaning them, removing small samples and examining them using a scanning electron microscope (SEM), analyzing surface deposits on one SEM sample by means of energy dispersive x-ray spectroscopy (EDS), metallographic preparation and examination of small samples from the failed piece of pipe, and analysis of oil samples from the failed pipeline. These four tasks are discussed in the following sections of this report.

VISUAL EXAMINATION

Figures 2 and 3 show the piece of pipe in the condition as received at CC Technologies. The 12 o'clock position was marked on the pipe and is on the right-hand side in Figure 2. The maximum opening between the pipe and end plate was approximately 3.5 inches and was near the 2 o'clock position, as shown in Figure 3. As can be seen in Figure 2, a section of the pipe approximately opposite of the main fracture had been cut from the ring after the photograph of Figure 1 was taken. Enbridge reported that the removed piece was used for purposes of material identification as part of the pipeline repair. Dimensions of the piece were measured and the results are summarized in Table 1.

There were no indications of external or internal corrosion deeper than 10% of the pipe wall thickness. Some isolated, shallow corrosion pits were observed on the inside surface of the pipe. These pits were located near the top of the pipe in the 10:30 to 1:30 o'clock area. The worst pits ranged in depth from 0.014 inch to 0.025 inch. Most of these were less than 0.10 inch long and wide. The two biggest pits observed were 0.16 inch by 0.10 inch and 0.14 inch by 0.06 inch.

Visual examination revealed that the fracture surface on the plate had been abrasively cleaned but that most of the fracture surface on the end of the pipe was still covered with a black oily product. In order to better view the latter surface, the fractured segment of the pipe was cut axially at two locations to produce a C-shaped ring of the pipe.

Figure 4 shows the piece of pipe with markings to indicate (1) the ends of the through-wall flaw (fracture), (2) the 3:00, 6:00, 9:00, and 12:00 o'clock positions, (3) the two locations for making the axial cuts of the pipe, and (4) the location of a metallographic (met) sample from the intact portion of the weld (at approximately the 8:00 o'clock position). The dots marked between the 3:00 and 12:00 o'clock positions are one-inch intervals starting from the 3:00 o'clock position.

The fracture origin area was near the 2:00 o'clock position, which was the area of the maximum gap as shown in Figure 3. The fracture surface in this general area was below the inside surface of the end plate as shown by the examples in Figures 5 and 6. Figure 7 shows an area where the fracture was through weld metal attached to the end plate; an irregular weld contour was observed in this area.

As schematically illustrated in Figure 8, the following three regions were observed on the pipe fracture surface:

- Region 1 is the flame cut end of the pipe; in the origin area it is about 0.30 inches wide. There was no weld metal fusion in this region.
- Region 2 is the surface of the weld metal; in the origin area it is about 0.13 inches wide. There was no fusion of the weld metal to the plate in this region.
- Region 3 is actual metal fracture; in the origin area it is about 0.13 to 0.18 inches wide. This was the only region of weld fusion between the end of the pipe and plate

Although these three regions were observed when visually examining the uncleaned surfaces using a stereomicroscope, they are not clearly revealed in the photographs of those surfaces (Figures 5-7 and 9-10). These regions are identified in the photographs of the cleaned fracture surfaces in the next section of the report.

The metal fracture (Region 3) shows indications of banding on the surface. This is an indication of progressive crack growth by fatigue. These features were examined in more detail using the SEM as discussed in the next section. Figures 9 and 10 show the typical appearance of different areas of the pipe fracture surface before cleaning.

SEM / EDS STUDIES

Five SEM fracture samples were cut from the pipe at locations selected based on the visual examinations. Three of these (SEM 1, SEM 2, and SEM 3) were cleaned and examined to characterize different areas of the fracture surface. Sample SEM 4 was cleaned but not examined. Sample SEM 5 was removed and left in the as-received condition for EDS. It was dry cut from the pipe to avoid contamination of the black film-like surface deposit.

The location and depth of weld penetration for the five SEM samples are given in Table 2. SEM 1 was from the failure initiation area near the 2:00 o'clock position. The amount of weld penetration was measured from the outside surface of the pipe. Depth of weld penetration is listed both as the measured value and as a percentage of the 0.350-inch measured pipe wall thickness. It ranges from 11% to 100%, but four of the five values are well below 100% indicating lack of penetration. The penetration depth was lowest, only 11%, in the initiation area. The area with the least penetration would experience the highest local stress under internal pressure loading, so it is not surprising that it is the area of crack initiation.

The condition of each SEM sample and the key observations made during the examination of each sample are summarized in the following subsections.

SEM 1

Sample SEM 1 was taken from about the 2:00 o'clock position. It was cleaned for fractographic observations using an inhibited acid solution. Figure 11 shows a photograph of this sample. The morphology of the fracture was almost entirely low-cycle fatigue as indicated by the banded or striated appearance at low magnification and by the bands of ductile dimpled tearing at high magnification. Figure 12 shows an overview of these low-cycle fatigue features on the fracture surface of Sample SEM 1 at 10X magnification. Figures 13 and 14 show the features at higher magnifications of 50X and 200X, respectively. The low-cycle fatigue fracture surface exhibited ductile dimple tearing, which is indicative of high stress. Weld porosity was also observed on the fracture surface (see Figures 12 and 13). Based on the observed fracture morphology, it was concluded that the cracking initiated on the inside surface of the weld and progressed through the weld metal to the outside surface.

SEM 2

Sample SEM 2 was taken from about the 3:30 o'clock position. It was cleaned for fractographic observations using an inhibited acid solution. Figure 15 shows a photograph of this sample. Fracture on this sample consisted of an area of low-cycle fatigue morphology near the pipe inside surface and a relatively thin zone of cleavage failure near the outside surface. Figure 16 shows an overview of the low-cycle fatigue and cleavage features on the fracture surface of Sample SEM 2 at 11X magnification. Figure 17 shows the transition between the region of low-cycle fatigue (banded or striated area in the upper portion of photograph) and cleavage fracture (faceted area in the lower portion of photograph) at 50X magnification. Figures 18 and 19 show the details of the low-cycle fatigue and cleavage, respectively, at a higher magnification of 200X. Based on the observed fracture morphology, it was concluded that the cracking initiated on the inside surface of the weld and progressed into the weld metal until the crack reached a critical size where it rapidly propagated to the outside surface by brittle cleavage fracture when the final failure occurred.

SEM 3

Sample SEM 3 was taken from about the 4:00 o'clock position. It was cleaned for fractographic observations using an inhibited acid solution. Figure 20 shows a photograph of this sample. The fracture on this sample had a completely cleavage morphology. Figure 21 shows an overview of those cleavage features on the fracture surface at 10X magnification. Figure 22 shows details of the cleavage features at a higher magnification of 200X. The cleavage fracture morphology indicates that the crack rapidly propagated through this area when the final fracture occurred.

SEM 4

Sample SEM 4 was taken from near the 12:00 o'clock position. It was cleaned using an inhibited acid solution, but it was not examined.

SEM 5

Sample SEM 5 was taken from near the 11:30 o'clock position for EDS of the black surface deposit/film. Foreign material containing C, S, Si, Ca, P, K Cl, Al and O was detected on the flame cut end surface of the pipe and fracture surface. Figures 23 and 24 show the EDS results.

METALLOGRAPHIC EXAMINATIONS

Four samples were cut from the pipe piece, mounted, polished, etched, and examined using standard metallographic procedures. The location and key observations for each metallographic (MET) sample are summarized in the following subsections.

MET 0

Sample MET 0 was taken from about the 8:00 o'clock position, which was opposite the fracture origin area and where the pipe was still attached to the end plate. This is the sample identified as "MET SAMPLE" in Figure 4. Figure 25 shows this sample after polishing and etching. There was a large gap between the end of the pipe and the plate. The end of the pipe was flame cut with no machined weld preparation. Cracking had initiated from a notch at the root of the weld. As can be seen in Figures 25 and 26, the depth of weld penetration was about 30%.

Figure 26 shows the crack and microstructure in Sample MET 0. The crack was clearly growing through the weld metal and started at the weld root on the inside of the pipe. The darkly etched band on the end of the pipe reveals carburization from the flame cutting. Figure 27 shows the carburized microstructure near the flame-cut end of the pipe, while Figure 28 shows the decarburized microstructure near the inside surface of the end plate. The flame cutting caused carburization. Hot rolling of the plate during manufacturing most likely caused the decarburization. Both the carburized and decarburized microstructures would be expected to initiate fatigue cracking more easily than a typical ferritic-pearlitic microstructure. The interior portions of the pipe and plate, away from the surfaces, had ferritic-pearlitic microstructures typical of those expected for carbon-manganese pipeline steels, as shown in Figures 29 and 30, respectively.

MET 1

Sample MET 1 was taken from about the 2:00 o'clock position adjacent to Sample SEM 1. The low-cycle fatigue fracture morphology was confirmed. Poor weld penetration was noted. Figure 31 shows a typical section through the fracture surface. The serrated, tearing appearance of the fracture surface in the region of low-cycle fatigue cracking (Region 3 of Figure 8), confirms the periodic ductile tearing observed in the SEM studies.

MET 2

Sample MET 2 was taken from about the 3:30 o'clock position adjacent to Sample SEM 2. The combined low-cycle fatigue and cleavage fracture morphology was confirmed. Figure 32 shows the serrated, tearing appearance in the region of low-cycle fatigue. Figures 33 and 34 show the microstructures along the flame-cut pipe end (Region 1 of Figure 8) and the weld surface (Region 2 of Figure 8). Figure 35 shows the microstructure along the cleavage fracture surface (Region 3 of Figure 8).

MET 3

Sample MET 3 was taken from about the 4:00 o'clock position adjacent to Sample SEM 3. The cleavage fracture morphology was confirmed in the examination of this sample.

ANALYSIS OF OIL SAMPLES

This section of the report first describes the experimental approach used to prepare and analyze the oil samples. Then, the results are presented.

Experimental Approach for Oil Analysis

Both jars of oil were shaken to mix any water or solids that might have separated from the oil. Their contents were then poured into a graduated tube and centrifuged for 10 minutes at 1344 rpm to separate any water or solid fractions that were present.

Solids that were centrifuged from the oil were alternately washed in xylene and hexane to remove residual oil. The washed solids were air dried and quantitatively analyzed for calcium, magnesium, iron, manganese, and chloride. A small portion of the solids was also qualitatively tested for the presence of carbonate and sulfide.

For the quantitative analysis, the solids were digested in nitric acid. Metals were determined by flame atomic absorption spectroscopy and chloride was determined by titration with mercuric nitrate.

For the qualitative analysis, a portion of the solids was acidized with 10% hydrochloric acid. The presence of carbonate was ascertained by the relative amount of effervescence that occurred. The presence of sulfide was ascertained by the reaction of moistened lead acetate paper to the gas producing from the reaction with the acid.

Results of Oil Analysis

Centrifuging showed the 45 mL sample to be 95.6% oil and 4.4% solids. No water freely separated from the oil. The bulk of the solids were medium brown in color. A trace of magnetic iron was present. Acidification of a trace amount of dull, black-colored solids yielded sulfide gas, which suggested the presence of some iron sulfide. A portion of the brown-colored solids readily effervesced, which suggested the presence of carbonate.

Quantitative analysis of the solids showed the following composition:

Calcium	5.19%
Magnesium	1.26%
Iron	4.61%
Manganese	0.054%
Chloride	0.074%

These results are typical of those expected for crude oil. The chloride contaminant might cause internal corrosion. None of the other contaminants are expected to cause significant internal corrosion. No analysis for biological species was performed because there was no free water in the sample and no evidence that any such species were likely to be present in the sample.

CONCLUSIONS

The results of this analysis showed that the failure initiated in the vicinity of the 2:00 o'clock area of the pipe to end plate weld. This was a region of lack of weld penetration. The cracking of the weld initiated at a notch on the inside of the pipe created by the gap between the end of the pipe and the end plate by a high-stress, low-cycle fatigue mechanism. The poor weld detail and quality coupled with the presence of flame-cut material on the end of the pipe provide a site for crack initiation and growth under pressure cycling of the pipeline. Once the crack grew through the wall in the area of initiation and grew far enough around the circumference to reach a critical size, sudden fracture occurred by brittle cleavage.

The final cleavage fracture implies that the weld metal had low fracture toughness because cleavage is a low-toughness fracture mechanism. The low fracture toughness was most likely a combined result of poor weld quality and low ambient temperature at the time of failure. There was no evidence of external or internal corrosion that contributed to the failure.

Table 1. Measured dimensions of piece of failed pipe.

Dimension	Value, inches
Pipe outside diameter	24
Pipe wall thickness	0.350
Plate wall thickness	0.500
Plate size	25 × 25
Range of worst internal pit depths (these were located in the 10:30 to 1:30 o'clock area of the pipe)	0.014 – 0.025

Table 2. Measured depth of weld penetration from outer surface of pipe.

Sample Identification	Location Around Pipe, o'clock position	Depth of Weld Penetration Into Pipe Wall, inches	Depth of Weld Penetration Into Pipe Wall, %
SEM 1	2:00	0.04	11
SEM 2	3:30	0.24	68
SEM 3	4:00	0.35	100
SEM 4	12:00	0.16	45
SEM 5	11:30	0.08	22

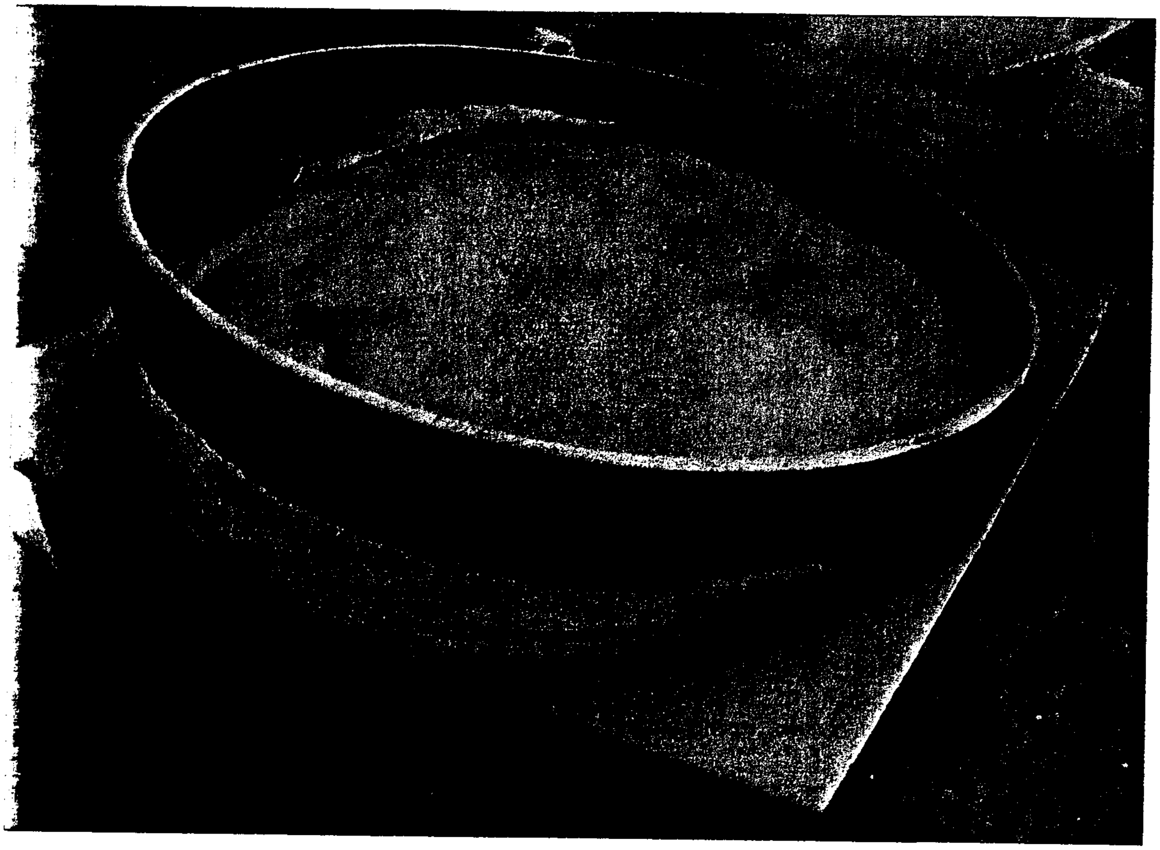


Figure 1. Photograph of piece of failed pipe before shipping to CC Technologies (courtesy of Enbridge Pipelines Inc.).

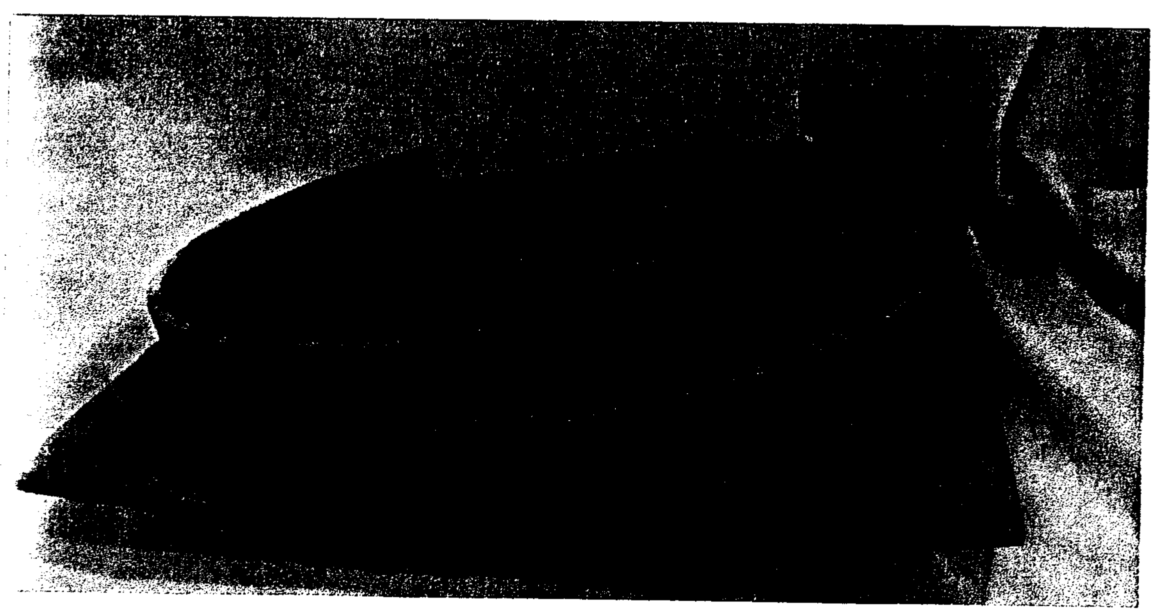


Figure 2. Photograph of piece of failed pipe as received at CC Technologies.

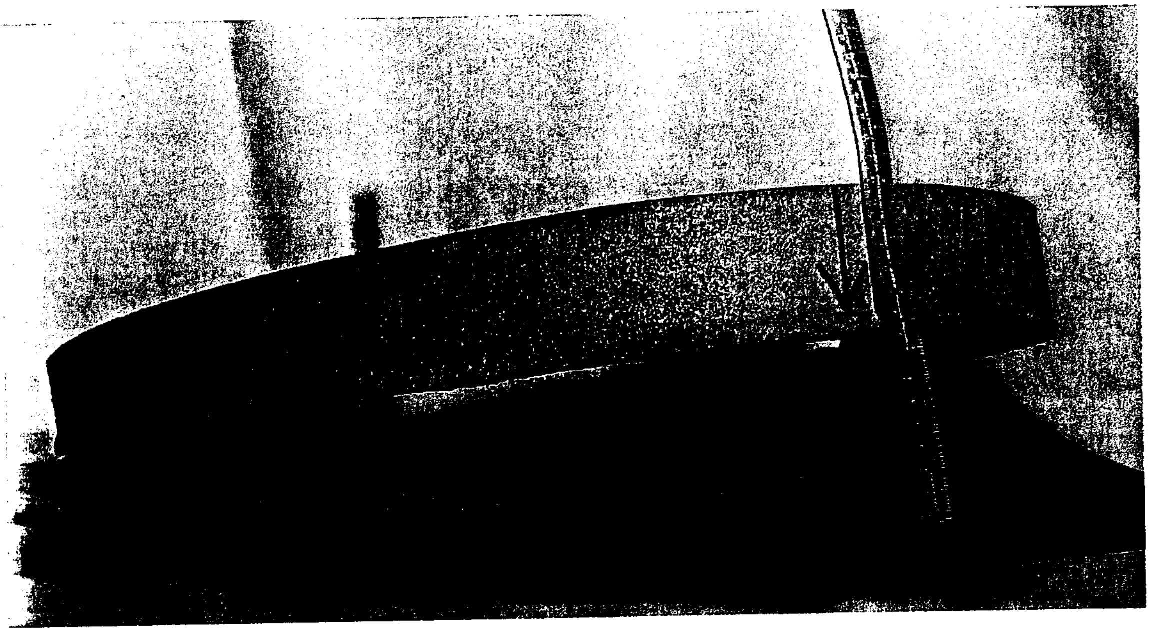


Figure 3. Photograph showing gap between pipe and end plate, as received.

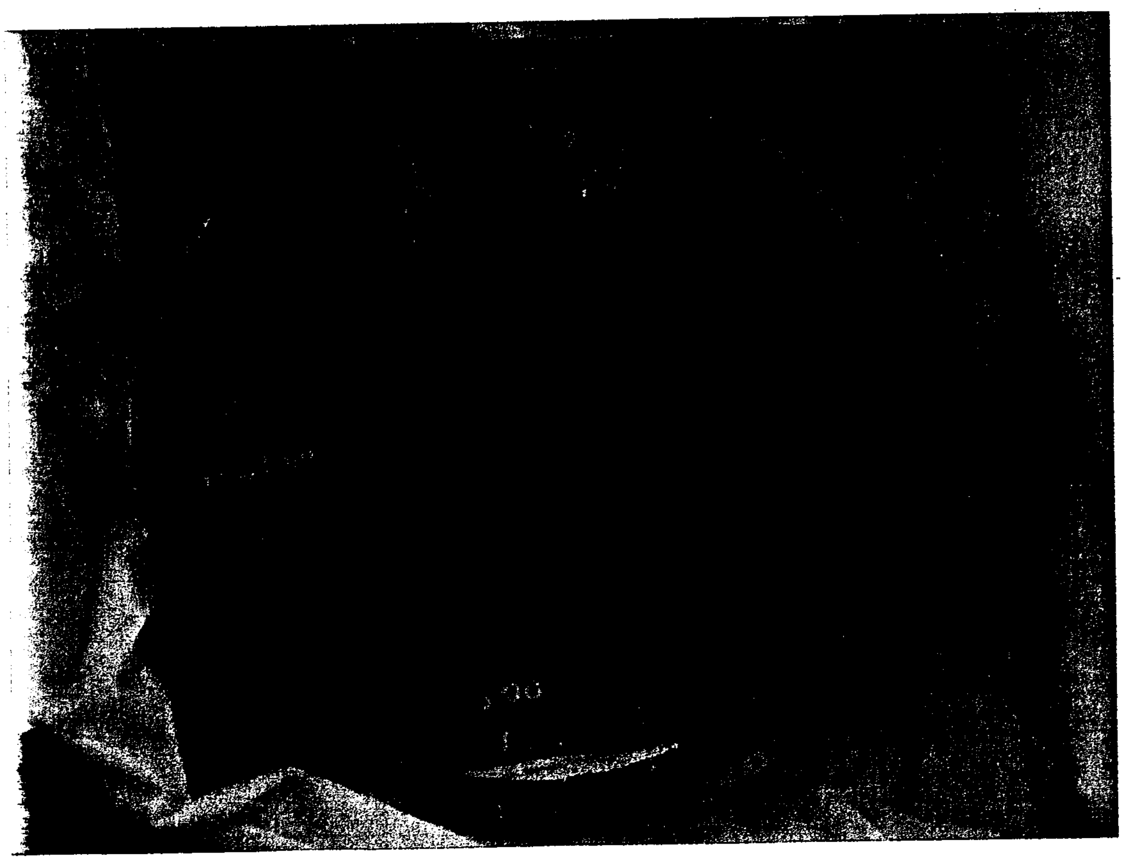


Figure 4. Photograph of piece of failed pipe marked for cutting of samples.

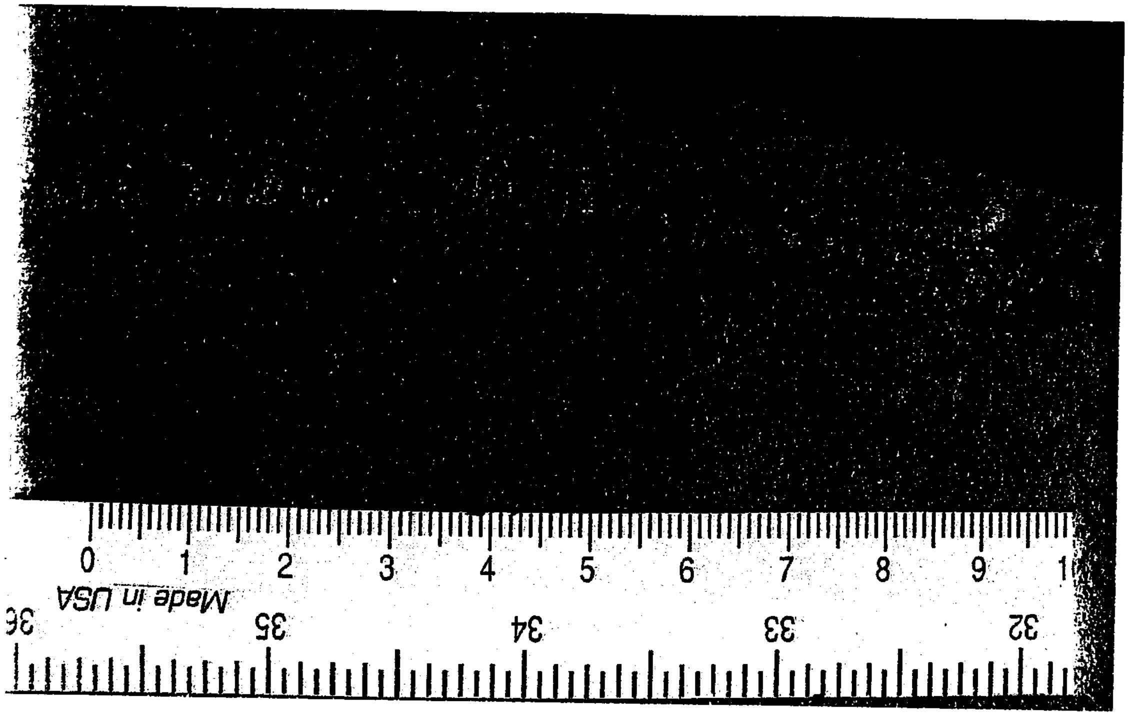


Figure 5. Fracture surface on plate at 11:15 o'clock position.

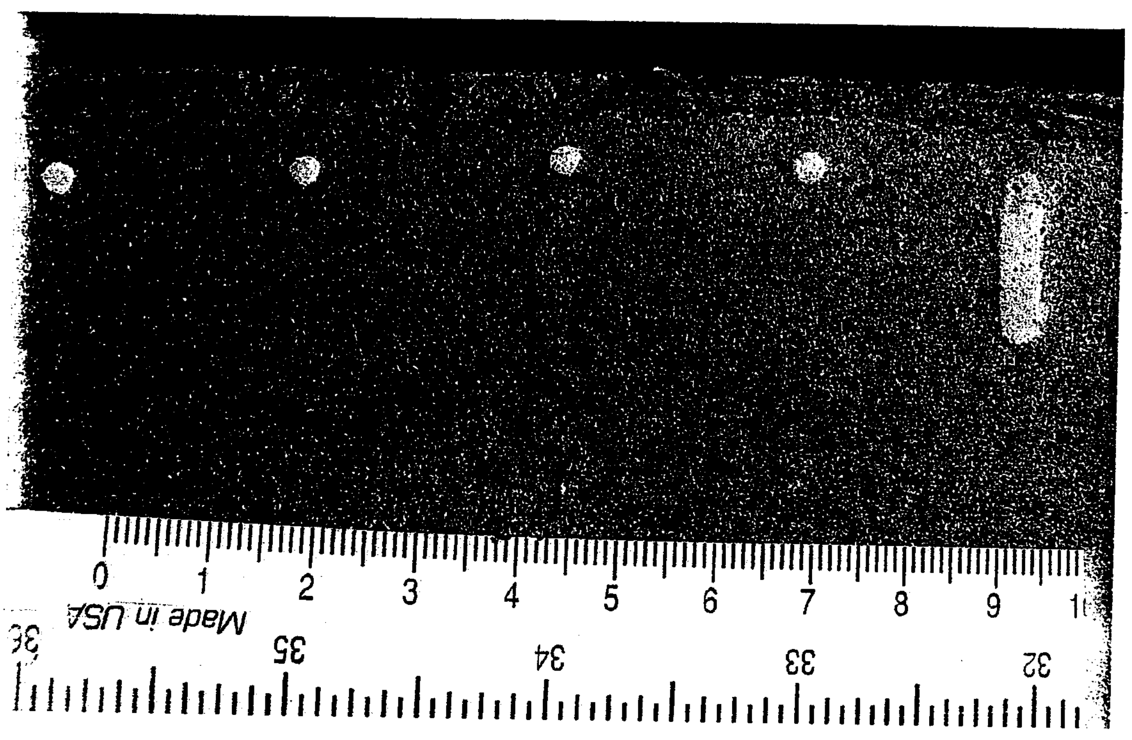


Figure 6. Fracture surface on plate at 3:00 o'clock position.

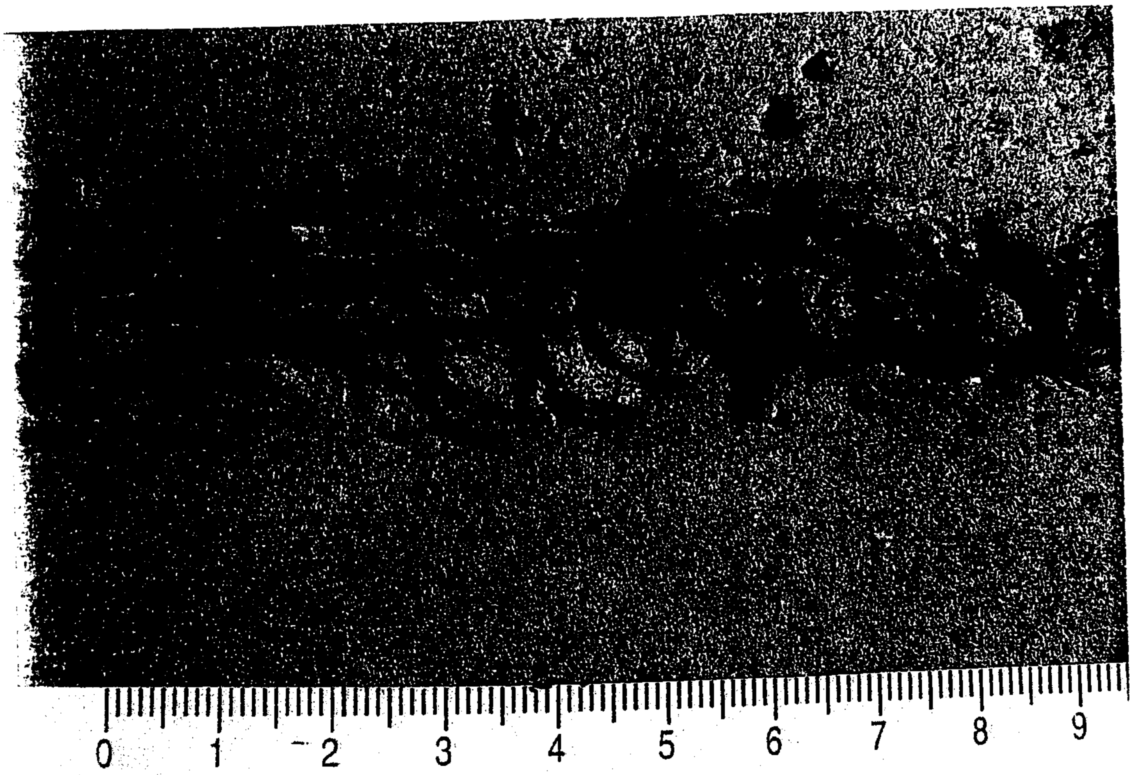


Figure 7. Fracture surface on plate at 7:30 o'clock position.

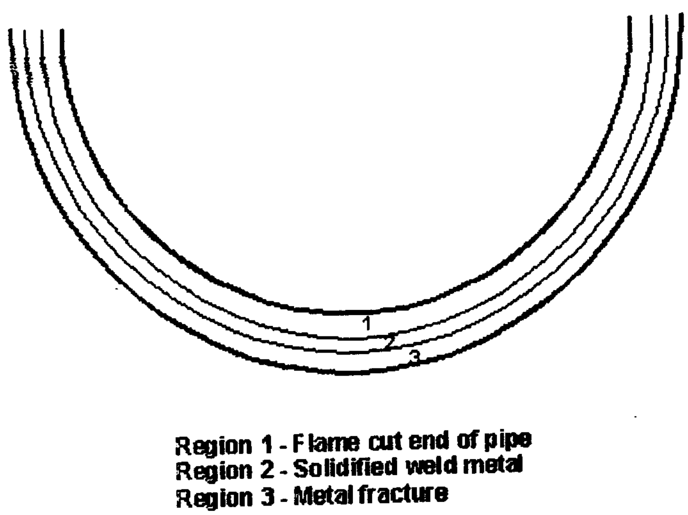


Figure 8. Schematic illustration of three regions observed on pipe fracture surface.

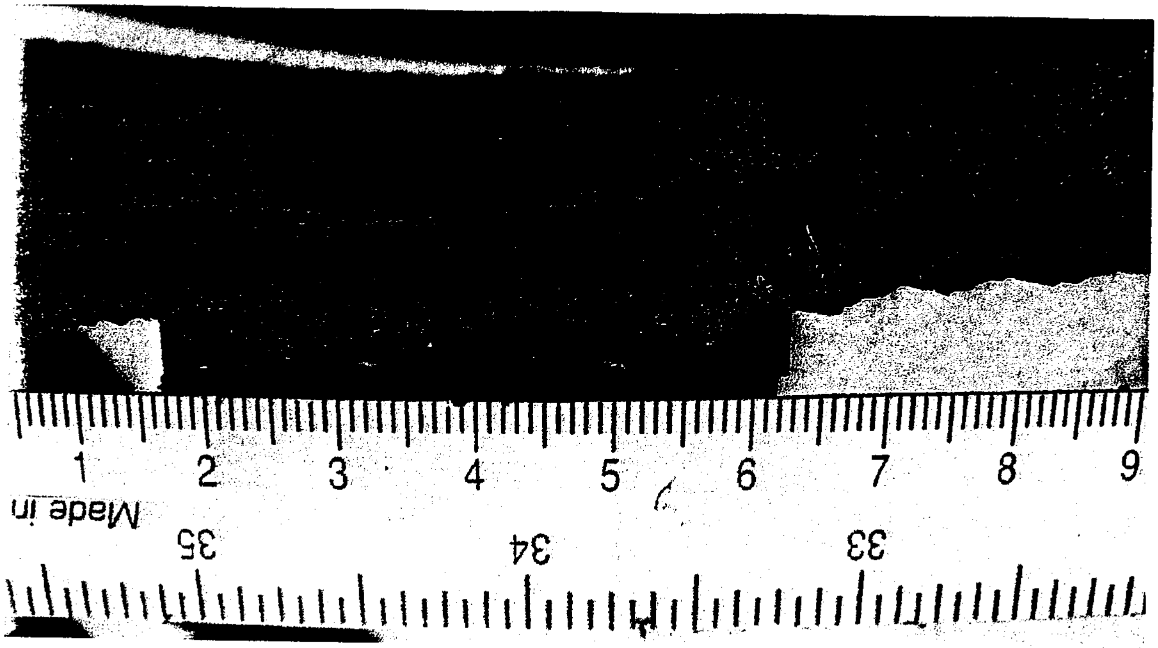


Figure 9. Uncleaned fracture surface of pipe at 12:15 o'clock position. (Outside surface of pipe is at bottom and inside surface is at top.)

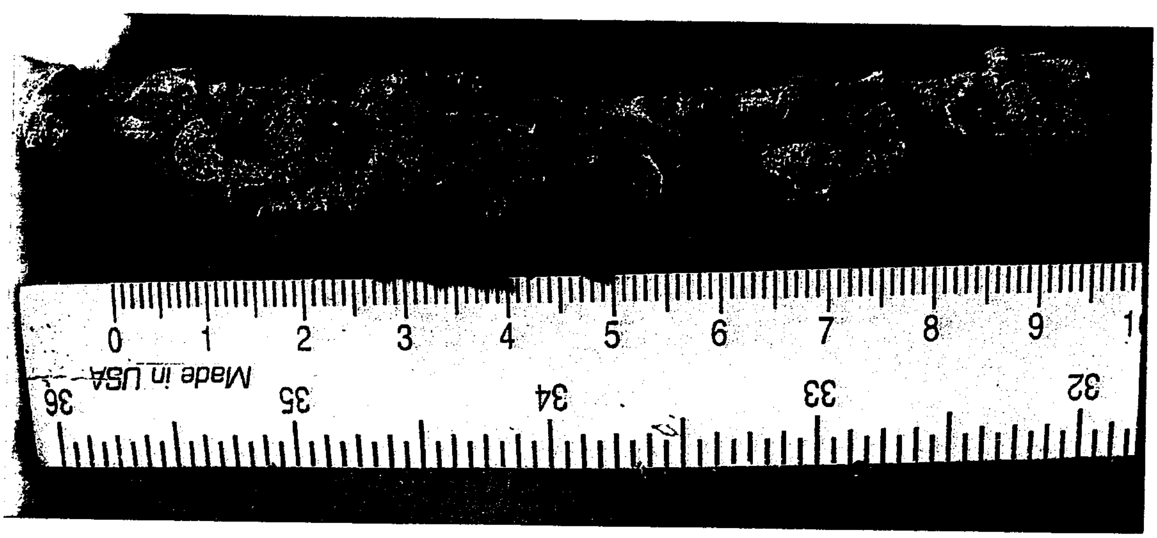


Figure 10. Uncleaned fracture surface of pipe at 4:30 o'clock position. (Outside surface of pipe is at bottom and inside surface is at top.)

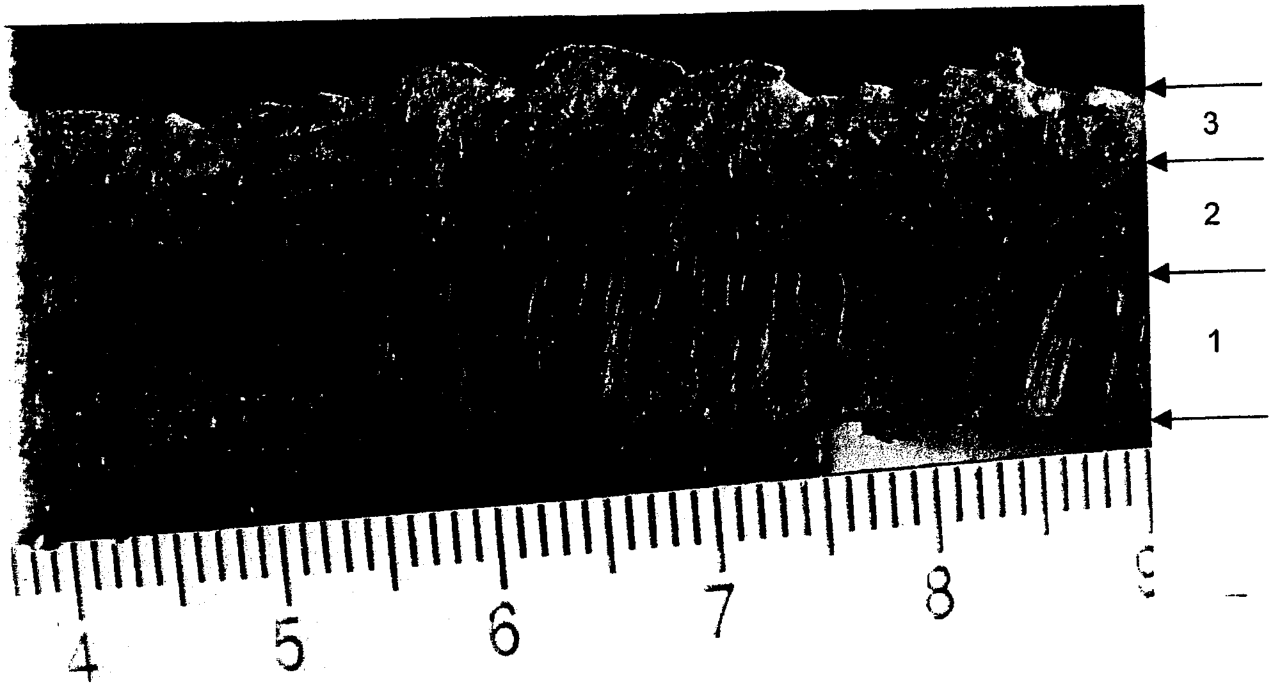


Figure 11. Cleaned fracture surface of Sample SEM 1 from the 2:00 o'clock position. (Outside surface of pipe is at top and inside surface is at bottom. 1 – Flame cut pipe end, 2 – Weld metal surface, 3 – Fractured metal).

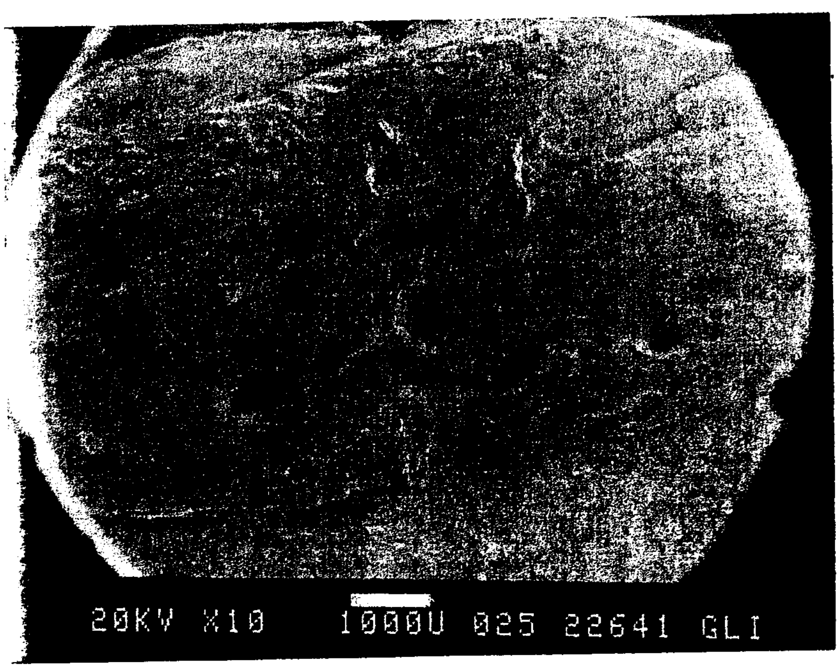


Figure 12. Overview of weld fracture on Sample SEM 1.

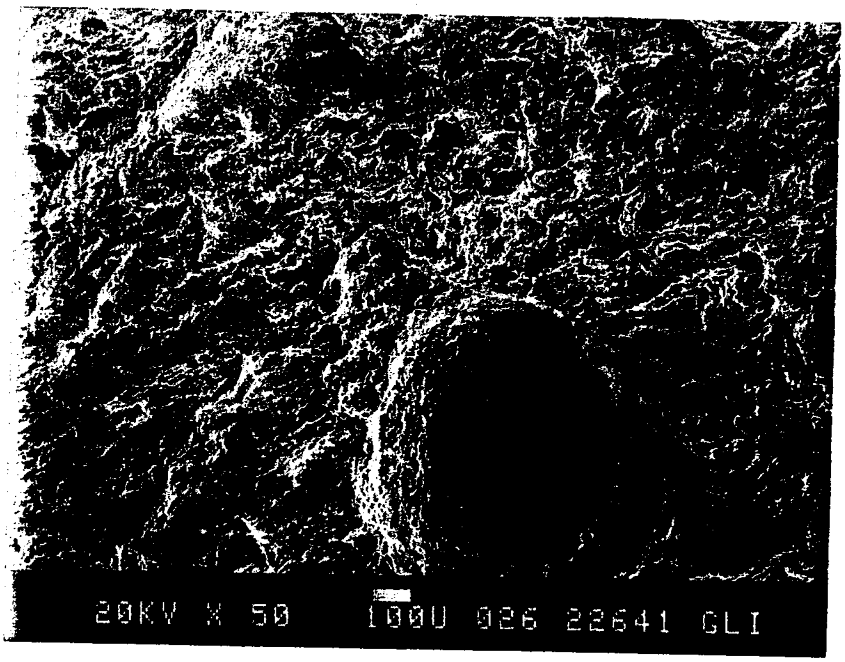


Figure 13. Ductile low-cycle fatigue and porosity on fracture face of SEM 1.

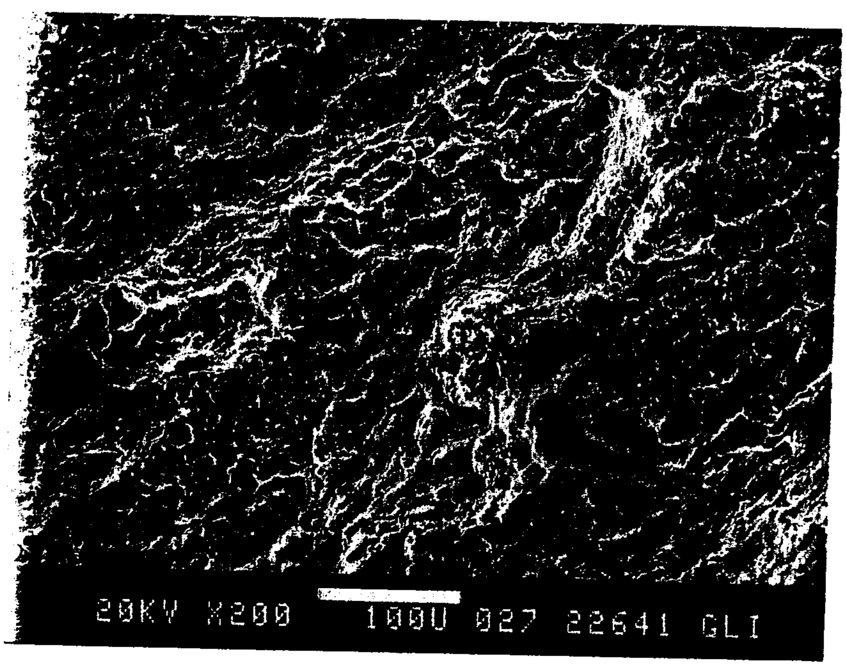


Figure 14. Details of ductile low-cycle fatigue on fracture face of SEM 1.

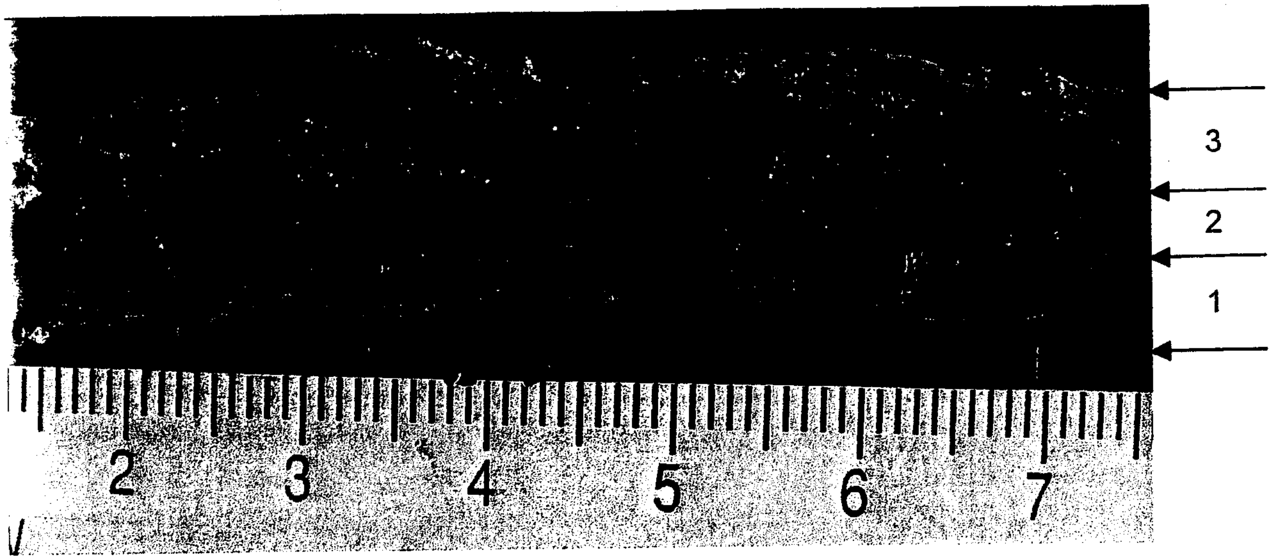


Figure 15. Cleaned fracture surface of Sample SEM 2 from the 3:30 o'clock position. (Outside surface of pipe is at top and inside surface is at bottom. 1 – Flame cut pipe end, 2 – Weld metal surface, 3 – Fractured metal).

Figure 16. Overview of weld fracture on Sample SEM 2.

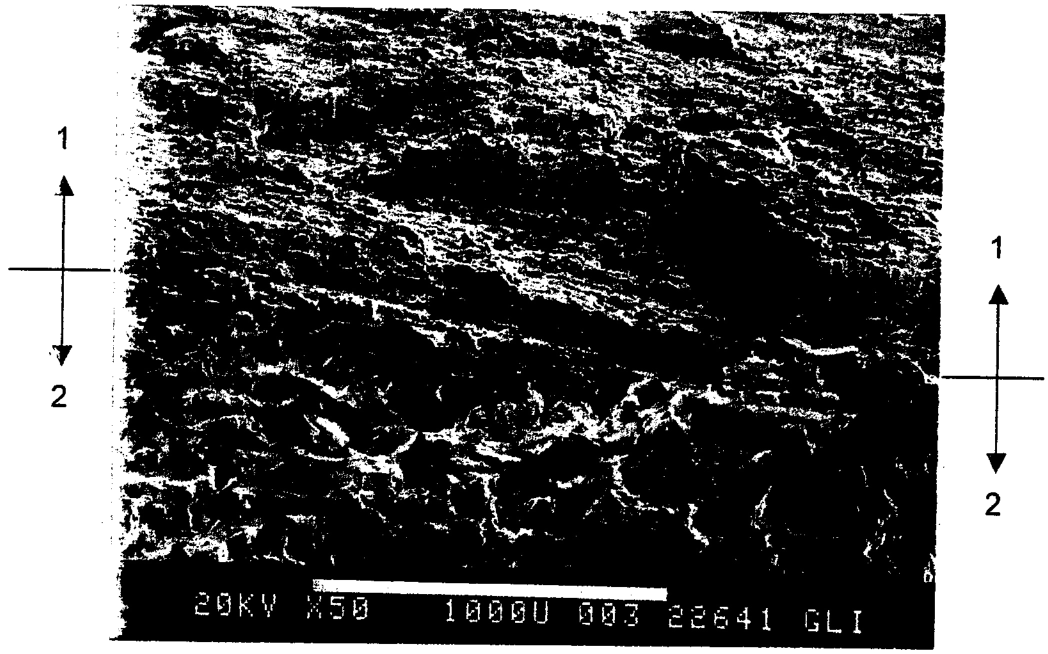


Figure 17. Ductile low-cycle fatigue and cleavage on fracture face of SEM 2. (1 – Fatigue and 2 – Cleavage)

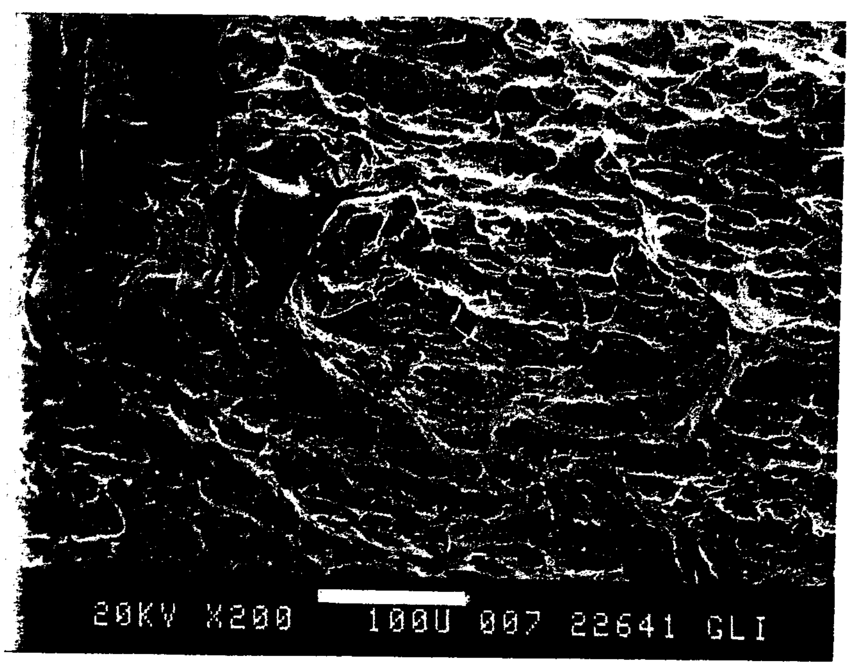


Figure 18. Details of ductile low-cycle fatigue on fracture face of SEM 2.

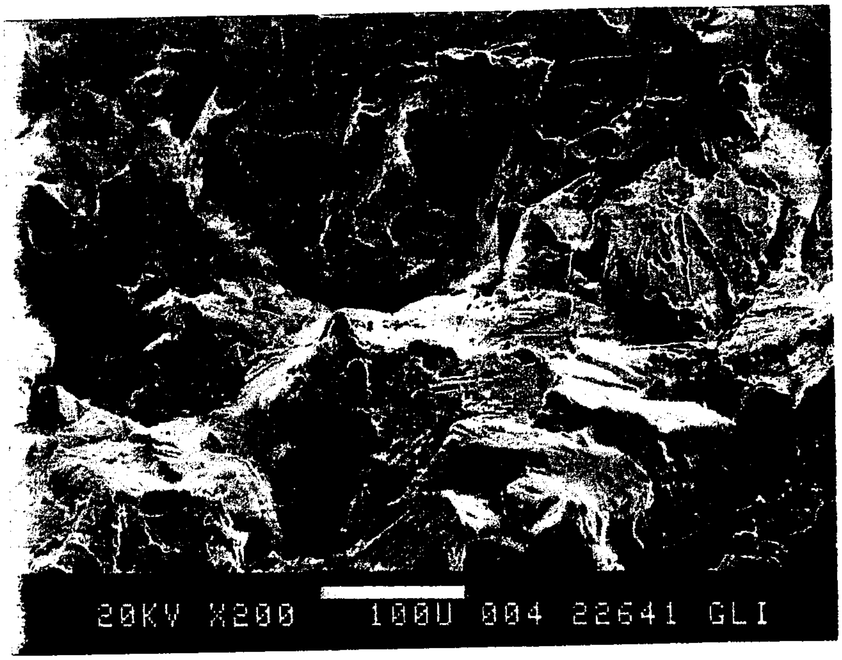


Figure 19. Details of cleavage on fracture face of SEM 2.

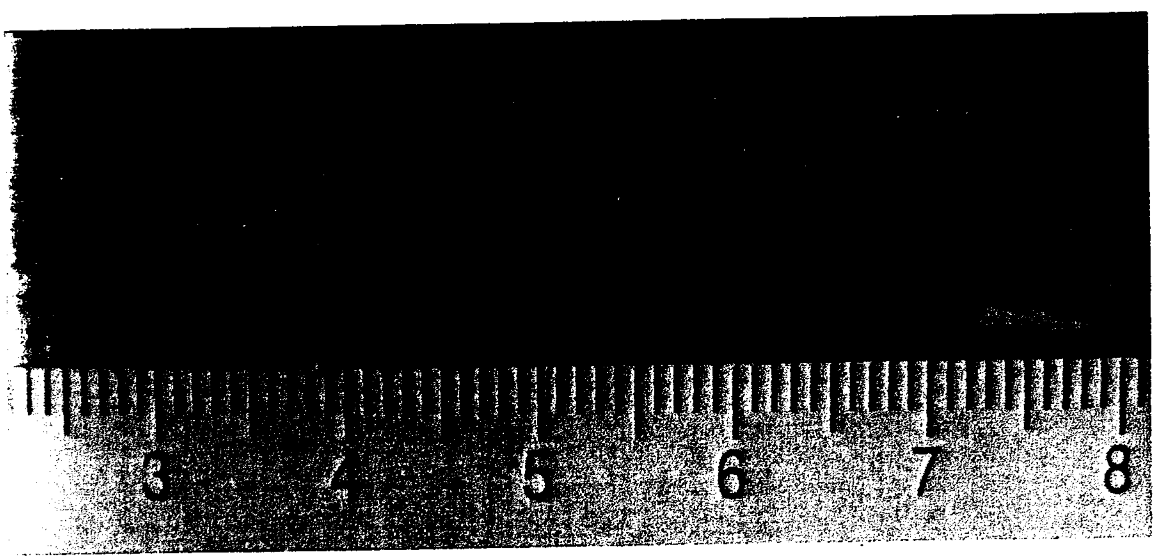


Figure 20. Cleaned fracture surface of Sample SEM 3 from the 4:00 o'clock position. (Outside surface of pipe is at top and inside surface is at bottom.)

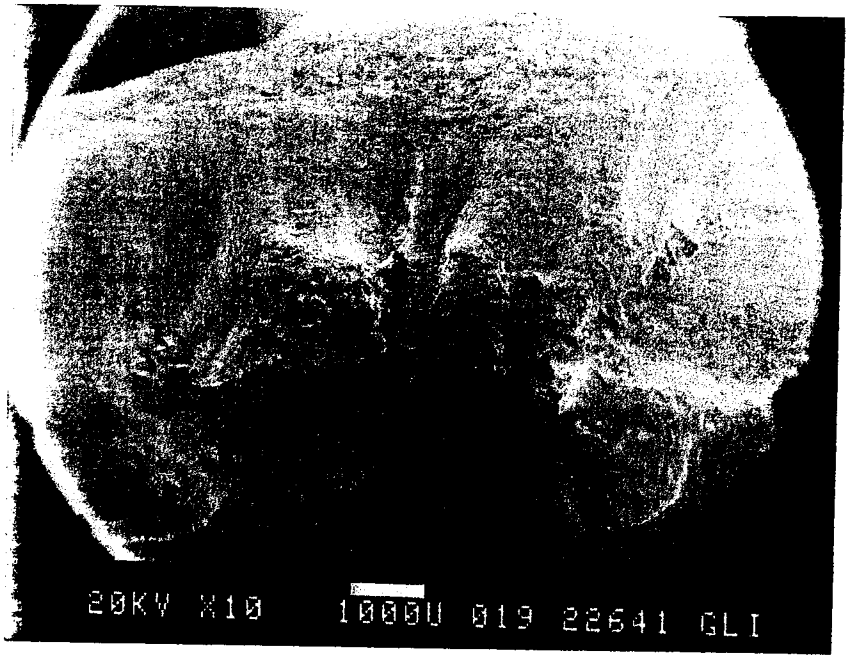


Figure 21. Overview of weld fracture on Sample SEM 3.

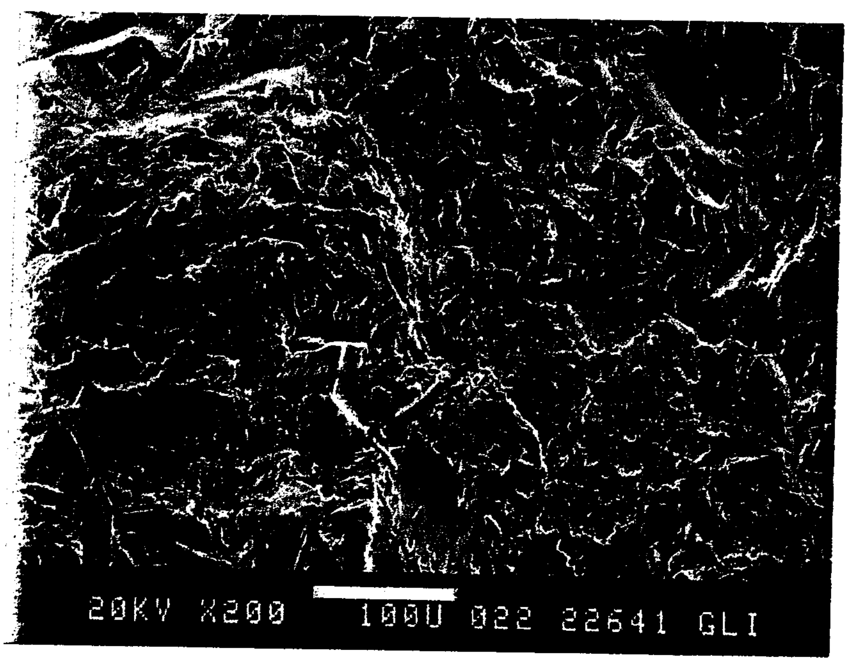


Figure 22. Details of cleavage on fracture face of SEM 3.

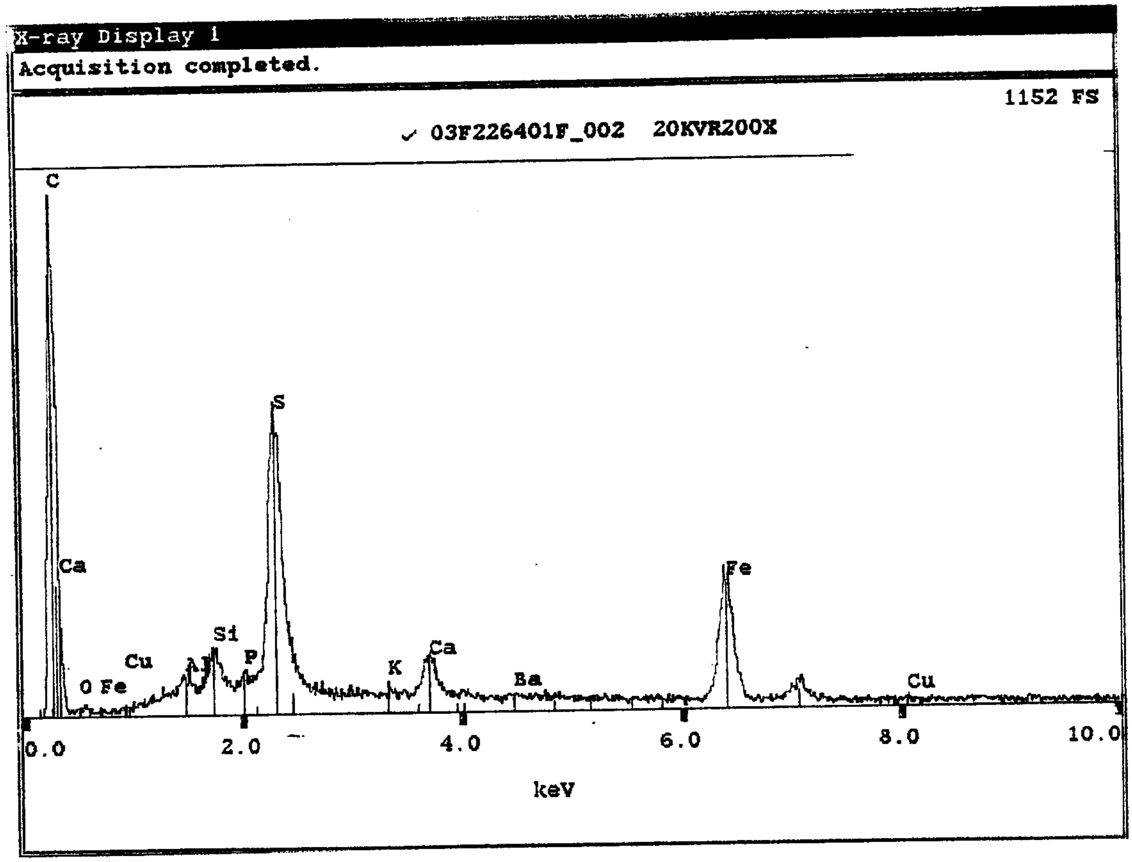


Figure 23. Results of EDS of black deposit/film on flame cut end of pipe.

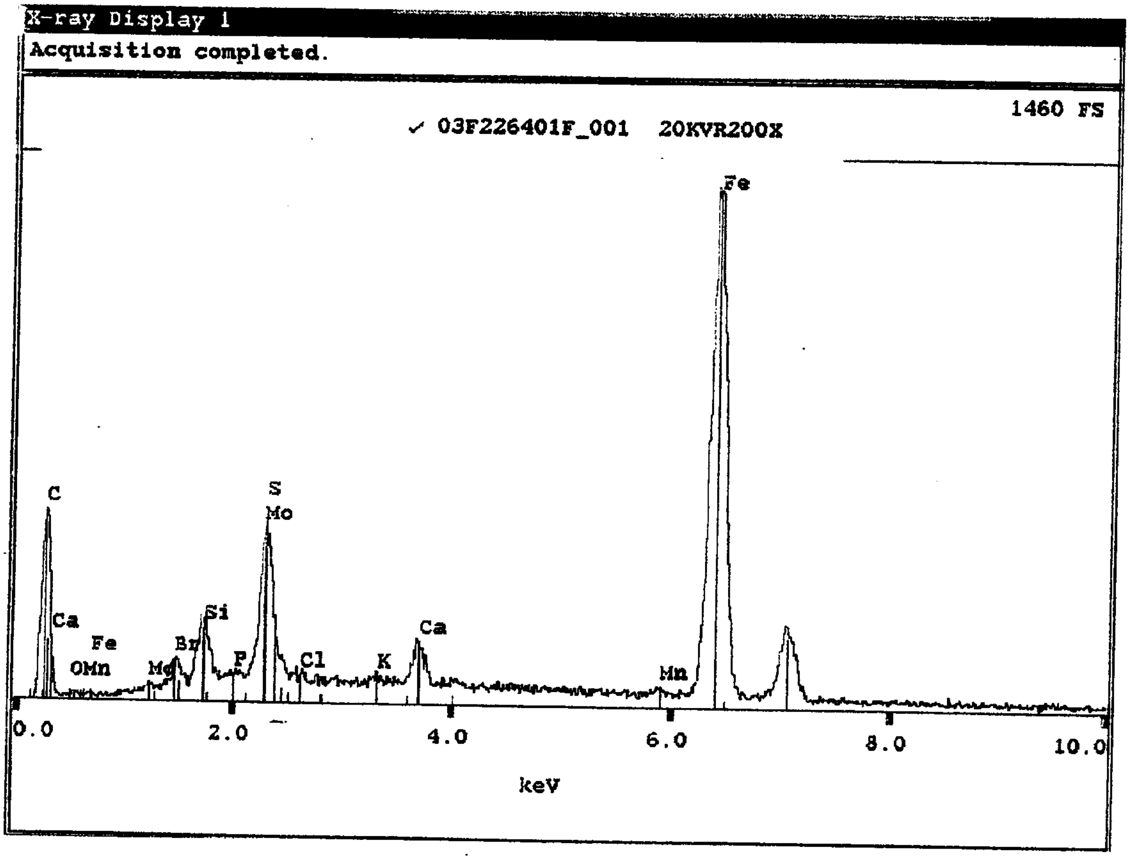


Figure 24. Results of EDS of black deposit/film near inner edge of weld.

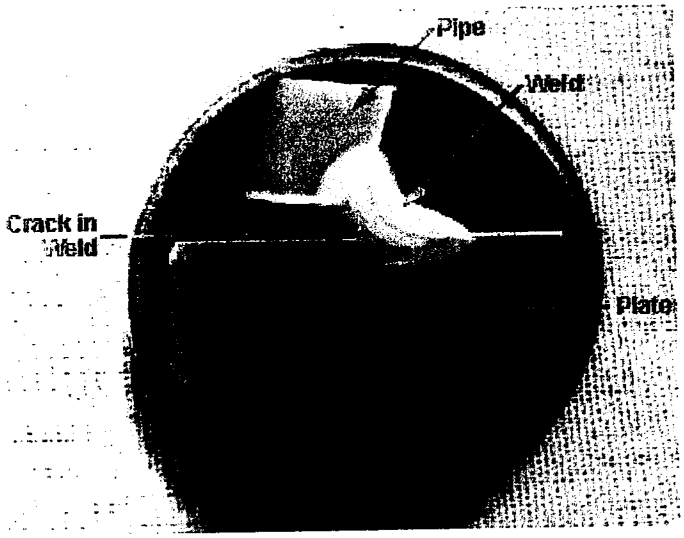


Figure 25. Photomacrograph of Sample MET 0 after polishing and etching.

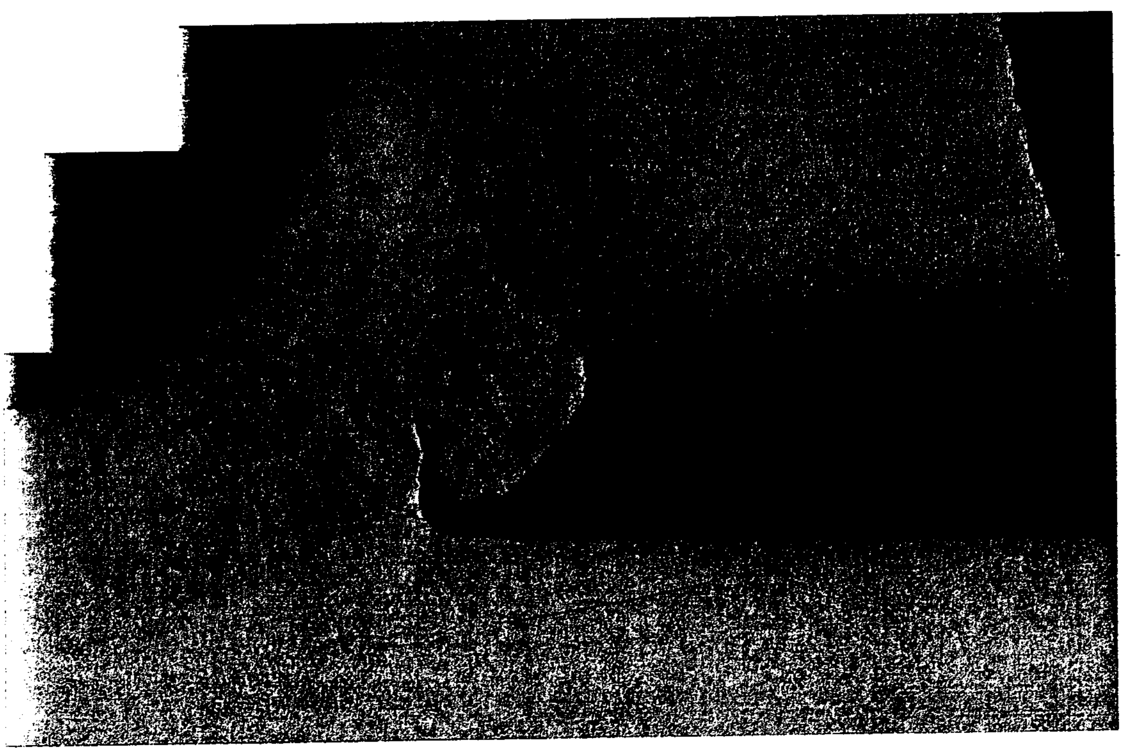


Figure 26. Crack in weld metal of Sample MET 0 (25X).

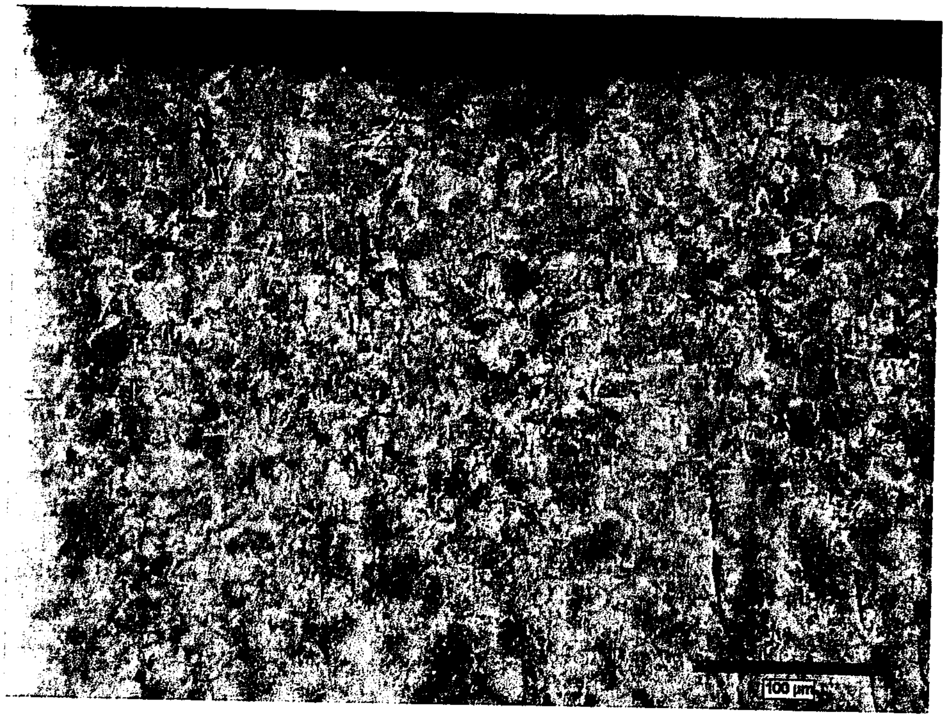


Figure 27. Carburized microstructure near flame-cut end in Sample MET 0.

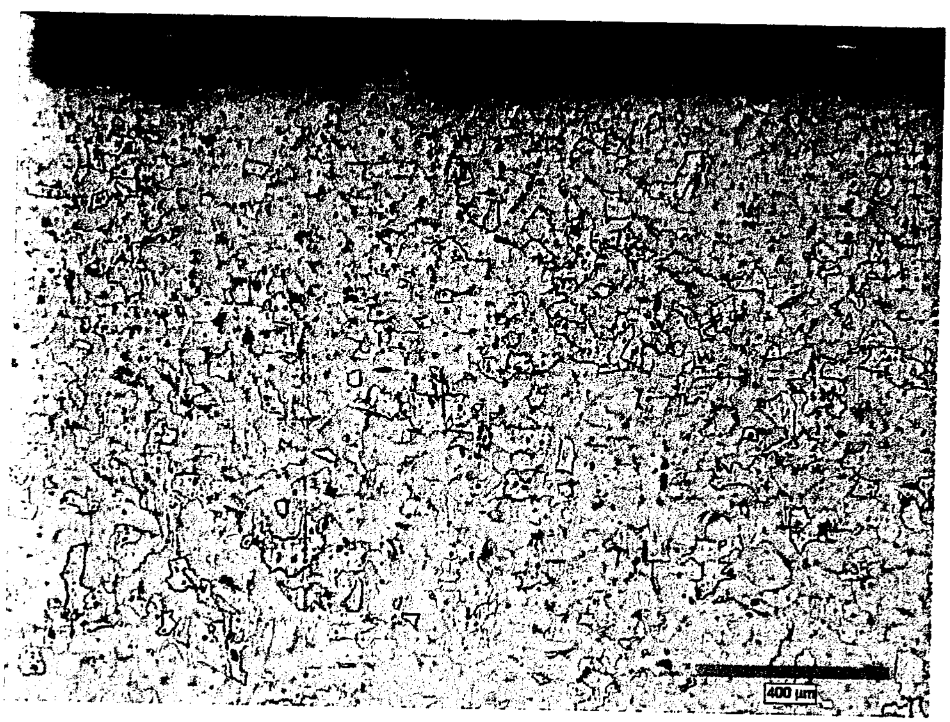


Figure 28. Decarburized microstructure near surface of end plate in Sample MET 0.

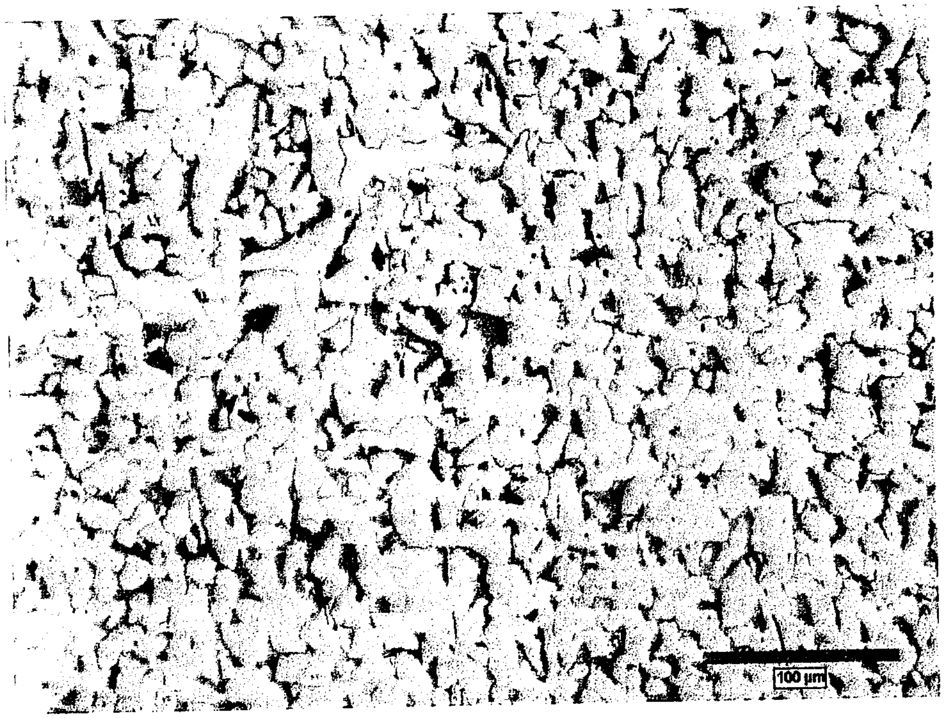


Figure 29. Ferritic-pearlitic microstructure of pipe interior, Sample MET 0.

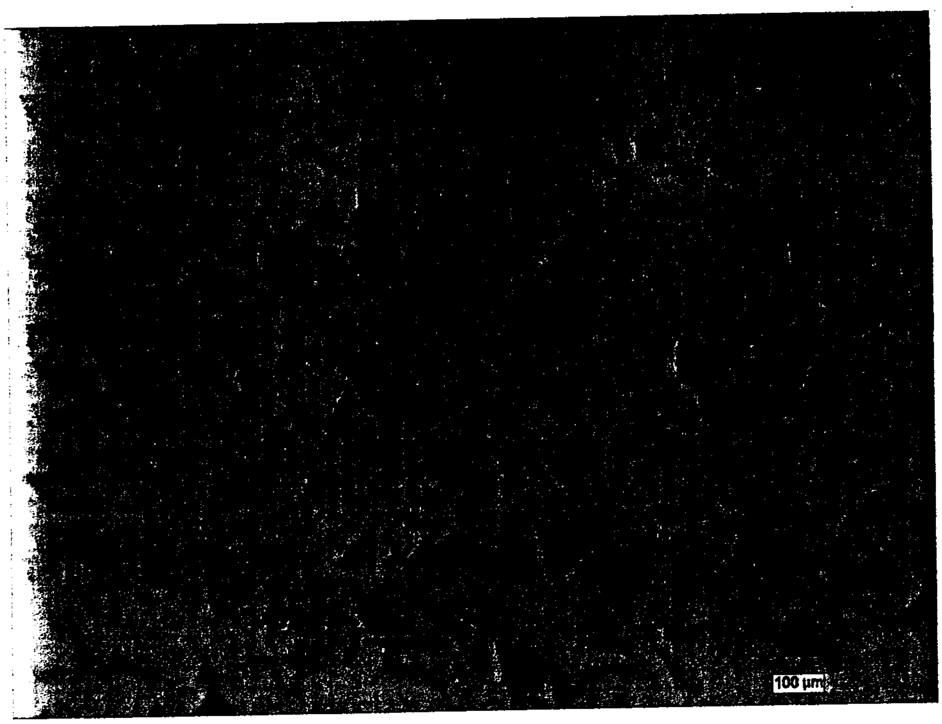


Figure 30. Ferritic-pearlitic microstructure of end-plate interior, Sample MET 0.

Figure 31. Section through low-cycle fatigue fracture near outside surface of weld in Sample MET 1, as polished.

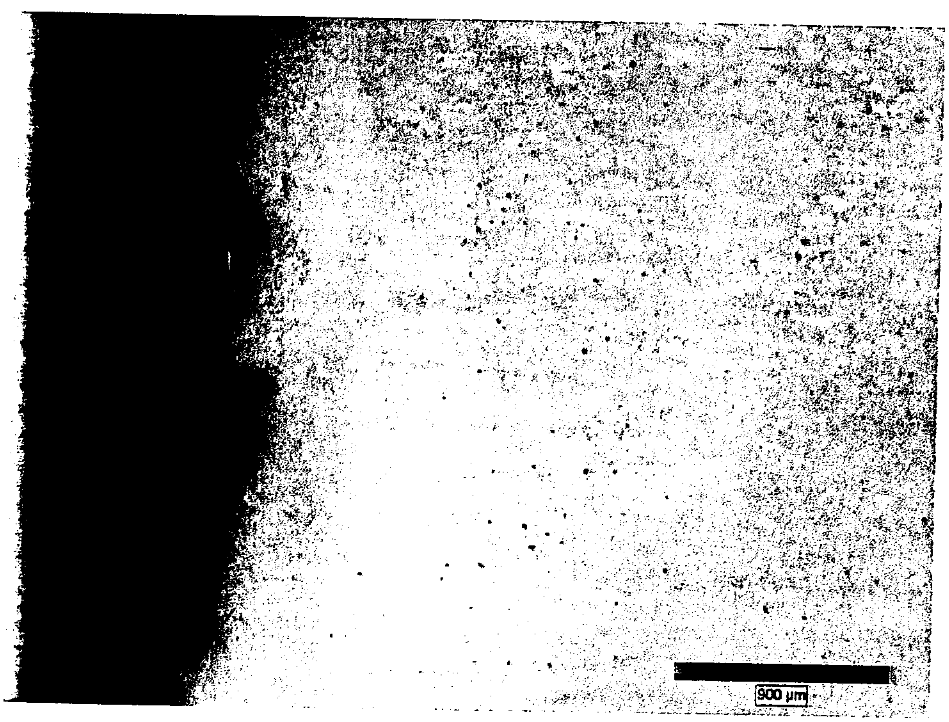


Figure 32. Section through low-cycle fatigue fracture region of weld in Sample MET 2, after etching.

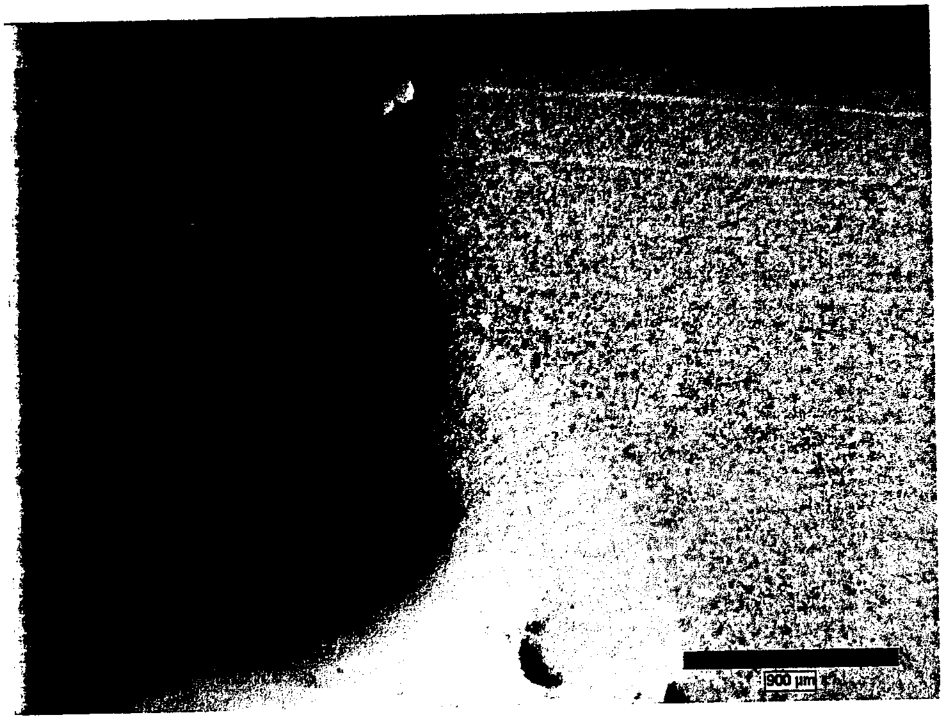


Figure 33. Microstructure near flame-cut pipe end (upper portion) and weld surface (lower portion) of Sample MET 2.

Figure 34. Microstructure along weld surface of Sample MET 2.

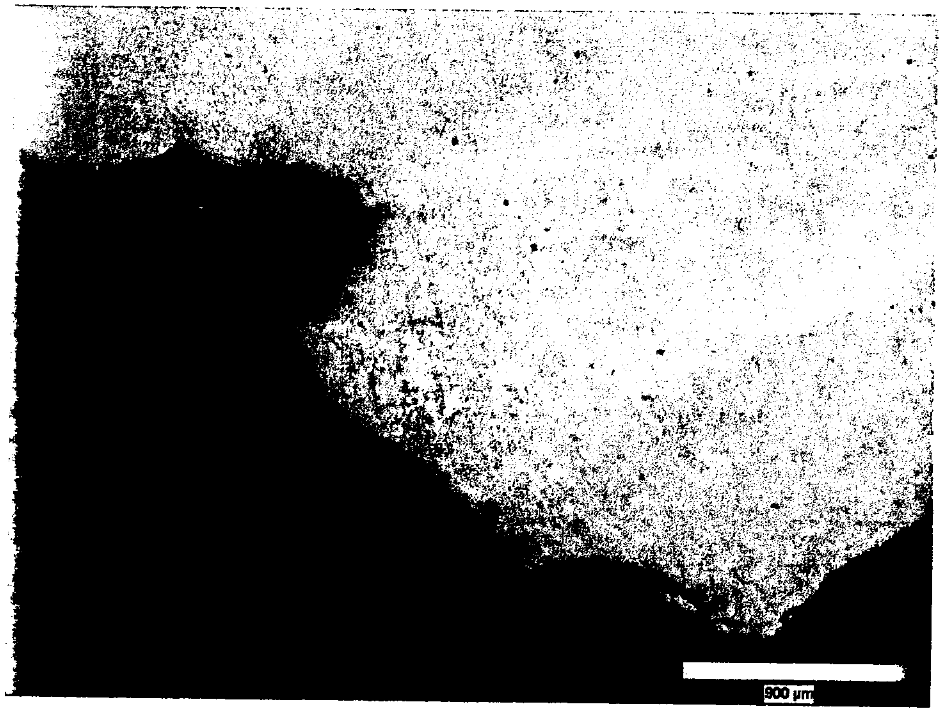


Figure 35. Microstructure along cleavage fracture surface of Sample MET 2.

Memorandum

U.S. Department
of Transportation

Research and
Special Programs
Administration

Central Region Office

Office of Pipeline Safety

Date: February 6, 2002 **Reply to Attn. of:**

Subject: Enbridge Release - Cohasset, MN

From: Ivan Huntoon, Region Director IH

To: Enbridge Accident File - Cohasset, MN

At 10:03 am, on July 4, 2002

James Reynolds called to inform me of a crude oil release from Enbridge in Itasca County near Cohasset, MN. The preliminary information he gave me was as follows:

1) There was a 50 bbl. release.
2) No Public impact.
3) No waterways affected.
4) 34" line

The contact for Enbridge is Mark Sitek @ 888-415-8613. The EPA and FEMA were notified.

At 10:20 am, July 4, 2002

Steve Sweeney of MN-OPS was contacted who indicated that he was not aware of it yet and would look into it further.

At 10:45 am, July 4, 2002

Ron Wiest (Mn-OPS) then called back and indicated that he had left messages and information with Brian Pierizina, and that Brian would be going to the site.

At 3:20 pm, July 4, 2002

Brian called me with more information as he was on-site. The leak occurred in a swamp area. The leak appeared to be contained in a valley about 400 to 500 yards long. It is approximately one (1) mile from the Mississippi River and about one (1) mile from Cohasset, MN.

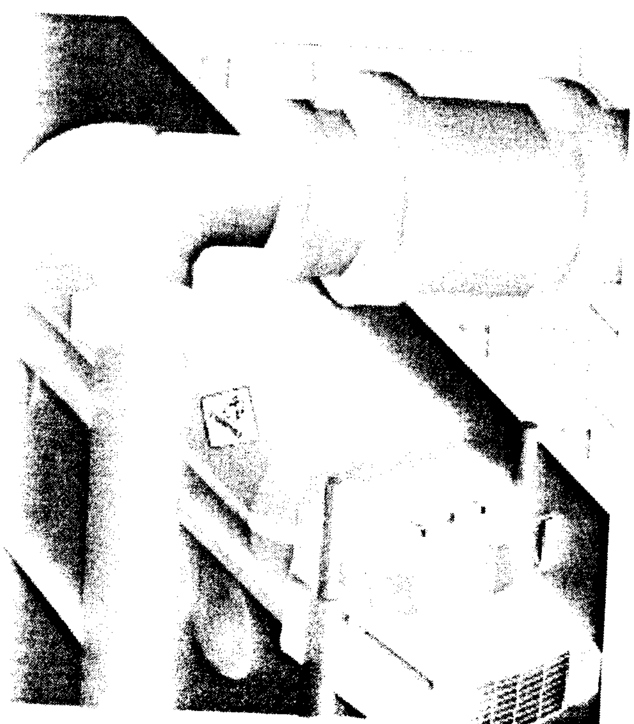
Brian also indicated that the leak was at least 3000 bbls. The pipe was 34". SCADA saw the rupture. There was no spray, so the rupture probably occurred on the bottom of the pipe.

New 36" pipe was just installed in this area back in March 2002. It was 20 to 30 feet away, but not in service yet. The leak is between two hills. Looks like Enbridge will burn off the crude, however, there are overhead power lines that will have to be de-energized before they can start. It looks like it will be a day before they can uncover the pipe.

At 3:50 pm, July 4, 2002

James Reynolds was updated with the new information.

Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota July 4, 2002



Pipeline Accident Report
NTSB/PAR-04/01

PB2004-916501
Notation 7514A

National Transportation Safety Board
Washington, D.C.

Pipeline Accident Report

Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota July 4, 2002

NTSB/PAR-04/01
PB2004-916501
Notation 7514A
Adopted June 23, 2004

National Transportation Safety Board
490 L'Enfant Plaza, S.W.
Washington, D.C. 20594

National Transportation Safety Board. 2004. ***Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 4, 2002.*** **Pipeline Accident Report NTSB/PAR-04/01. Washington, DC.**

Abstract: About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines, LLC ruptured in a marsh west of Cohasset, Minnesota. Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. The cost of the accident was reported to the Research and Special Programs Administration Office of Pipeline Safety to be approximately $5.6 million. No deaths or injuries resulted from the release.

The safety issues identified in this accident are the effectiveness and application of line pipe transportation standards and the adequacy of Federal requirements for pipeline integrity management programs.

As a result of its investigation of this accident, the Safety Board issues safety recommendations to the Research and Special Programs Administration, the American Society of Mechanical Engineers, and the American Petroleum Institute.

Contents

Executive Summary

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines, LLC ruptured in a marsh west of Cohasset, Minnesota. Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. The cost of the accident was reported to the Research and Special Programs Administration Office of Pipeline Safety to be approximately $5.6 million. No deaths or injuries resulted from the release.

The National Transportation Safety Board determines that the probable cause of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

The following safety issues were identified during this investigation:

- The effectiveness and application of line pipe transportation standards.
- The adequacy of Federal requirements for pipeline integrity management programs.

As a result of its investigation of this accident, the Safety Board issues safety recommendations to the Research and Special Programs Administration, the American Society of Mechanical Engineers, and the American Petroleum Institute.

Factual Information

Accident Synopsis

About 2:12 a.m., central daylight time, on July 4, 2002, a 34-inch-diameter steel pipeline owned and operated by Enbridge Pipelines (Lakehead), LLC[1] ruptured in a marsh west of Cohasset, Minnesota. (See figure 1.) Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline as a result of the rupture. No deaths or injuries resulted from the release.

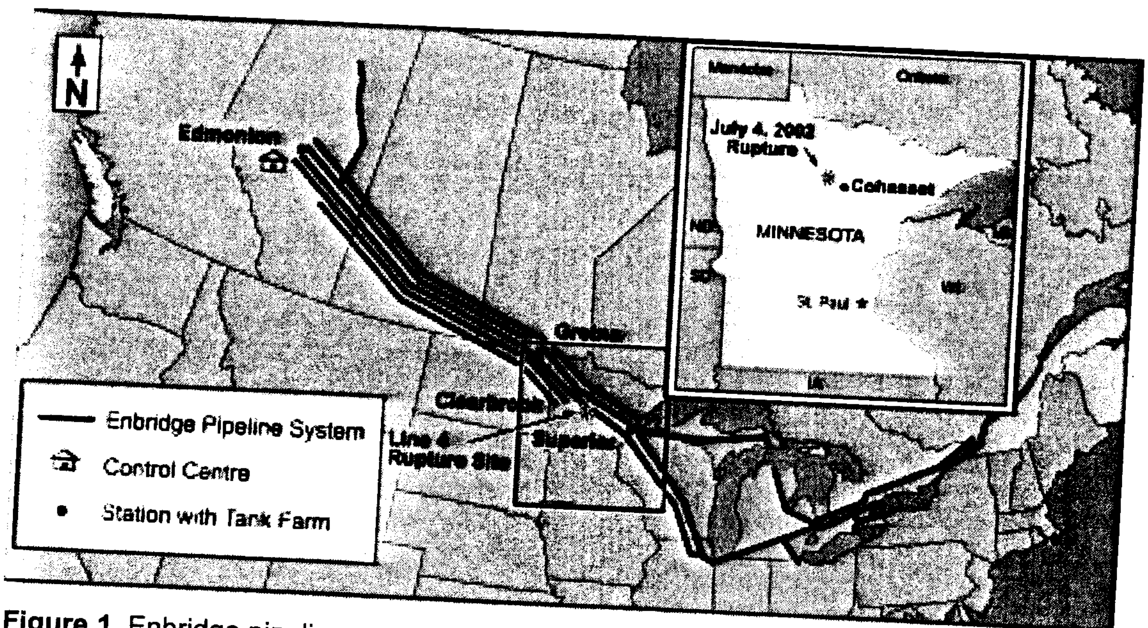


Figure 1. Enbridge pipeline system.

Accident Narrative

The crude oil pipeline involved in the accident originated at Edmonton, Alberta, Canada, and terminated at Superior Terminal in Superior, Wisconsin. The 34-inch-diameter pipeline, designated line no. 4 at the time of the accident, was operated by pipeline controllers in the Enbridge control center in Edmonton using a supervisory control and data acquisition (SCADA) system.[2] About 2:12 a.m. on July 4, 2002, the

[1] Enbridge Pipelines (Lakehead), LLC is the operator of the pipeline system formerly named Lakehead Pipe Line Company.

[2] Pipeline controllers use a computer-based SCADA system to remotely monitor and control movement of oil through pipelines. The system makes it possible to monitor operating parameters critical to pipeline operations, such as flow rates, pressures, equipment status, control valve positions, and alarms indicating abnormal conditions.

controller operating the line observed a SCADA system indication of a loss of suction and discharge pressure at the Deer River pump station. (See figure 2.) At 2:13 a.m., the Floodwood pump station suction pressures began dropping, and then audible and visual alarms were received for an invalid suction pressure. The controller initially suspected an inaccurate pressure transmitter at Floodwood, because the suction pressure had gone to zero. Subsequently, he noticed that the discharge pressure for Floodwood was also dropping and realized that he had an abnormal condition. The controller showed the shift coordinator the situation, and, suspecting a possible leak, they agreed at 2:14 a.m. to shut the pipeline down. At 2:15: a.m., the controller initiated closure of the pipeline injection valve at the Clearbrook Terminal and began shutting down pumps and remotely closed valves to isolate the suspected leak. The upstream valve at Deer River and the downstream sectionalizing valve at milepost (MP) 1017.9 were remotely closed by 2:21 a.m., which isolated the ruptured section. All remotely controlled valves on the pipeline from Clearbrook to Superior Terminal were closed by 2:32 a.m.

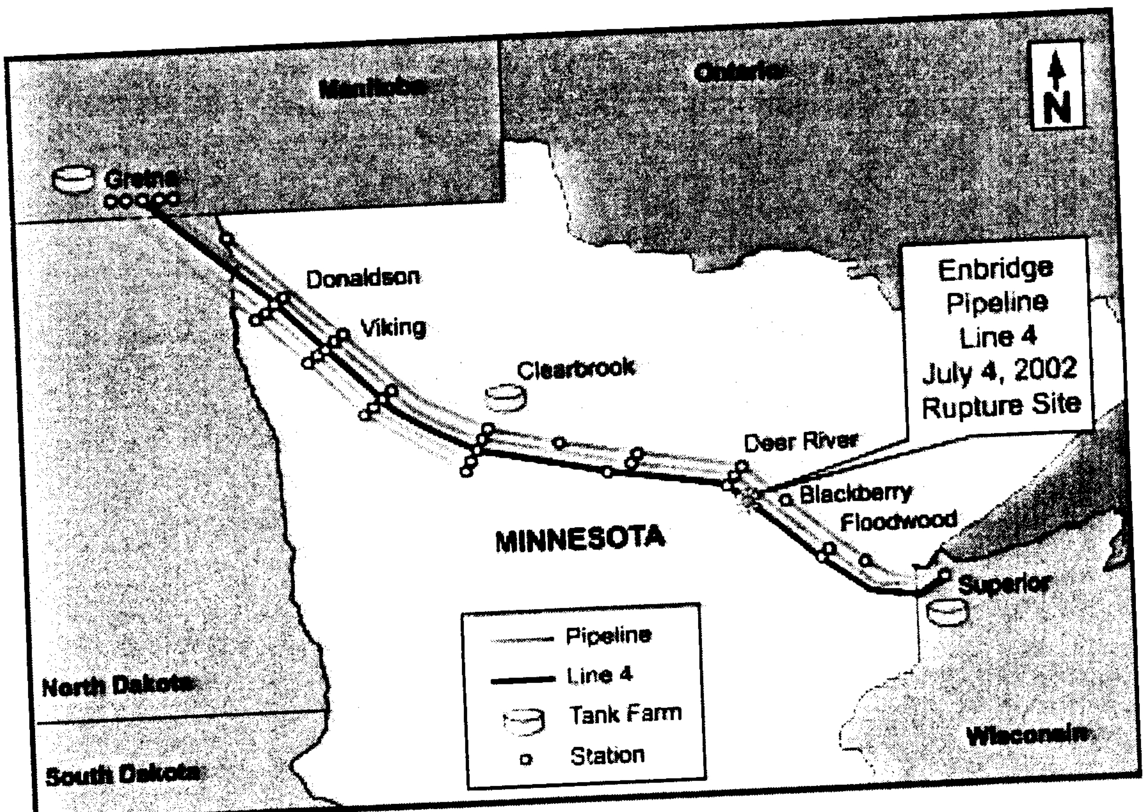


Figure 2. Enbridge pipeline facilities and rupture site.

About 2:25 a.m., the Enbridge control center notified the Deer River and Floodwood police departments of the suspected leak, and about 2:30 a.m., Enbridge field personnel were notified. About 5:20 a.m., Enbridge field personnel dispatched to investigate along the pipeline right-of-way detected the odor of crude oil in a marshy area near Blackwater Creek and manually closed the closest valve to the failure. This valve was near MP 1007.32, about 4 1/2 miles downstream (east) of the rupture.

At 7:00 a.m., after Enbridge field employees verified the release, Enbridge notified the National Response Center of a crude oil leak in the company's 34-inch pipeline. This notification indicated that an unknown amount of crude oil had been released. The pipe was found to have ruptured at MP 1002.73, about 7 miles downstream of the Deer River pump station. The company then contacted local, State, and Federal officials, as well as Enbridge spill response contractors, who proceeded to the spill site. Enbridge also had right-of-way representatives contact landowners in the vicinity of the spill. At 12:09 p.m., Enbridge called the National Response Center again and updated the spill volume to 6,000 barrels of crude oil. At the time of the accident, Enbridge had not designated the area where the rupture occurred as a high-consequence area[3] based on the criteria defined in 49 *Code of Federal Regulations* (CFR) Part 195, "Transportation of Hazardous Liquids by Pipelines."

Emergency Response

Booms were placed in Blackwater Creek as a precaution to prevent crude oil from moving away from the spill site toward nearby waterways, including the Mississippi River. Enbridge started building a 1/4-mile-long road along the right-of-way to the spill site using wood mats. With heavy rain forecast, responders were concerned that the crude oil might spread farther and contaminate the Mississippi River. The unified command for the accident response was established and included the Cohasset Fire Department, Enbridge, the Minnesota Pollution Control Agency, the Minnesota Department of Emergency Management, and the Forestry Division of the Minnesota Department of Natural Resources.

The unified command decided that the best way to prevent the crude from entering nearby waterways was to perform a controlled burn. As a precaution, the command designated 12 homes in the local area to be evacuated, and seven residents were evacuated. Later in the afternoon, the Minnesota Department of Natural Resources coated the spill's perimeter with chemical fire retardant from tanker planes. After the chemical was placed, flares were shot into the crude oil to ignite the oil.

The controlled burn was ignited about 4:45 p.m. (See figure 3.) The burn created a smoke plume about 1 mile high and 5 miles long. (See figure 4.) The controlled burn lasted until about 5:00 p.m. the next day, July 5. While they monitored the fire, Enbridge personnel, firefighters, and environment authorities also monitored the spill perimeter to ensure that no crude was getting into area waterways. Reportedly, no free-flowing product reached any of the boomed areas.

[3] *High-consequence area* refers to commercially navigable waterways, high population areas, concentrated population areas, or unusually sensitive areas that might be affected by an accident involving the pipeline in that area. Title 49 CFR 195.450, 195.452, and 195.6 contain the criteria for designating an area a high-consequence area for hazardous liquid pipelines.

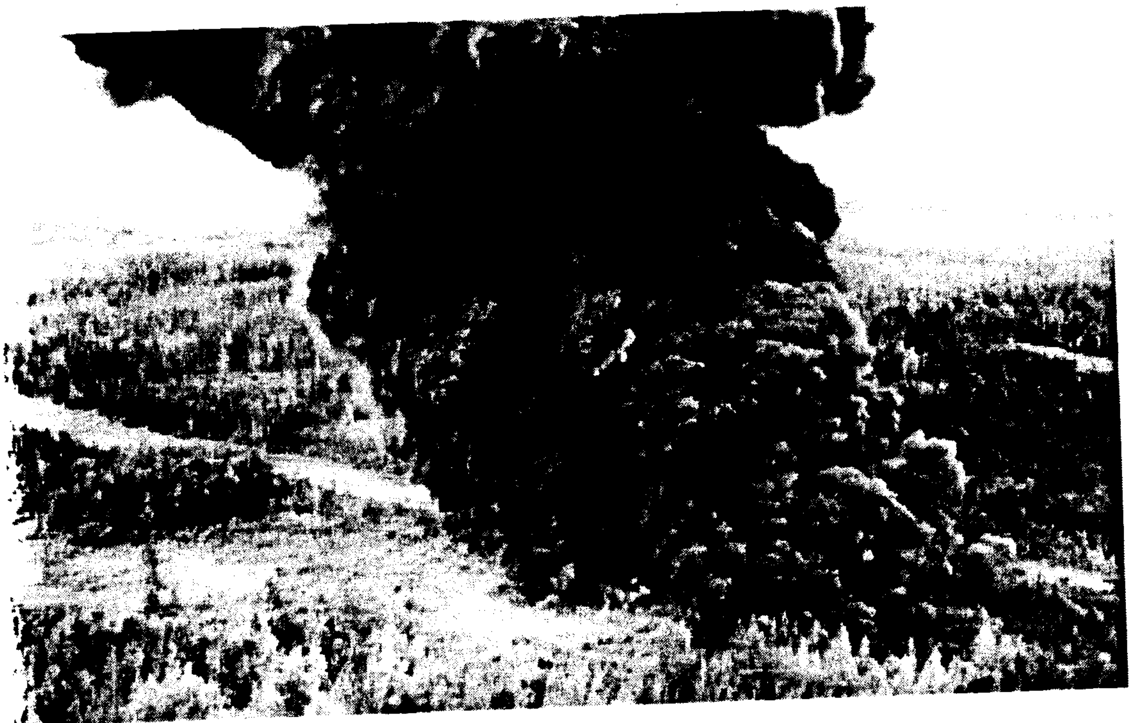


Figure 3. Controlled burn surrounded by white fire retardant.

Figure 4. Smoke plume 1 mile high and 5 miles long.

Damage

The cost of the accident was reported to the Research and Special Programs Administration (RSPA) Office of Pipeline Safety to be approximately $5.6 million.[4] Enbridge recovered 2,574 barrels of oil and estimated that the in situ burn consumed approximately 3,000 barrels, with the remainder being lost to evaporation or entrapment in the soil.

Postaccident Inspection

On July 6, after vacuum trucks had removed the remaining oil and water, the ruptured pipe was exposed. The pipe was fractured along the edge of a longitudinal weld. When the pipe that failed was installed, the longitudinal weld was at the 5:30 clock position when viewed facing downstream (eastward). The rupture was about 69 inches long and gapped open about 6 1/4 inches at the center. (See figure 5.) At the rupture location, the pipeline was rated for a regulatory maximum operating pressure of 687 pounds per square inch, gauge (psig). The pressure at this location at the time of failure was calculated to be 526 psig. The United States Steel Corporation (U.S. Steel) manufactured the pipe at its National Tube Works in McKeesport, Pennsylvania.

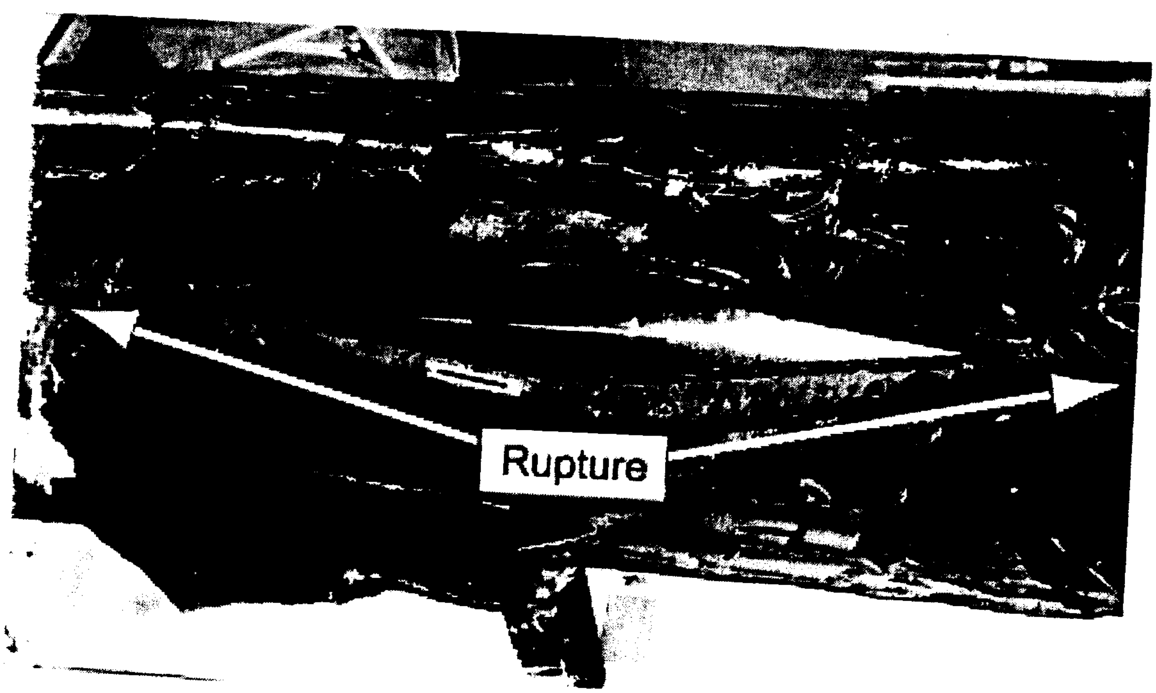


Figure 5. Rupture in accident pipe.

[4] This total includes estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the pipeline operator and others.

Tests and Research

Two sections of pipe, one containing the rupture and one from the same length of pipe, were removed and sent to the Safety Board's Materials Laboratory for metallurgical examination. The pipe that ruptured was manufactured in accordance with American Petroleum Institute (API) standard 5L, grade X52, indicating that the steel had a specified minimum yield strength[5] of 52,000 pounds per square inch (psi). The 34-inch outside diameter pipe was specified as 0.312-inch nominal wall thickness with a double submerged arc weld (DSAW) longitudinal seam weld. The pipe had a diameter-to-wall thickness (D/t) ratio of 109:1. The pipe was coated with a spiral wrap tape that was applied in the field during construction in 1967.

Surface corrosion was visible on the outer surface of the pipe adjacent to the rupture, but no dents, scratches, or gouges were present at any location on the pipe sections examined. The corrosion was assessed as light, with no apparent pitting and little apparent loss of wall thickness. Both pipe sections were ultrasonically inspected for cracks along the longitudinal seam weld, and, other than the rupture that caused the accident, no additional cracks or discontinuities were uncovered. Fatigue cracking[6] has been shown to initiate at seam welds because of changes in geometry, residual stress, and material properties associated with the weld. Metallurgical testing and examination of the ruptured area found no material or manufacturing defect in the steel or the welded seam of the pipe.

Initial examination of the rupture revealed a preexisting fatigue region at the center of the rupture. The fatigue region was 13 inches long adjacent to the inside surface of the pipe and did not extend all the way through the pipe wall. (See figure 6.) More detailed examination showed that the fatigue cracking initiated at multiple locations along the inside surface (see figure 7) at the toe of the longitudinal weld bead. (See figure 8.) Examination of the cleaned fracture surface revealed a darker, more heavily oxidized band adjacent to the inside surface of the pipe that extended the entire length of the fatigue area. The more heavily oxidized portion of the fatigue area penetrated a maximum of about 0.04 inch deep at the center of the rupture. The oxidized band was visible for almost the entire length of the fatigue area. Near its ends, the oxidized portion of the fatigue crack extended about 0.010 inch into the pipe wall. The remainder of the fatigue crack was less oxidized and extended more deeply into the pipe wall over the central 6 inches of the fatigue region. Along approximately 2.5 inches in the central region, the fatigue crack almost penetrated the pipe wall. At its maximum depth, the fatigue crack penetrated through 0.270

[5] *Yield strength* is a measure of the pipe's material strength and is the stress level, expressed in pounds per square inch, at which the material starts to exhibit permanent deformation. Although yield strength is expressed in pounds per square inch, this value is an expression of a pipe material's strength, which is not equivalent to a pipe's internal pressure.

[6] The term *fatigue cracking* is used to describe a progressive cracking of structural material that occurs under repeated loading and may eventually lead to failure. The fatigue crack grows with cyclic loading until the crack reaches a critical length at which the stresses cause it to grow unstably leading to structural failure. Fatigue cracks can initiate at microscopic flaws or weak spots in the material. Once initiated, cracks can grow at stress levels that are quite low in comparison to the material's yield strength.

inch of the 0.297-inch measured wall thickness.[7] Measurement and testing of the pipe showed that it met thickness and strength requirements. The pipe fracture beyond the fatigue crack contained features typical of overstress fracture.

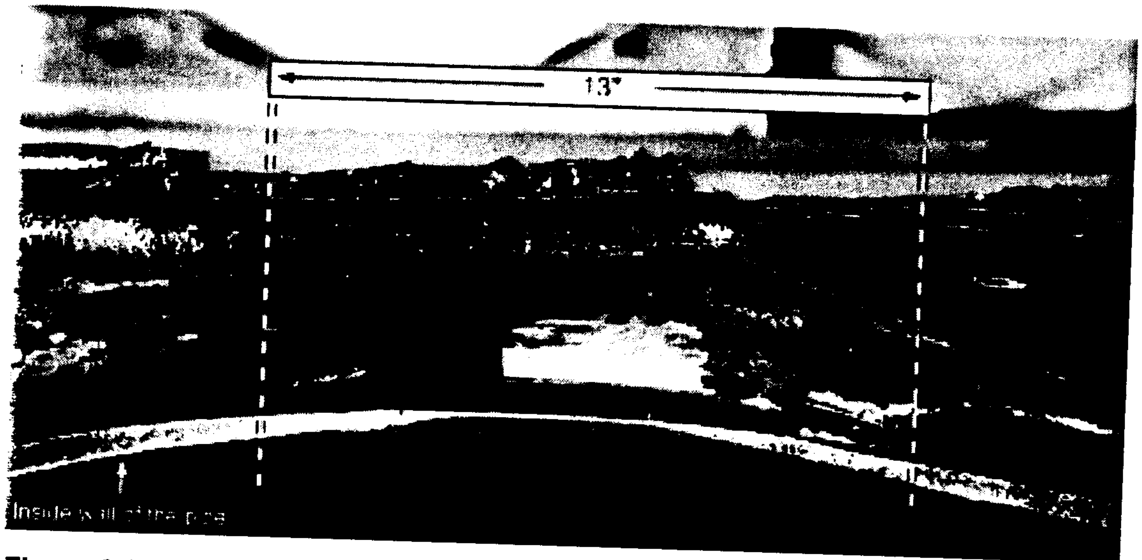


Figure 6. View of top fracture surface of 13-inch-long crack, showing penetration nearly through pipe wall in center.

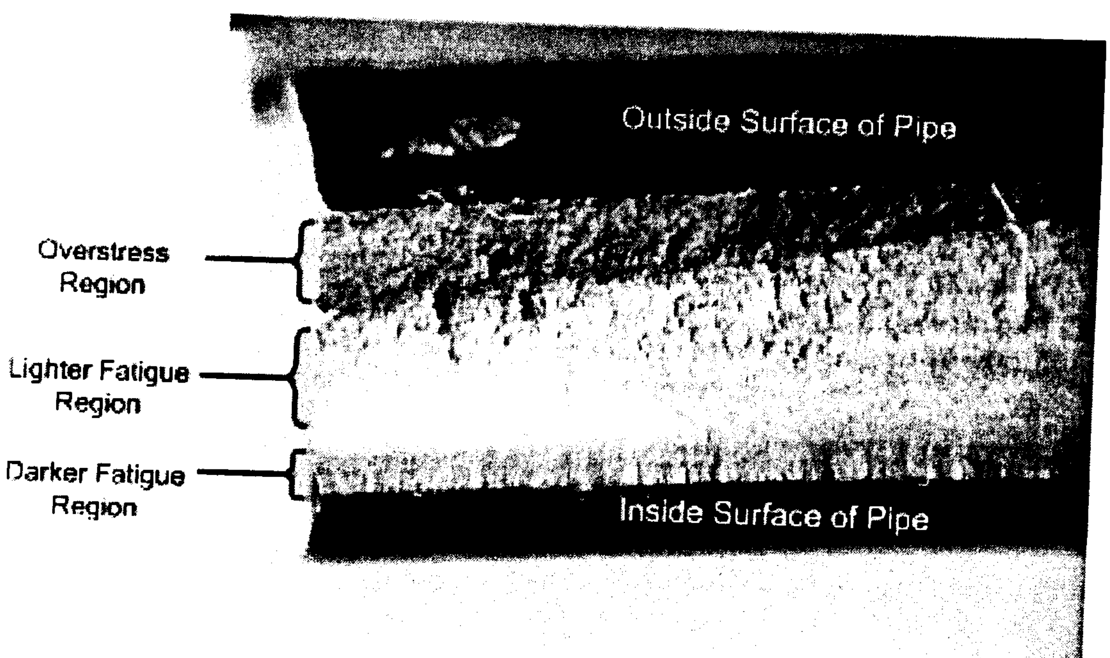


Figure 7. Face of fracture in accident pipe.

[7] The 0.297-inch measured wall thickness is within the allowable range for a pipe with 0.312-inch specified nominal wall thickness.

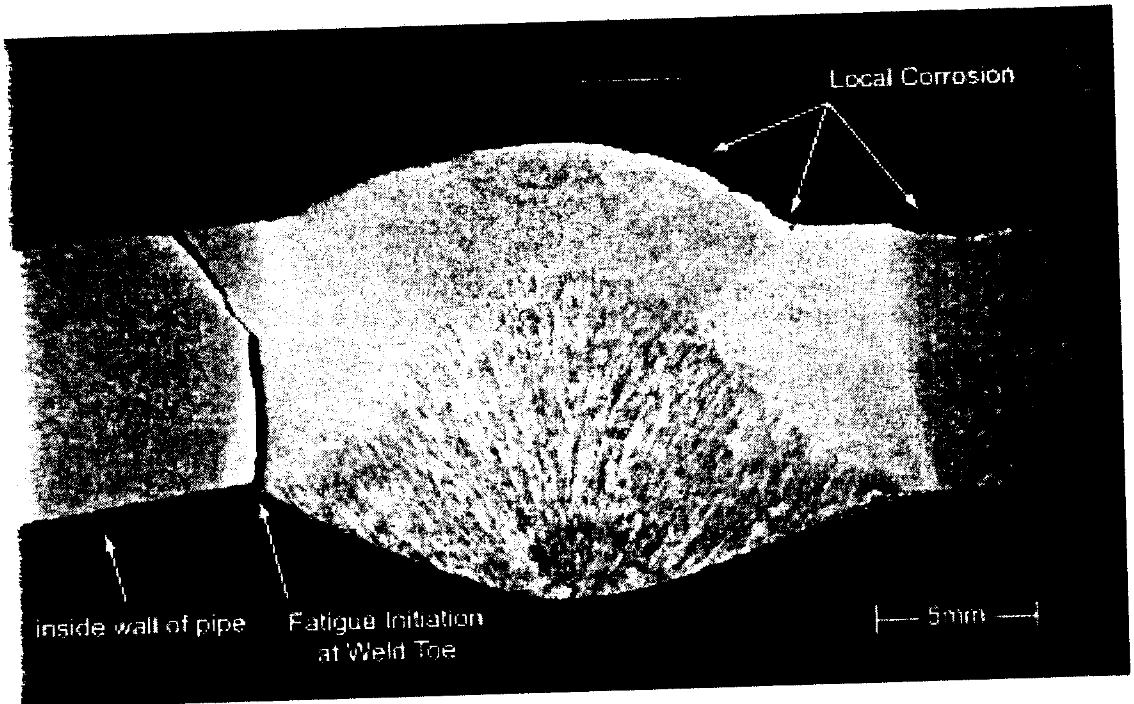


Figure 8. Fatigue initiating at toe of weld on interior surface of pipe.

Preaccident Events

Fatigue Cracking in Enbridge Pipe Manufactured by U.S. Steel

Enbridge's 34-inch U.S. Steel DSAW pipe had a documented history of longitudinal seam weld failures due to fatigue cracks. Metallurgical analysis reports of longitudinal seam weld failures in Enbridge's U.S. Steel pipe in 1974, 1979, 1982, 1986, 1989, and 1991 identified the causes as fatigue cracking at the toe of the weld. Enbridge's 34-inch pipeline system also used A.O. Smith flash-welded pipe, Canadian Phoenix electric resistance welded pipe, and Kaiser Steel submerged arc welded (SAW) pipe. All of the longitudinal seam weld failures caused by fatigue cracks in this pipeline have occurred in pipe manufactured by U.S. Steel.

Operational Reliability Assessments of the Pipeline

After the 1991 pipe rupture at the toe of the weld in the 34-inch pipeline resulted in the release of 40,500 barrels (1,701,000 gallons) of crude oil, Enbridge signed a consent order with RSPA's Office of Pipeline Safety to conduct an operational reliability assessment of the 34-inch pipeline from Gretna, Manitoba, Canada, to Superior, Wisconsin. The assessment was to include a review of pipeline operating conditions and an analysis of the previous pipe failures. The operator was also required to restrict allowable operating pressures, to hydrostatically pressure test[8] the pipeline to establish that the line was safe to operate, and to develop a program to ensure that the line would continue to be safe in the future.

In December 1992, Enbridge performed an operational reliability assessment[9] of the 34-inch pipeline in the United States. As a result of the study, changes were made in pipeline operations that reduced the number of pressure cycles[10] and their associated pressure ranges. Among other actions it took as a result of the 1991 rupture, Enbridge financially and technically supported British Gas's development of the Elastic Wave in-line inspection tool to identify pipe cracks before they precipitate a failure. British Gas did the inspections in 1995 and 1996. PII North American, Inc. (PII), the successor to British Gas, currently provides the inspection tool data report of the Elastic Wave inspection tool in the United States.

The pipeline section in which the 2002 rupture occurred was pressure tested to 835 psig after its construction in 1967. Enbridge's first longitudinal seam weld in-service failure of U.S. Steel pipe from a fatigue crack occurred in July 1974. The entire pipeline, including the pipe joint[11] containing the failure, was pressure tested between 1974 and 1976 at a test pressure of 764 psig. The entire 34-inch pipeline was pressure tested in 1991 and 1992 at higher stress levels than had been used before. Because of variations in pipe wall thickness and changes in elevation in each section of the pipeline, the test pressure range was from 85 percent to 105 percent of the specified minimum yield strength of the pipe, or up to 1,002 psig.[12] The 1991 test pressure at the point of the July 4, 2002, rupture was 937 psig. The operator agreed in 1991 to pressure test the pipeline again in 5 years unless an in-line inspection tool capable of identifying cracks in the longitudinal seam of the pipe was developed. RSPA did not allow the operator to raise the pressures above those in effect at the time of the 1991 accident while the consent order was in effect.

During the 1991 and 1992 pressure testing program, Enbridge found four crack-like/manufacturing defects, four corrosion defects, and one blister. Two subsequent leaks occurred that resulted from pressure-cycle-induced growth of fatigue cracks in U.S. Steel pipe. The two in-service leaks occurred in the first 6 months of 1994 at the site of fatigue cracks that had survived the pressure test levels of the 1991–1992 program. A reassessment report was completed in December 1994 following those two failures. Enbridge's metallurgical report indicated that the initiating fatigue cracks were readily apparent adjacent to the inside pipe wall and had been introduced during the transportation of the pipe, as they were smoother and darker than subsequent fatigue crack growth. The report

[8] A hydrostatic test of a pipeline involves filling the pipeline with water or similar liquid, gradually increasing the pressure of the liquid to a predetermined maximum, and examining the line and/or test records for indications of a leak.

[9] The 1992 assessment was updated in 1994, 1995, and 1998.

[10] One pipeline *pressure cycle* is the pressure variation from a minimum to a maximum pressure and to the minimum again.

[11] A *joint* is a single length of pipe, nominally 40 feet long.

[12] Using the internal design strength formula in 49 CFR Part 195, a test pressure of 954 psig is calculated at 100 percent of specified minimum yield strength for line pipe with the specification of the pipe that ruptured.

noted that both defects at the point of failure showed evidence of having grown during the 1991–1992 pressure tests and concluded that ductile tearing of the metal caused the growth of these existing defects. Another Enbridge conclusion was that the operating histories of the upstream operating stations showed that pressure cycles also contributed to the failures.

After Enbridge ran tests with the Elastic Wave inspection tool, the results were reviewed and recommendations were included in Enbridge's 1995 integrity assessment report. As a result of the recommendations, Enbridge proposed to RSPA an in-line crack inspection program as the most appropriate means of reducing or eliminating the risk of pipeline failures. The detection level specification for the Elastic Wave tool stated that the tool would find a defect equal to or greater than 2.5 inches long with an accuracy of ±0.4 inch at 4.5 mph. The detection level specification for crack depth was 25 percent of the pipe wall thickness with a sizing accuracy of ±25 percent of the wall thickness. For an indication to be reported to the operator as a defect, both the crack length and the crack depth threshold requirements had to be met.

RSPA agreed in 1995 to the use of the in-line crack inspection program in lieu of hydrostatic pressure testing. As a condition for accepting the proposal for 1996, RSPA stipulated that it would review the inspection program before deciding on future pressure testing. One of the reasons for conditional approval in RSPA's stipulations was that RSPA wanted to know whether the Elastic Wave inspection tool would identify not only pipe crack defects that would fail during hydrostatic pressure testing but also considerably smaller defects that could then be repaired or removed before they could grow and lead to failure of the pipe.

In 1995, Enbridge began inspecting its 34-inch pipeline with the Elastic Wave in-line inspection tool and found that the tool was identifying more pipe crack defects than had been identified by previous hydrostatic pressure testing. Twice during 1995 and again in early 1996, PII's tool was used to inspect the pipeline section that contained the crack that ruptured in this accident, but various mechanical problems with the inspection tool resulted in unusable data. PII acquired usable data in a May 1996 inspection. (The details of this inspection are discussed later in this report.)

In the 4 years from 1995 through 1998, 216 miles (66 percent) of the 325 miles of 34-inch pipe from Gretna, Manitoba, to Superior, Wisconsin, had been inspected with the Elastic Wave tool, and pipeline repairs were made according to the pipeline operator's policy. All crack defects identified by the inspections were repaired with pipe sleeves, and none were removed and subjected to metallurgical examination. During this period of time, in-line inspections were performed on all U.S. Steel manufactured DSAW pipe. As a result of these inspections, the operator excavated the pipe at 74 locations. An evaluation concluded that none of the defects found with the Elastic Wave tool would have failed a pressure test to 100 percent specified minimum yield strength. Following completion of the Elastic Wave tool inspections in the 34-inch U.S. Steel pipe, Enbridge submitted an assessment report dated April 28, 1998, that proposed reinspecting the pipeline approximately 10 years from the previous inspection. A number of reviews were made by RSPA before closure of the consent order on May 5, 1999. After the consent order was closed, Enbridge operated the pipeline up to the pressures allowed by 49 CFR Part 195.

Before the accident, Enbridge's unwritten defect inspection practice for Elastic Wave data was to excavate all crack-like indications that were found by the Elastic Wave tool. Enbridge ran Elastic Wave tool inspections in all of its 34-inch pipeline sections in the United States between 1995 and 2001. Based on the results of these inspections, the company excavated 23 crack-like features; 23 weld/manufacturing defects; 16 other defects, including corrosion and laminations; and 41 spurious[13] indications and made repairs where needed.

Elastic Wave In-Line Inspection at Rupture Location

The in-line inspection company, PII, performed a computer analysis of the May 1996 Elastic Wave inspection tool log data as part of its interpretation process after the tool was run. An indication was present at the point where the pipe ruptured on July 4, 2002. PII interpreters reviewed the indication in their initial screening of the data in 1996, but the indication did not exhibit the diamond-shaped signature signifying a crack and did not meet PII's standard that an anomaly must meet at least 6 of 10 feature selection criteria in order to be identified as a crack. After the accident, PII stated that, at most, the indication would have met two of the feature selection criteria. An important feature selection criterion that the indication did not meet was confirmation of the signal from both the clockwise and counterclockwise views as the tool records data while moving downstream through the pipe. PII representatives stated that during the May 1996 inspection run, one of the tool's two sets of wheel sensors was close to the longitudinal weld, which placed the weld in proximity to the source of the tool's ultrasonic signal and could have resulted in the masking of the signal.

PII's postaccident review of the May 1996 data also evaluated the size of the indication at the rupture and determined that it was below the detection level specification for a reportable defect (25 percent of pipe wall thickness and 2.5 inches long). The data on this indication have been recorded in a database, and PII and Enbridge have worked to determine how this information will be used to improve the feature selection criteria. Also after the accident, RSPA had an independent consultant and PII analyze the May 1996 inspection log data for the area from 0.5 mile upstream to 0.5 mile downstream of the rupture location. No indications were found with characteristics similar to those of the July 4, 2002, rupture.

In addition, PII personnel reviewed the log data from two 1995 Elastic Wave tool inspections that had shown no significant defect at the point of the 2002 rupture. They found that on the first run, the clockwise sensor was functioning properly and was not on the longitudinal weld at the point that ruptured. The counterclockwise channel was working but was electronically noisy and provided a weak signal at the point that ruptured. Thus the signal on this run did not meet feature selection criteria for confirmation of the signal from both the clockwise and counterclockwise views. The signal on this run also did not exhibit the diamond-shaped crack signature. On the second 1995 log, the clockwise channel was not providing acceptable quality data when it was in the area of the point of rupture.

[13] *Spurious* features were those that did not have a corresponding defect associated with them, had qualities not considered a defect (for example, weld profile), or were under sleeves and could not be assessed.

All of the 1995–1996 in-line Elastic Wave tool inspections were performed by the Mark II version of the device. In 1997 the tool was upgraded to the Interim Mark III, which contains an additional set of wheel sensors that are offset so at least one set of sensors is not riding on the longitudinal seam weld.

Both before and after the accident, Enbridge provided PII with feedback on its findings from actual excavations and field inspections. This feedback is a part of the continuing development effort on Elastic Wave technology. PII advised the Safety Board that it always requests feedback from its customers on field excavation data to improve accuracy and reliability. However, the amount and quality of feedback for in-line inspection tools varies with each pipeline company.

Pipe Movement

On February 5, 2002, Enbridge detected movement in the 34-inch pipeline in the same marsh where the subsequent July 4 failure occurred. The movement occurred as Enbridge was excavating a ditch for the construction of a parallel 36-inch-diameter pipeline. At this point, the existing and new lines were separated by about 20 feet. As the ditch for the new line was being opened, the peat began to settle down toward the ditch, and the existing 34-inch pipeline began to move laterally toward the ditch. Enbridge workers saw the movement of the line and had the pipeline shut down for evaluation.

The pipeline was found to have moved down and laterally a maximum of 18 inches. The maximum movement had occurred at MP 1002.8 and involved more than 750 feet of pipeline. Enbridge stated that it had calculated the stresses in the pipe caused by the movement and found them to be well within the parameters for movement of an in-service pipeline as specified in API recommended practice RP 1117, *Movement of In-Service Pipelines*. Enbridge continued to monitor the site after the construction of the parallel pipeline and observed that the 34-inch pipeline had returned to within 6 inches of its original position. The return toward the original position was believed to have been caused by the rehydration of the peat.

Railroad Transportation of Thin-Walled Pipe

A 1962 technical paper[14] prepared from research by Battelle Memorial Institute discusses the prevention of pipe stresses that can occur during the transportation, handling, and laying of thin-walled pipe. As noted in the paper, advances in technology and the availability of higher strength materials have led to the widespread use of thinner walled, larger diameter pipe that is more susceptible than thicker walled, smaller diameter pipe to stresses that could be introduced during transportation. The paper states:

[14] Atterbury, A. T., "Stresses During Shipping, Handling and Laying Thin Walled Pipe," *Pipe Line News*, December 1962, pp. 44–47.

> Damage to line pipe during shipment has been confined to a very small number of pipe shipped. This damage has mostly taken the form of local abrasions and dents caused by contact with rivet heads or other protrusions in the rail car or truck. In a few instances, however, leaks have been attributed to fatigue cracks initiated due to cyclic stresses that are induced during shipment. It is possible for these cracks to initiate with no noticeable surface damage to identify them.

The paper goes on to say:

> The stresses developed during shipment (usually most severe during rail shipments because of higher stacks and higher g-loadings) depend on the diameter, thickness, loading configuration, and number of bearing strips. The potential damage done, of course, depends on the number of cycles of stress which are imposed during shipment.

In January 1965, the API addressed the prevention of fatigue cracks initiating during railroad transportation of pipe by publishing a recommended practice, API RP 5L1, *Railroad Transportation of Line Pipe*. API RP 5L1, which applied to 24-inch- to 42-inch-diameter pipe, included recommendations on the design of bearing strips, banding, separator strips, and longitudinal weld placement during pipe loading. The weld was to be placed at the point of least stress during loading, approximately 45° from the vertical (clock positions 1:30, 4:30, 7:30, or 10:30) and not in contact with adjacent pipes. Subsequently, API's April 1972 revision of RP 5L1 expanded the applicability of the recommended practice to include a range of diameters, 2 3/8 inches and larger, and specified that it applied to pipe having a D/t ratio of 70:1 and larger.

The hazardous liquids pipeline safety regulations in 49 CFR Part 195 do not contain requirements that address railroad transportation or any transportation of pipe. The natural gas pipeline safety regulation contained in 49 CFR 192.65, "Transportation of Pipe," which became effective on November 12, 1970, states:

> In a pipeline to be operated at a hoop stress of 20 percent or more of the specified minimum yield strength, no operator may use pipe having an outside diameter-to-wall thickness ratio of 70 to one, or more, that is transported by railroad unless the transportation was performed in accordance with API RP 5L1.

When the natural gas pipeline safety regulations became effective, pipeline operators were prohibited from using an estimated $13 million of stockpiled pipe because operators were unable to verify that the pipe, which had been transported by railroad, was transported in accordance with API RP 5L1. On February 14, 1973, RSPA amended section 192.65 of the natural gas pipeline safety regulations with paragraph (b) of the regulation, which allowed pipe meeting the above criteria that was transported before November 12, 1970, to be installed in pipelines if the pipe was pressure tested to certain requirements detailed in the section.

Colonial Pipeline Company also has experienced ruptures in its 32- and 36-inch liquid pipelines that its metallurgical report attributed to fatigue cracking in U.S. Steel manufactured pipe. Two Colonial 36-inch (D/t ratio 128:1) pipeline fatigue crack ruptures in U.S. Steel pipe transported by railroad occurred in Greenville County near Spartanburg, South Carolina, on May 13, 1979, and June 16, 1979. The May rupture released 136,000 gallons of fuel oil that damaged vegetation and killed fish. The June rupture released 395,000 gallons of fuel oil that damaged vegetation and killed wildlife and fish.

In 1980, the Safety Board investigated an accident involving a 32-inch-diameter U.S. Steel pipe (D/t ratio 114:1) in a Colonial Pipeline Company pipeline near Manassas, Virginia, in which 92,000 gallons of fuel oil leaked from a fatigue crack that was initiated during rail shipment of the pipe.[15] The rupture damaged vegetation and killed approximately 5,000 fish and some waterfowl and small animals. At the time, hydrostatic pressure testing was the only method available for finding crack defects; however, the accident report noted that hydrostatic pressure testing is inadequate because the test itself may cause small cracks to propagate without causing them to fail during the test.

As a result of its investigations of the 1980 accident, the Safety Board issued Safety Recommendations P-81-13 and P-81-14 to RSPA:

> P-81-13
>
> Expedite, in cooperation with the American Petroleum Institute and the American Gas Association, the jointly sponsored program to determine the extent of pipe failures in existing pipeline systems with a diameter-to-thickness ratio of 70 or greater due to fatigue cracks initiated during the rail shipment of the pipe.
>
> P-81-14
>
> If it is determined that pipe failures in existing pipeline systems with a diameter-to-thickness ratio of 70 or greater due to fatigue cracks initiated during the rail shipment of the pipe are a continuing problem, develop operating and testing guidelines to assist pipeline operators in minimizing pipe failures.

RSPA responded that the Materials Transportation Board had reviewed the extent and seriousness of a series of pipeline failures due to fatigue cracking that developed during rail transportation. As a result of the review, seven failures were found that were attributable to fatigue cracking due to railroad transportation. RSPA responded that it considered this a limited problem that did not require regulatory action at that time but that the agency would continue to monitor failures for any indications of future problems. Safety Recommendation P-81-13 was classified "Closed–Acceptable Action" on February 23, 1982. Safety Recommendation P-81-14 was classified "Closed–No Longer Applicable" on March 21, 1983.

[15] National Transportation Safety Board, *Colonial Pipeline Company Petroleum Products Pipeline Failures, Manassas and Locust Grove, Virginia, March 6, 1980*, Pipeline Accident Report NTSB/PAR-81/2 (Washington, DC: NTSB, 1981).

On December 18, 1989, another fatigue crack failure occurred on Colonial's 32-inch pipeline in U.S. Steel pipe. As a result of the 1989 failure, RSPA's Office of Pipeline Safety created a task force to study Colonial pipeline failures attributable to fatigue cracking. U.S. Steel, Kaiser Steel, A.O. Smith, Bethlehem Steel, and Republic Steel manufactured the pipe involved in the study, and the pipelines were constructed between 1962 and 1964. Of these manufacturers' pipes, all had a submerged arc weld in the longitudinal seam except the A.O. Smith pipe, which had a flash-welded longitudinal welded seam. The RSPA task force concluded in its September 14, 1990, report that six Colonial pipeline failures from 1970 through 1989 resulted from fatigue cracking that was probably initiated during rail transportation of the pipe. The task force report stated that five fatigue crack failures were found in U.S. Steel pipe and that one was found in Republic Steel pipe. The report stated that crack growth by fatigue is a greater possibility in liquid lines than in gas lines because liquid lines are subjected to frequent and substantial cycles of pressure variations during normal operations.

The RSPA task force report describes the loading method tests that Battelle Laboratories conducted in 1962 under contract from Colonial Pipeline Company. Battelle reported that the susceptibility to fatigue cracking during rail transportation increases for pipe with larger D/t ratios because such pipe is more susceptible both to static stresses from the weight of the pipe and to cyclic stresses during transportation. RSPA's report also noted that the American Gas Association conducted research to develop solutions to transportation fatigue and found that the higher the D/t ratios, the more susceptible the pipe to fatigue crack initiation. The American Gas Association research concluded that pipe with a D/t ratio greater than 70:1 has a possibility of fatigue crack initiation and requires special care in railcar loading. RSPA's 1990 task force report stated that with the implementation of API RP 5L1 in 1965, the occurrence of railroad transportation cracks had been virtually eliminated.

A 1988 paper[16] documented numerous transit fatigue crack failures that occurred during initial hydrostatic pressure testing of the pipe. The types of pipe included DSAW, electric resistance weld, and seamless steel pipe that had been shipped by rail or marine vessels. In nine fatigue failures that occurred between 1969 and 1982, the pipe had been transported by railroad and the diameters ranged from nominal 6-inch to 20-inch pipe with D/t ratios from 42:1 to 64:1. In 17 fatigue failures that occurred between 1976 and 1987, the pipe had been transported by marine vessel and ranged from 6 inches to 24 inches in diameter with D/t ratios from 28:1 to 85:1. The paper stated:

> Transit fatigue results from cyclic stresses induced by gravitational and inertial forces. The weight of a load of pipe imposes a steady stress of a given magnitude. As the load moves up and down, the pipe flexes, inducing alternating tension and compression at both the inside and outside surfaces. The alternating stresses initiate cracks.

[16] Bruno, T.V., "Transit Fatigue of Tubular Goods," *Pipe Line Industry*, July 1988, pp. 31–34. (This paper is also referenced in the foreword of the sixth edition of API RP 5L1, July 2002.)

The D/t ratios that could lead to fatigue cracking during transportation were changed in the 1990 edition of API RP 5L1. The ratio was reduced from 70:1 to 50:1 because fatigue cracking had been reported in pipe with D/t ratios lower than 70:1. The latest edition of API RP 5L1, issued in July 2002, also states that pipe with D/t ratios well below 50:1 may suffer fatigue in transit under some circumstances.

No statistics on transportation damage were specifically tracked before RSPA instituted a change in 2002 to gather more detailed accident statistics. However, RSPA is now gathering information on whether an accident is caused by pipe damage sustained during transportation and whether the failure is a longitudinal tear or crack.

Railroad Transportation of Accident Pipe

The section of pipeline where the rupture occurred was constructed in 1967. The Enbridge 1966 purchase specification for the pipe included a requirement that pipe loading details be provided subject to its approval. In its quotation, U.S. Steel provided a diagram for railroad car loading (see figure 9), which Enbridge subsequently approved. The railcar loading instructions consisted of a drawing with notes specifying the blocking supports and banding to be used under and around the pipe and the required positioning of the longitudinal weld. U.S. Steel also noted in its specifications that the purchaser would spot-check railcar loadings at the mill before transportation. U.S. Steel transported the pipe by railcar to its storage facility near the mill, where it was unloaded and stored. Later, U.S. Steel loaded the pipe for transportation by rail. Finally, the pipe was loaded on trucks for transportation to the construction sites.[17] Enbridge had arranged with Moody Engineering Company (Moody) to inspect the manufacturing of the pipe. The handling and loading of the pipe for transportation from the mill to storage was a part of that inspection. These activities were summarized in Moody's final report. The Moody report indicates that the pipe was periodically inspected at a nearby storage facility to ensure that the pipe was being handled and unloaded with care. The report indicates that the pipe was accepted for shipment subject to the operator's shipping instructions. U.S. Steel did not document inspections of pipe loading. No records were found to indicate that the engineering company or the pipeline operator inspected the loading of the pipe on railroad cars for transportation from the U.S. Steel storage facility.

[17] Records related to the production activities at U.S. Steel's McKeesport pipe mill were destroyed several years ago after the mill was closed for a period of time.

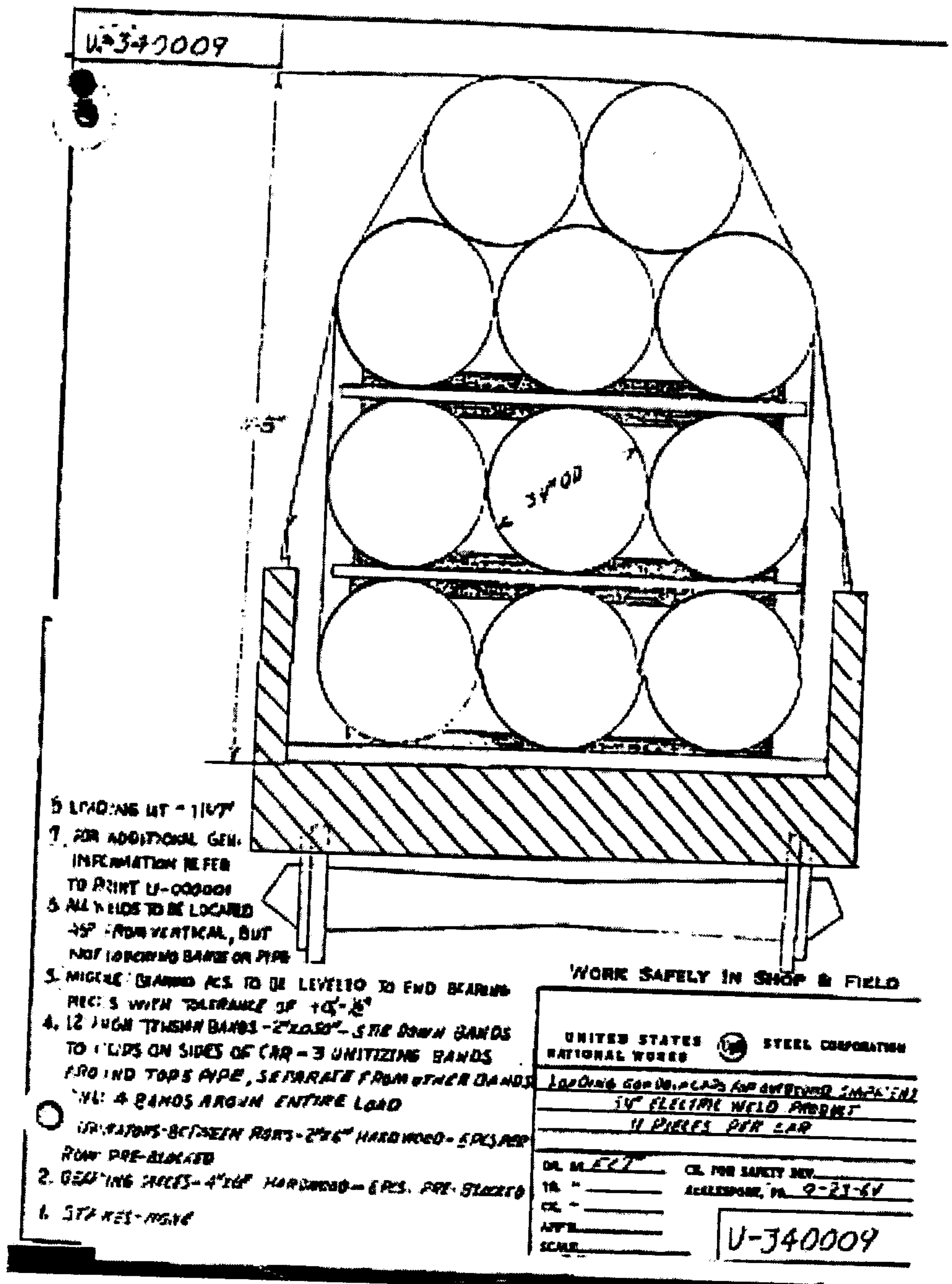


Figure 9. U.S. Steel loading diagram for railcars.

The U.S. Steel employees who had loaded the 1966 DSAW pipe order could no longer be found. According to a former shipping department employee (who was not present at the time of the Enbridge pipe loading), a typical pipe loading practice before and after this pipe order was to position the longitudinal weld at the 2, 4, 8, or 10 o'clock position so the pipe weld would not touch lumber, bands, or other pipe. If a 40-foot joint of pipe was not loaded in this position, it was to be rotated as necessary to attain one of these positions. Except for the loading diagram, there were no written procedures for loading pipe, nor did U.S. Steel use checklists or other methods to confirm that the pipe was loaded according to specifications.

U.S. Steel does not currently manufacture DSAW or SAW pipe. U.S. Steel Tubular Products does produce seamless and electric resistance weld pipe, and the current loading procedures for the pipe are described in the company's *Pack, Mark, and Load Manual.* The procedures to be used for each order are entered into the order entry system from the purchase order and are designated on the mill order sent to the production mill. All pipe manufactured to API standards and destined for railroad transportation from the pipe mill is to be loaded to the requirements of the Association of American Railroads' *Open Top Loading Rules Manual*[18] and the supplementary recommended practices in API RP 5L1. Any additional transportation requirements are referenced in the mill order for the shipping department personnel and, if applicable, are attached to the mill order. A preproduction meeting is held at the mill to review the order and shipment requirements.

At pipe mills currently producing tubular products for U.S. Steel, shipping department workers are trained in the department's standard operating procedures. The group leader in the loading area discusses the loading requirements for each order with the crew. A load tally sheet is created that shows the length of each pipe joint with the referenced heat number for the material. The yard foreman checks the railcars periodically to confirm that the pipe is loaded according to the written requirements.

Before 1991, Enbridge specified that the manner of loading pipe for rail transportation should be provided in the pipe manufacturer's quotation, which was subject to Enbridge's approval. Currently Enbridge includes the use of API RP 5L1 in its specification for purchase of pipe transported by rail from a pipe mill. Enbridge also inspects the pipe during loading at the pipe mill to confirm that the requirements of API RP 5L1 are being met.

Safety Board Materials Laboratory Study

The Safety Board performed a finite element study of the U.S. Steel loading practice to determine the static stresses in pipe loaded for rail transportation. The study showed that the peak circumferential tensile stresses would have been highly localized to the areas in contact with the bearing and separator strips and that the stresses would have occurred at the inner surface of the pipe.

The length of the fatigue crack in this accident was similar to the length over which the peak circumferential tensile stress was predicted in the finite element model, and the fatigue crack initiated at the inner surface of the pipe. The finite element model

[18] The Association of American Railroads' *Open Top Loading Rules Manual* includes Section 1, General Rules Manual for Loading all Commodities, and Section 2, Loading Metal Products Including Pipe.

indicated that the circumferential tensile stresses decreased rapidly away from the bearing or separator strips. Aligning the welded seams at 45° to the vertical results in very small levels of circumferential tensile stress at the welds during transport. (See figure 10.) The results of the finite element model also indicate that aligning the welds at the 2, 4, 8, or 10 o'clock positions instead of exactly 45° from vertical does not increase the stress levels significantly.

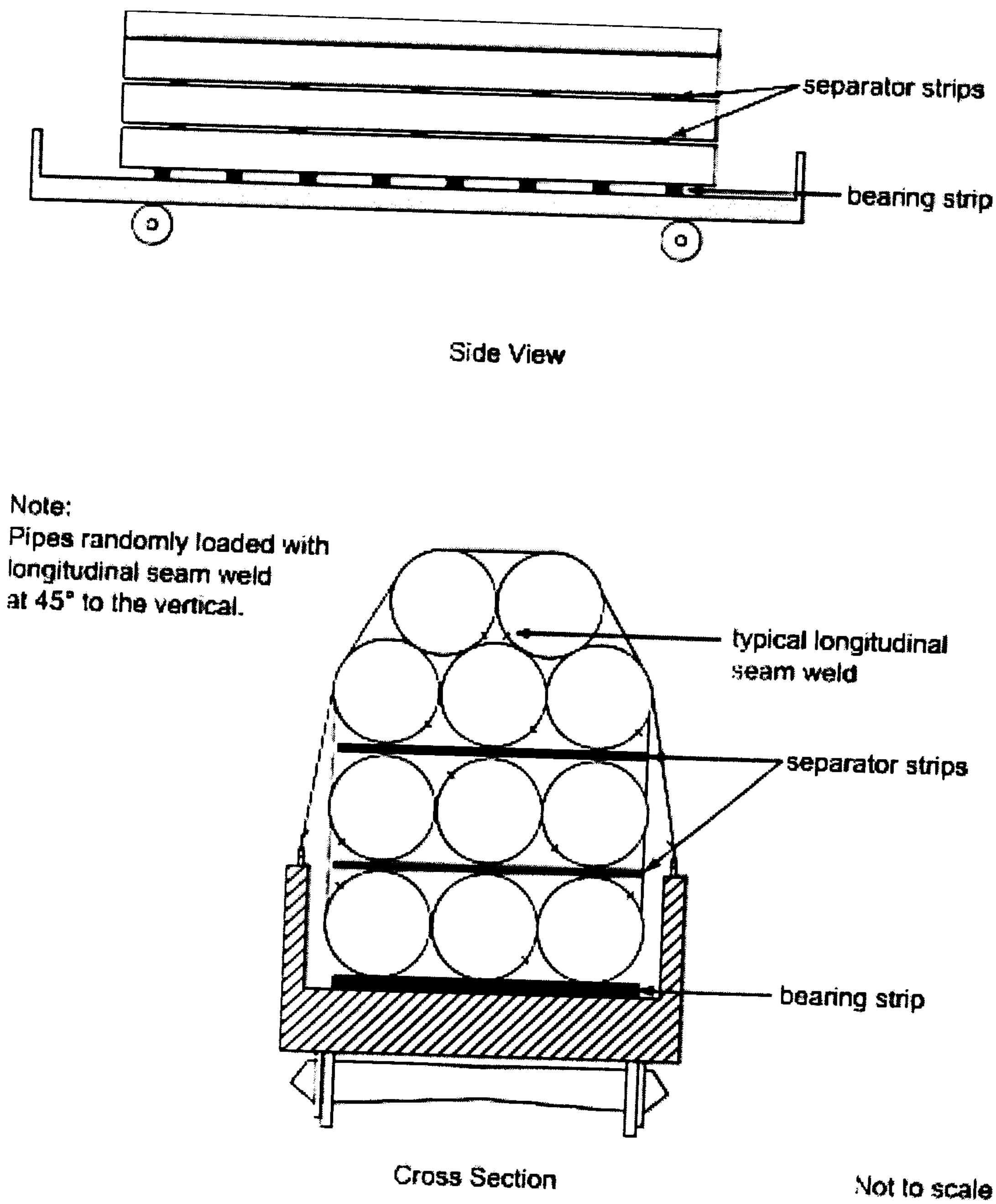


Figure 10. Typical pipe configuration on railroad car.

The Safety Board also studied API loading practices for rail transportation to determine the static stresses in pipe loaded for transportation. API RP 5L1 provides an equation for calculating the peak circumferential tensile stress in a pipe at a bearing strip as a function of the geometry of the loading. API RP 5L1 does not indicate the source of the equation. The purpose of this equation is to calculate the number of flat bearing strips needed to keep the stress below a specified level. The stress determined from the finite element model was compared to the stress calculated by the equation from API RP 5L1 under the same conditions. For a 40-foot-long, 34-inch-diameter, 0.300-inch-wall thickness pipe, the comparison indicates that the equation from API RP 5L1 underestimates the peak circumferential tensile stress by a factor of approximately 2.

The API has also published guidelines for loading pipe for transport onboard marine vessels, API RP 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*. API RP 5LW also includes an equation for calculating the peak circumferential tensile stress in a stack of pipe supported by bearing strips. However, this equation differs significantly from the API RP 5L1 equation, and no source is given for the equation. The stress determined from the finite element model was also compared to the stress calculated by the equation from API RP 5LW under the same conditions. For a 40-foot-long, 34-inch-diameter, 0.300-inch-wall thickness pipe, the comparison indicates that the equation from API RP 5LW also underestimates the peak circumferential tensile stress by a factor of approximately 2.

The Safety Board also evaluated the pipe movement attributed to the nearby excavation on February 5, 2002. The pipeline moved down and laterally a maximum of 18 inches. The deflection of the pipe led primarily to longitudinal tension and compression stresses that would not have affected the fatigue crack (oriented on a plane radially outward along the welded seam). Circumferential tensile stresses and shear stresses associated with the pipe deflection were calculated to be in the range of 1 to 10 psi in comparison to the circumferential tensile stress of 29,750 psi caused by the internal pressure of the oil in the pipe at the time of the rupture.

RSPA Postaccident Corrective Action Order

On July 5, 2002, RSPA issued to Enbridge a corrective action order that required the pipeline operator to conduct a detailed metallurgical analysis of the July 4 failure to determine the cause and contributing factors. The corrective action order also prohibited Enbridge from operating the pipeline until it had submitted a return-to-service plan, which was to incorporate a program to verify the integrity of the 34-inch pipeline from the Deer River Pump Station to Superior Terminal. The plan was to include, if relevant, an in-line inspection survey using a technologically appropriate tool capable of assessing the type of failure that had occurred, including the detection of longitudinal cracks, and remedial action. If relevant, the return-to-service plan was to include an evaluation of the pipeline coating system, a hydrostatic pressure test of the line segment, and a review of all available pipeline data and records.

Enbridge submitted its return-to-service plan to RSPA on July 8, 2002. On July 9, RSPA allowed the pipeline to be restarted with pressure restrictions.

On July 11, RSPA amended the corrective action order to include an operating pressure restriction on pipeline segments between the U.S./Canadian border and Superior Terminal that contained any U.S. Steel pipe. The amended order required that pump station pressure discharges be no higher than 80 percent of the pressure in the line at the time of rupture and that line pressure at the failure site not exceed 80 percent of the pressure at the time of rupture.

On December 2, RSPA permitted Enbridge to raise pressures at pump stations on the Gretna to Clearbrook section of pipe from 80 percent of discharge pressures at the time of the July 4 accident to 80 percent of the highest discharge pressure reached within 30 days of the accident. On June 5, 2003, RSPA allowed the operation of Viking Station, which did not have pump units installed on the 34-inch line at the time of the accident.

Enbridge Postaccident Actions

Before the accident, the area where the pipeline ruptured was not designated a high-consequence area. According to the 2000 census, the population in the area had increased enough to make it a high-consequence area. Enbridge's data on the crude oil released in this area were also used in the 2002 evaluation of Enbridge's high-consequence area pipeline segment identification program. The amount of crude oil released did not trigger the addition of the Cohasset segment as a high-consequence area. In May 2003, as a result of the population change only, the pipeline segment containing the rupture site was classified as a high-consequence area.

Enbridge had begun using a more technologically advanced in-line crack inspection tool, the UltraScan CD, in Canada in 1997. The company ran the tool for the first time in the 34-inch line in the United States in 2001. The detection level specification for the tool states that it will find a defect equal to or greater than 2.50 inches long with an accuracy of ±0.2 inch at 4.5 mph. The detection level specification for crack depth is 0.040 inch with accuracy of ±0.040 inch. Both the crack length and crack depth thresholds must be met for the indication to be reported to the operator as a defect. Since the accident, Enbridge has developed and documented a methodology for determining the need for an investigative excavation from the data obtained from an UltraScan CD. Enbridge also has prepared a pipeline inspection procedure, "Excavation Program for Crack Feature Assessment," as guidance for personnel performing field excavations based on data from the UltraScan CD. The new policy calls for the excavation of all crack-like indications unless an engineering assessment determines that either the indication is acceptable based on a fitness-for-purpose calculation or the indication is not a crack.

Enbridge had reviewed its in-line inspection program and updated it to run the UltraScan CD tool from Gretna, Manitoba, Canada, to Clearbrook, Minnesota, in 2001 and from Clearbrook to Deer River in 2003. The UltraScan CD tool inspected the pipeline section from Gretna to Clearbrook in July 2001, about 1 year before the accident. The data interpretation was completed in September 2002, about 2 months after the accident. No new crack-like indications[19] were reported in the longitudinal seam weld of this pipeline section by the in-line inspection. One notch-like feature[20] identified in a segment of U.S. Steel pipe was excavated and found to be in the middle of a weld cap. Enbridge determined that the feature was an external weld shrinkage crack that was not likely to be related to transportation fatigue. A second notch-like feature was classified as a low-priority feature to be excavated in the future. Other indications were inspected, and no longitudinal cracks were found in any of the field inspections.

Enbridge representatives told the Safety Board that, in addition to excavating all crack-like indications reported by the UltraScan CD tool, the company currently excavates for field examination all notch-like indications in U.S. Steel pipe that are reported at the longitudinal weld to determine whether they are cracks. Currently, the UltraScan CD in-line inspection report does not include a depth estimate for notch-like indications. PII is working with Enbridge to develop a depth estimate of notch-like indications for future inspections. The UltraScan CD inspection tool was run from Clearbrook, Minnesota, to Superior, Wisconsin, in November 2002, and in February 2003 the analysis of the indications found in U.S. Steel pipe was completed. Interim reports allowed for an earlier start of the excavation program for the highest priority indications. The UltraScan CD tool reported 285 defect indications in 121 pipe joints that Enbridge excavated, inspected, and assessed by nondestructive test methods.

Included in these defect indications were 6 crack-like and 29 notch-like indications that were either adjacent to or in the longitudinal weld on U.S. Steel pipe. Enbridge has excavated the 6 crack-like indications and 4 of the 29 notch-like indications to visually inspect and examine the pipe by nondestructive means. The field examination of five of the crack-like indications showed that three were stress corrosion cracking,[21] and two were at the toe of the longitudinal weld. The sixth crack-like indication was found to be a sharp weld contour. One notch-like indication was a defect that was found to have a 42-percent-depth wall thickness crack. Two notch-like indications were an internal gouge and a weld profile (a higher than normal weld cap) feature. The final notch-like indication that was examined was a low-priority feature that was found to be an external shrinkage crack in the center of a weld. The remaining 25 notch-like indications near or in the longitudinal weld were classified as low priority. Enbridge plans to excavate these notch-like indications. Stress corrosion cracking was also found by the UltraScan CD tool and reported as crack-field[22] indications.

---

[19] In PII terminology, a *crack-like indication* is one that is interpreted from UltraScan inspection data as a crack, which is typically at or in the longitudinal weld.

[20] *Notch-like* defects are grooves in the toe of the DSAW longitudinal seam weld, manufacturing defects in flash-welded or electric resistance welded longitudinal seam welds, weld trimming tool marks adjacent to the longitudinal seam weld, or handling marks made during transportation or construction. Although not interpreted to be crack-like features, depending on their characteristics, these indications may need to be considered for excavation because field inspection may reveal them to be cracks.

[21] *Stress corrosion cracking* is the formation of cracks, typically in a colony or cluster, as a result of the interaction of tensile stress, a corrosive environment, and a susceptible material. A colony of very short, axially aligned cracks seen in the field is the typical result of such cracking.

[22] In PII terminology, *crack-field* refers to a crack interpreted as stress corrosion cracking.

The UltraScan CD tool found all internal cracks, now under pipe sleeve repairs, that were previously found by the Elastic Wave tool. No new internal crack-like indications were reported by the UltraScan CD tool under the sleeves, nor were any found during nondestructive field examination of the pipe.

During the field excavations, Enbridge found 21 additional external weld toe cracks on U.S. Steel pipe that were not reported by the inspection tool. According to the field examinations, all 21 of the cracks were below the detection limit specification of the tool. The field information gathered from the entire excavation program will help PII evaluate defect parameters. Of the 285 indications, approximately 60 reported by the tool had field-verified features that were below the contracted threshold limit of the tool for depth, length, or both.

The UltraScan CD tool was designed to detect even smaller defects with a higher degree of reliability than the Elastic Wave tool. Enbridge had an analysis performed that established ranges of key input parameters for predicting reinspection intervals. Using the knowledge learned from the July 2002 failure, Enbridge had crack growth rates for a variety of defect sizes. The most conservative (worst-case) scenario evaluated was a defect 0.080 inch deep by 7.5 inches long, two times the depth and three times the detection threshold of the UltraScan CD tool. This defect has a predicted time until failure of approximately 6.5 years. Enbridge has proposed to RSPA that an alternative to hydrostatic pressure testing is reinspecting the Clearbrook to Superior section of the 34-inch pipeline within 3 years of the previous in-line crack tool inspection.

Enbridge currently has a program to evaluate and repair stress corrosion cracking when it is found in the pipeline. Enbridge has provided field feedback to PII on the UltraScan CD tool data gathered from Gretna to Superior on stress corrosion cracking in the pipe. Enbridge also has asked PII to recalibrate the UltraScan CD tool data using Enbridge's field information to improve the accuracy of stress corrosion crack depth estimates. In addition, a metal loss in-line inspection was completed from the U.S./Canadian border to Superior, Wisconsin.

As a result of these in-line inspections, Enbridge has stated that repairs have been made according to company procedures to all defects that were excavated and examined.

American Society of Mechanical Engineers Pipeline Codes

American Society of Mechanical Engineers (ASME) code B31.8, 2003 edition, *Gas Transmission and Distribution Piping Systems*, section 816, contains guidance on transporting pipe in accordance with the API railroad or marine vessel recommended practices:[23]

[23] API RP 5L5, *Transportation of Line Pipe on Barges and Marine Vessels*, was created in 1975 and later was designated API RP 5LW.

> Any pipe having an outer-diameter-to-wall thickness ratio of 70 to 1 or more, that is to be used in a pipeline at a hoop stress of 20 percent or more of the specified minimum yield strength that has been or will be transported by railroad, inland waterway, or by marine transportation, must have been or shall be loaded in accordance with API RP 5L1 or API RP 5LW, respectively. When it is not possible to establish that pipe was transported in accordance with the appropriate practice, the pipe must be hydrostatically tested for at least 2 hours to at least 1.25 times the maximum allowable pressure if installed in a Class 1 location, or at least 1.5 times the maximum allowable pressure if installed in a Class 2, 3, or 4 location.

ASME B31.4, 1998 edition, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, states: "When applicable, railroad transportation of pipe shall meet the requirements of API RP 5L1."

Analysis

A metallurgical examination of the failed pipe segment of Enbridge's 34-inch-diameter crude oil pipeline indicated that the rupture had occurred at a fatigue crack along a longitudinal seam weld. Hydrostatic pressure testing and an in-line inspection tool specifically designed to find cracks did not detect the crack before failure.

In its investigation of this accident, the Safety Board attempted to determine how and when the initial fatigue crack occurred and to assess methods used to detect cracking in older pipelines before it propagates to pipe failure. The investigation identified the following safety issues:

- The effectiveness and application of line pipe transportation standards.
- The adequacy of Federal requirements for pipeline integrity management programs.

The Accident

The Enbridge Control Center SCADA system's first indication of a release on line no. 4 was dropping suction and discharge pressures at the Deer River station at 2:12 a.m. on July 4, 2002. Subsequently, the Floodwood station suction pressures began dropping, and the controller realized that he had an abnormal condition and suspected a leak. At 2:13 a.m., the pipeline controller called for the shift coordinator, and at 2:14 a.m., about 2 minutes after the rupture, they decided to shut the line down. Within 3 minutes of this decision, all pumps were shut off, and the valves had begun to close. About 4 minutes later, the final closure of remotely controlled valves at Deer River and the remotely controlled valve at MP 1017.9 isolated the ruptured section from the remainder of the pipeline.

About 2:25 a.m., the Deer River and Floodwood police departments were notified of the suspected leak, and at 2:30 a.m. the responsible Enbridge regional personnel were notified. The control center then began analyzing the SCADA data to locate the leak and estimate the volume of the release. The Safety Board concludes that Enbridge's pipeline control center personnel responded in a timely manner to the indications of a pipeline leak.

Transportation of Accident Pipe

At the time Enbridge purchased the pipe that ruptured in this accident, the pipeline industry was aware that thin-wall, large-diameter pipe (such as the 109:1 D/t ratio pipe that ruptured in this accident) was particularly susceptible to cyclic stresses encountered during transportation, especially by rail, and that such stresses could lead to the initiation of fatigue cracking in the pipe unless the pipe was properly loaded and transported. Welded areas were also known to be the areas most susceptible to fatigue crack initiation during transportation.

To address concerns about pipe stress during transportation, Enbridge had required in its purchase specification that pipe loading details be provided subject to its approval. U.S. Steel submitted a diagram with specifications for rail car loading that was designed to protect the pipe, and Enbridge approved it. Enbridge retained an engineering company to inspect the manufacturing, handling, and loading of the pipe by U.S. Steel at the mill and the subsequent unloading at its storage site near the mill. The engineering firm's final report indicated that the pipe was accepted at the storage site for shipment subject to Enbridge's instructions. Final transportation of the pipe was done later from storage, with the pipe traveling by both rail and truck.

The U.S. Steel loading diagram for the railroad shipment that included the accident pipe provided for leveling bearing strips and placing separator strips for support of the pipe, orienting longitudinal welds at 45° to the vertical, and avoiding contact with adjacent pipes. The U.S. Steel diagram was similar to the loading specifications for railroad transportation of line pipe in the January 1965 edition of API RP 5L1. As noted previously, this recommended practice addressed loading pipe to minimize stresses across the longitudinal welded seams of pipe, which are susceptible to fatigue cracking. The Safety Board's review determined that the provisions in the U.S. Steel loading diagram for rail transportation satisfied the requirements of the January 1965 edition of API RP 5L1.

The metallurgical testing and examination of the fatigue crack and ruptured area of the accident pipe found no material or manufacturing defect in the steel or in the welded longitudinal seam. In the absence of manufacturing or material defects, the creation of a fatigue crack would be unlikely to result from normal operational pressure cycles. However, once a fatigue crack has been created it may grow with the repetitive stresses from normal operational pressure cycles.

The fracture surfaces of the fatigue crack in the accident pipe had multiple arrest lines and other indications of progressive cracking starting from the inside surface of the pipe wall. There were two regions paralleling the inside surface; the region next to the pipe wall was darkened and oxidized and contained multiple crack initiation sites. The adjacent region where the crack extended further into the pipe wall was lighter and cleaner, exhibiting little or no oxidation. The oxidation found in the darkened region most likely occurred while the faces of the fatigue crack were exposed to the atmosphere before the pipe was placed in service. The lighter region indicates that the fatigue crack grew while oil was protecting the crack surfaces from oxidation.

The Safety Board's finite element analysis revealed that the length of the fatigue crack was consistent with the high stress region predicted on the inside surface of the pipe at a bearing or separator strip. Documents show that Enbridge used an engineering company for the specific purpose of inspecting the U.S. Steel pipe until it was stored near the mill. Further, the pipe was transported only a few miles before storage, whereas it was transported about 1,000 miles by rail and truck from storage to construction sites in Minnesota, suggesting a greater likelihood that the pipe was damaged after it was removed from storage. Further, there is no documentation to substantiate that instructions for loading pipe on railroad cars were followed after storage, and no evidence was found to indicate whether pipe loading instructions existed for transportation by truck. Therefore, the stress levels necessary for the initiation and initial growth of the fatigue crack were most likely caused by cyclic forces acting on the pipe during transportation after storage. The finite element analysis for the accident pipe shipment showed that following the rail loading standard, which prescribes size and placement of bearing/separator strips and alignment of the welded seams at 45° to the vertical, would not have resulted in stress levels high enough to initiate fatigue cracking during transportation. Therefore, the Safety Board concludes that, after storage, the accident pipe was likely inadequately loaded for transportation, which led to the initiation of fatigue cracking along a longitudinal seam weld before the pipe was placed in service. The Safety Board further concludes that after installation the preexisting fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

Transportation Fatigue Cracking in Line Pipe

A number of fatigue cracks similar to the one in the Enbridge pipe have led to failures in DSAW (double submerged arc weld) pipe at other locations. Improper positioning of welds when loading pipe joints can create stress in the longitudinal weld during rail transportation that is sufficient to initiate fatigue cracks that are consistent with the type of damage observed in the Enbridge and Colonial pipeline DSAW pipe. As shown in the 1988 metallurgical study of pipe referenced in the current API RP 5L1, fatigue cracks occurring in pipe having various seam types led to 26 pipe failures during initial hydrostatic testing between 1969 and 1987. All of these failures occurred after the pipe had been transported by rail or marine mode.

When compared to the Safety Board's finite element analysis of the static stress developed in the area of a bearing or separator strip (see figure 10) in a stack of 34-inch-diameter, 0.300-inch-wall thickness pipe, the equation in API RP 5L1 for calculating static load stresses underestimated the stresses in the pipe by a factor of approximately 2. However, the Safety Board's analysis indicates that the effectiveness of API RP 5L1 in preventing fatigue crack initiation can be explained by the emphasis on leveling the bearing strips and on the proper alignment of welded seams at 45° to the vertical, leading to a significant reduction in stress at the welds, which are the areas most susceptible to the initiation of fatigue cracking. Although implementation of the recommended practice has resulted in a reduction of railroad transportation fatigue crack initiation, the Safety Board concludes that API RP 5L1, *Recommended Practice for Railroad Transportation of Line Pipe,* may significantly underestimate the stresses in the pipe at the bearing or separator strips. In the case of the accident pipe shipment, regardless of whether the stress levels were underestimated in the rail loading standard, as noted previously, following the rail loading standard would not have resulted in stress levels high enough to initiate fatigue cracking.

API RP 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*, also provides an equation for calculating the static load stress in a stack of pipe for shipment, but this equation is significantly different from the equation in API RP 5L1. When the Safety Board compared the stresses calculated using the equation in API RP

5LW to those determined by the finite element analysis for 34-inch-diameter, 0.300-inch-wall thickness pipe, it found that the equation in API RP 5LW also underestimates the stresses in pipe loaded for transport by a factor of approximately 2. The Safety Board, therefore, concludes that API RP 5LW may significantly underestimate the stresses in the pipe at the bearing or separator strips. The Safety Board believes that the API should review the equations in API RP 5L1 and API RP 5LW for calculating the static load stresses at the bearing or separator strips and revise the recommended practices based on that review.

Natural Gas Pipeline Safety Regulations

To prevent the formation of fatigue cracks during railroad transportation of pipe that is to be used in natural gas service, 49 CFR Part 192.65 (effective November 12, 1970) required shippers to follow the requirements of API RP 5L1 when transporting pipe for which the expected hoop stress during service was equal to or greater than 20 percent of the specified minimum yield strength. When the regulation became effective, pipeline operators were prohibited from using an estimated $13 million of stockpiled pipe that had been transported by rail because operators were unable to verify that the pipe had been transported in accordance with API RP 5L1. RSPA granted an exemption in February 1973 that allowed the installation of this pipe if it were pressure tested to higher pressures than normally required. However, transportation fatigue cracks can grow to failure in service after the pipeline has been pressure tested. Therefore, the Safety Board concludes that hydrostatic pressure testing of a pipeline is insufficient to expose all transportation fatigue cracks that may eventually cause pipe failure. Although the amount of pipe still in stock that was transported before November 12, 1970, without documentation that API RP 5L1 was followed is likely not significant, such pipe could be placed in service. Therefore, the Safety Board believes that RSPA should remove the exemption in 49 CFR 192.65 (b) that permits pipe to be placed in natural gas service after pressure testing when the pipe cannot be verified to have been transported in accordance with API RP 5L1.

Liquid Pipeline Safety Regulations

The RSPA task force report noted that crack growth from fatigue in pipelines is a greater possibility in liquid lines than in gas lines because liquid lines are subject to frequent and substantial pressure cycle variations during normal operations. In contrast to the regulations for transport of natural gas pipe, no similar Federal requirements are applicable to hazardous liquid pipe to ensure that such pipe is protected from fatigue crack initiation during railroad transportation. In a letter to the Safety Board dated July 21, 2003, RSPA indicated that it intends to revise 49 CFR Part 195 for hazardous liquid pipelines to require the use of API RP 5L1, consistent with Part 192 for pipe transportation for gas pipelines. The Safety Board encourages RSPA to promptly amend 49 CFR Part 195 to require that hazardous liquid pipeline operators follow API RP 5L1 for railroad transportation of pipe.

Marine Transportation of Pipe

Pipe shipped by marine transportation has also exhibited transportation-related failures, but the pipeline safety regulations have no requirement that a standard be followed when pipe is transported on a marine vessel. The API recommended practice for transportation of pipe on marine vessels, API RP 5LW, was first issued in 1975 as API RP 5L5. In addition to 9 fatigue failures attributed to rail transportation in the 1988 metallurgical study, 17 fatigue failures were attributed to pipe transported by ship that failed during hydrostatic testing between 1976 and 1987 while the recommended practice was available to the pipeline industry. The Safety Board concludes that there is a potential risk of pipe damage due to fatigue crack initiation during marine vessel transportation of pipe, similar to the risk during rail transportation, for both hazardous liquid and natural gas pipelines. Therefore, the Safety Board believes that RSPA should amend 49 CFR to require that natural gas pipeline operators (Part 192) and hazardous liquid pipeline operators (Part 195) follow API RP 5LW for transportation of pipe on marine vessels.

Truck Transportation of Pipe

Rail transportation has generally been considered to be the most likely source of transit fatigue cracking because of the larger number of pipe rows and high loads, long distances, and long travel times involved. A number of previous pipeline failures have been attributed to rail transportation fatigue, but the pipe also was transported in the field by truck following rail transit. Since no information was available regarding truck loading and transport conditions for the pipe that ruptured, the possibility of fatigue crack initiation during truck transportation cannot be ruled out.

It is reasonable to assume that pipe, in addition to incurring abrasions or dents, could incur fatigue damage during truck transportation. A pipeline industry standard does not exist for the loading requirements for transportation of steel pipe on trucks. Although the Safety Board does not have any data with which to determine the extent of fatigue crack initiation that may occur as a result of highway transportation induced stresses, the Safety Board concludes that the absence of industry loading standards for truck transportation of pipe might create risks to the integrity of both natural gas and hazardous liquid pipelines. The Safety Board, therefore, believes that RSPA should evaluate the need for a truck transportation standard to prevent damage to pipe, and, if needed, RSPA should develop the standard and incorporate it in 49 CFR Parts 192 and 195 for both natural gas and hazardous liquid line pipe.

ASME Pipeline Codes

As noted previously, ASME B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, contains an exemption that allows the installation of pipe that may not have been loaded and transported in accordance with the appropriate API railroad or marine recommended practice with no restriction on when the transportation took place. The exemption allows a hydrostatic pressure test in lieu of compliance with the API recommended practices. The exemption requires a hydrostatic pressure test for a minimum of 2 hours at higher than normally required test pressures. Even though the Federal pipeline safety regulations take precedence in cases of a conflict or apparent conflict with any industry guidance, the Safety Board is concerned that the ASME B31.8 piping code may lead pipeline operators to erroneously believe that pressure testing exposes all fatigue cracks initiated during transportation and verifies the integrity of pipe that may not have been loaded and transported in accordance with API standards. Therefore, the Safety Board believes that ASME should amend ASME B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, to remove the provision that pressure testing may be used to verify the integrity of pipe that may not have been transported in accordance with the API recommended practices for transportation of pipe by railroad or marine vessels.

ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, requires that the transportation of pipe by railroad follow API RP 5L1 but does not require that marine transportation of pipe follow API RP 5LW. The Safety Board believes that ASME should amend ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, to require the use of API RP 5LW for marine transport of pipe.

Pipeline Integrity Management

Hydrostatic pressure testing was performed on Enbridge's pipeline after construction in the 1960s and at various times through the 1980s. As a result of a 1991 fatigue crack rupture, RSPA required Enbridge to develop an operational reliability assessment that included additional pressure tests and to make changes to pipeline operations that included lowering pressure cycle stress in order to improve pipeline integrity. A number of defects failed during the 1991–1992 hydrostatic pressure testing, including some fatigue cracks. By 1995, RSPA had approved Enbridge's use of an in-line inspection tool, the Elastic Wave tool, to find pipe cracks, rather than hydrostatic pressure testing. By using this tool, Enbridge found a number of cracks that the company repaired before failure. By 1998, the interval for in-line crack tool reinspection had been established as 10 years from the previous inspection. The pipeline section that failed in this accident had last been inspected in May 1996 with an in-line crack-detection tool, which was run approximately 6 years before the rupture.

In the May 1996 inspection, an indication was present at the point where the pipe later ruptured on July 4, 2002, but the indication did not exhibit the diamond-shaped signature typical of a crack and did not meet the inspection company's interpretation standard of at least 6 of 10 feature selection criteria to identify it as a crack. After the accident, the inspection company's analysis confirmed that the indication did not meet the feature selection criteria. RSPA's postaccident review concurred with this analysis. The Safety Board concludes that the Elastic Wave in-line inspection conducted before the accident recorded an indication at the point where the pipe eventually failed; however, preaccident and postaccident interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack. Relatively large cracks can be found when a pipe fails during hydrostatic pressure testing; however, the potential also exists for smaller cracks to grow but not fail during a pressure test and then continue to grow due to normal operational pressure cycle stress. In its report of the 1980 accident in Manassas, Virginia, the Safety Board noted that it is unlikely that all fatigue cracks will be found during hydrostatic pressure testing. To expose fatigue cracks on the 34-inch pipeline in 1991, Enbridge used hydrostatic pressure testing. However, smaller fatigue cracks that remained in the pipe continued to grow to the point of failure before the next pressure test. Within 2 1/2 years of an Enbridge pressure test, two fatigue cracks failed, resulting in crude oil leaks. The Enbridge metallurgical evaluation indicated that the stress developed during hydrostatic testing was sufficient to propagate the cracks but insufficient to cause an immediate failure. Beginning in 1995, Enbridge inspected its entire 34-inch pipeline in the United States using the Elastic Wave in-line inspection tool. Enbridge's policy was to excavate all reported crack defects for evaluation whether or not the affected pipeline segment was in a high-consequence area.

After this accident, RSPA reviewed the data from the 1995–1996 Mark II Elastic Wave inspection tool for the failed joint of pipe. That review confirmed that the inspection log data showed an indication in the pipeline at the point of rupture; however, the data did not meet the crack identification criteria established by the inspection company. As a result of this accident, RSPA informed the Safety Board on July 21, 2003, that it plans to issue an advisory bulletin to all pipeline operators about reevaluating previous Mark II Elastic Wave tool inspections used to detect crack-like defects near the longitudinal weld and taking remedial action necessary to ensure the continued integrity of the pipeline. In addition, according to RSPA, pipeline operators will be issued a directive to monitor pressure cycles to verify that assumptions made in the original remaining life analyses for cracks remain valid and to ensure that input parameters are within the tool tolerance range and detection level when analytical methods are used to establish retesting intervals. Furthermore, RSPA will modify the forms it uses to guide comprehensive integrity management audits to ensure that pipeline operators adhere to the requirements of the advisory bulletin. The Safety Board supports the completion of these actions that can be taken now by pipeline operators to improve pipeline integrity.

RSPA, with the financial assistance of industry trade associations, is also conducting research leading to the development of a quantitative basis for evaluating the significance of pipe material and construction features having time-, environment-, and cycle-dependent growth mechanisms (which includes fatigue cracking) that threaten pipeline integrity in natural gas transmission pipelines. In addition to evaluating the significance of defects in pipe seams, the study will assess defects in pipe manufacturing, pipeline construction, pipe base metal, girth welds, and fabrication welds to quantify conditions under which otherwise benign material and construction features can become active and grow to failure. The research will examine the threats to natural gas pipeline integrity including external and internal corrosion, stress corrosion cracking, and fatigue cracks. The research is intended to identify the conditions that cause the defects to grow and will not be limited to operating pressure or hydrostatic pressure testing. An evaluation technique will also be created for pipeline operators to develop effective mitigation criteria for their pipelines. The Safety Board agrees that, in addition to fatigue cracking, other types of time-, environment-, and cycle-dependent defects need to be considered when evaluating threats to hazardous liquid pipeline integrity. If RSPA is satisfied with the results of the natural gas research, the study could be extended to include hazardous liquid pipelines, and the Board encourages RSPA to proceed with the hazardous liquid pipeline research to better evaluate pipeline integrity.

In the past, Enbridge had modified the expected crack growth rate from pressure cycle stress based on knowledge gained from investigating prior failures that occurred on the 34-inch-diameter pipeline system. However, in 2001 Enbridge started using the UltraScan CD, a more technically advanced in-line crack inspection tool, for in-line inspections of its 34-inch line in the United States. Since the accident, Enbridge has studied crack growth due to pressure cycle stress using its current crack growth rate model. The company based the study on various sizes of potential fatigue cracks that the UltraScan CD tool was specified to find. For this study, Enbridge assumed that cracks of various sizes would not be found by the inspection tool, then performed an analysis, with the reduced pipeline pressure cycles Enbridge intends to achieve, to project how long those cracks would continue to grow until they might fail. The largest potential crack evaluated in the study was one that was two times the depth and three times the length of the threshold size of a crack that the UltraScan CD tool could detect. The analysis concluded that a crack this large would still have a predicted remaining life of 6.5 years. As a result of the crack-growth evaluation, Enbridge is now proposing to RSPA that it perform the next in-line inspection in the Clearbrook to Superior 34-inch pipeline section using the more advanced in-line crack inspection tool within 3 years of the last inspection.

On September 5, 2003, RSPA requested modifications to Enbridge's return-to-service plan, which include running the UltraScan CD tool in 2005 and analyzing crack growth rate after the reinspection. Enbridge responded that it would reinspect the line between Clearbrook and Superior in 2005 and use the resulting data to refine crack growth rates and determine future integrity requirements. Because cycle-dependent growth is a factor in fatigue crack failures, adhering to operating practices that limit the number and magnitude of pipeline pressure cycles is critical to limiting crack growth. Enbridge also has committed to monitoring and analyzing pressure cycle data on a quarterly basis and to sending each analysis to RSPA at least until the in-line crack tool inspection of the Clearbrook to Superior section is completed in 2005. The Safety Board supports efforts to monitor operating data and refine crack growth rate estimates to help determine appropriate in-line reinspection intervals.

The Federal pipeline safety regulations require that certain actions be taken when conditions are found that could affect pipeline safety. Enbridge's policy regarding fatigue cracks has been and still is to run an in-line crack inspection tool in the entire 34-inch pipeline regardless of high-consequence area designation. Before RSPA's integrity management rule, Enbridge analyzed the crack failure data and established a reinspection time interval for its 34-inch pipeline based on an engineering evaluation of the crack growth rate. Now, RSPA's integrity management rule for high-consequence areas, 49 CFR 195.452 (e), requires that a hazardous liquid operator consider all risk factors to establish an assessment schedule, including the "results of a previous assessment, the defect type and size that the defect assessment method can detect, and the defect growth rate."

Conclusions

Findings

1. Enbridge's pipeline control center personnel responded in a timely manner to the indications of a pipeline leak.

2. After storage, the accident pipe was likely inadequately loaded for transportation, which led to the initiation of fatigue cracking along a longitudinal seam weld before the pipe was placed in service.

3. After installation the preexisting fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

4. The American Petroleum Institute recommended practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe,* and American Petroleum Institute recommended practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,* may significantly underestimate the stresses in the pipe at the bearing or separator strips.

5. Hydrostatic pressure testing of a pipeline is insufficient to expose all transportation fatigue cracks that may eventually cause pipe failure.

6. There is a potential risk of pipe damage due to fatigue crack initiation during marine vessel transportation of pipe, similar to the risk during rail transportation, for both hazardous liquid and natural gas pipelines.

7. The absence of industry loading standards for truck transportation of pipe might create risks to the integrity of both natural gas and hazardous liquid pipelines.

8. The Elastic Wave in-line inspection conducted before the accident recorded an indication at the point where the pipe eventually failed; however, preaccident and postaccident interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured.

Recommendations

As a result of its investigation of the July 4, 2002, pipeline rupture near Cohasset, Minnesota, the National Transportation Safety Board makes the following safety recommendations:

To the Research and Special Programs Administration:

Remove the exemption in 49 *Code of Federal Regulations* 192.65 (b) that permits pipe to be placed in natural gas service after pressure testing when the pipe cannot be verified to have been transported in accordance with the American Petroleum Institute recommended practice 5L1. (P-04-01)

Amend 49 *Code of Federal Regulations* to require that natural gas pipeline operators (Part 192) and hazardous liquid pipeline operators (Part 195) follow the American Petroleum Institute recommended practice 5LW for transportation of pipe on marine vessels. (P-04-02)

Evaluate the need for a truck transportation standard to prevent damage to pipe, and, if needed, develop the standard and incorporate it in 49 *Code of Federal Regulations* Parts 192 and 195 for both natural gas and hazardous liquid line pipe. (P-04-03)

To the American Society of Mechanical Engineers:

Amend American Society of Mechanical Engineers B31.8, *Gas Transmission and Distribution Piping Systems*, section 816, to remove the provision that pressure testing may be used to verify the integrity of pipe that may not have been transported in accordance with the American Petroleum Institute recommended practices for transportation of pipe by railroad or marine vessels. (P-04-04)

Amend American Society of Mechanical Engineers B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*, section 434.4, to require the use of the American Petroleum Institute recommended practice 5LW for marine transport of pipe. (P-04-05)

To the American Petroleum Institute:

Review the equations in American Petroleum Institute recommended practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe*, and American Petroleum Institute recommended practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*, for calculating the static load stresses at the bearing or separator strips and revise the recommended practices based on that review. (P-04-06)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

MARK V. ROSENKER
Vice Chairman

JOHN J. GOGLIA
Member

CAROL J. CARMODY
Member

RICHARD F. HEALING
Member

Adopted: June 23, 2004

Chairman Ellen Engleman Conners did not participate in the adoption of this report.

Appendix A

Investigation

The National Transportation Safety Board was notified on July 4, 2002, through the National Response Center, of a pipeline release in an isolated, swampy area west of Cohasset, Minnesota. The Safety Board dispatched an investigative team from its Washington, D.C., headquarters. The team comprised investigative groups in pipeline operations, SCADA, and emergency response. No Board member accompanied the investigative team. No depositions or hearings were held in conjunction with the investigation. Enbridge Pipelines (Lakehead), LLC; PII North American, Inc.; United States Steel Corporation; the Minnesota Office of Pipeline Safety; Minnesota Pollution Control; the Minnesota Department of Natural Resources; the Cohasset Fire Department; and RSPA's Office of Pipeline Safety were parties to the investigation.

One accident (in 2007) reported 2 fatalities. No other fatalities or injuries were reported for Operator 11169

OPERATOR_ID	11169

Count of RPTID	IYEAR	
FATAL	2007	Grand Total
2	1	1
Grand Total	1	1

Accidents with lost product of 20 Barrels or more (I'm not sure where "significance" is achieved in this case).

OPERATOR_ID	11169

Count of RPTID	IYEAR							
LOSS	2002	2003	2004	2005	2006	2007	2008	2009
20					1			
40			1					
47		1						
50	2							
100		1		1				
115							1	
125		1						
154								1
260							1	
325						1		
500		1						
700		1						
1003			1					
1500						1		
4500		1						
4800						1		
6000	1							
Grand Total	3	6	2	1	1	3	2	1

Accidents with total property damage of $500k or more (I'm not sure where "significance" is achieved in this cas

OPERATOR_ID	11169

Count of RPTID	IYEAR				
PRPTY	2002	2003	2004	2007	Grand Total
702500				1	1
1000000		1			1
1089790			1		1
2625000				1	1
2853000		1			1
4503458				1	1
5597300	1				1
Grand Total	1	2	1	3	7

Accidents that reached water

OPERATOR_ID	11169

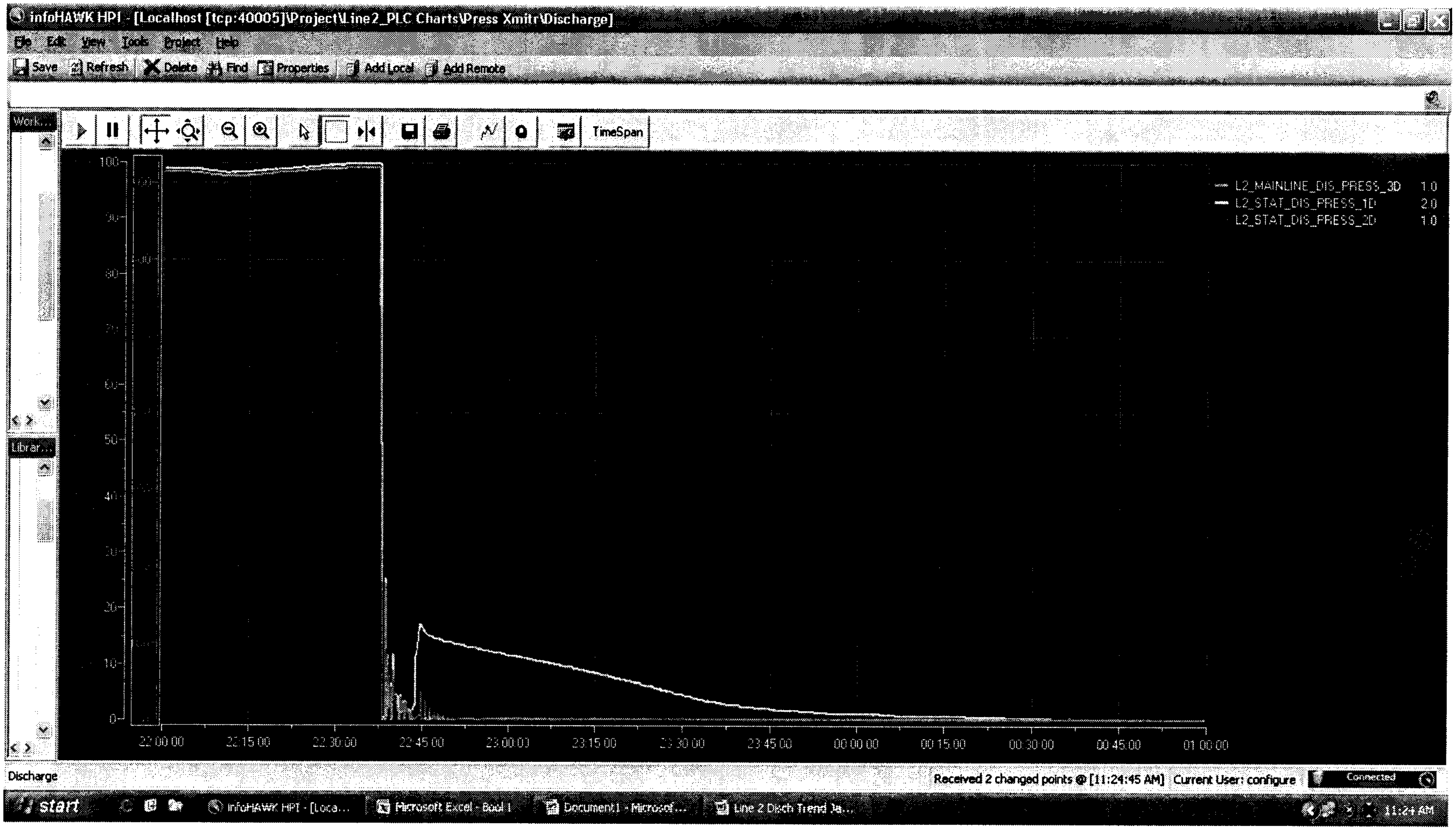
Count of RPTID	IYEAR

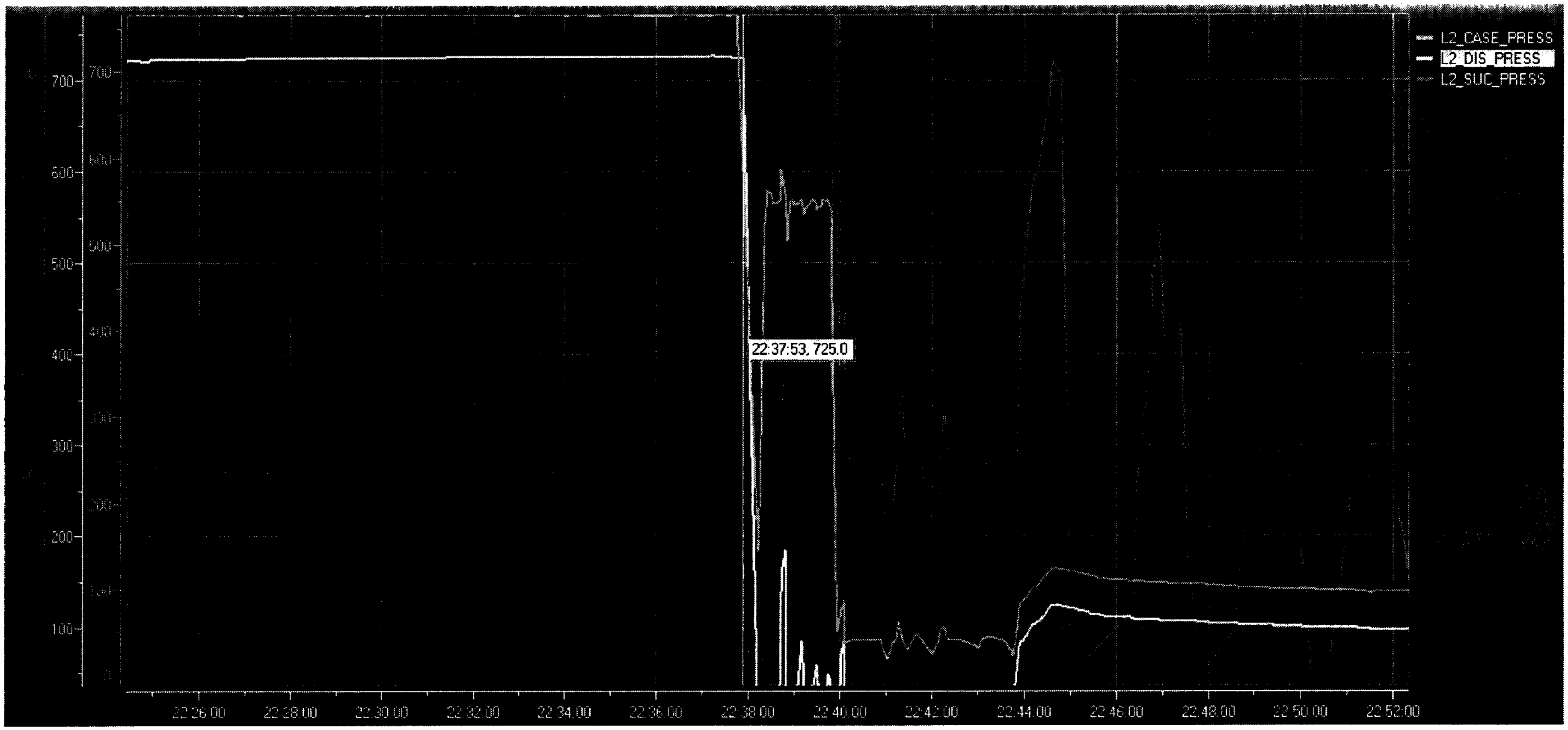
WATER	2002	2003	2004	2005	2006	2007	Grand Total
Yes	1	1	3	1	1	3	10
Grand Total	1	1	3	1	1	3	10

Grand Total
1
1
1
2
2
1
1
1
1
1
1
1
1
1
1
1
1
19

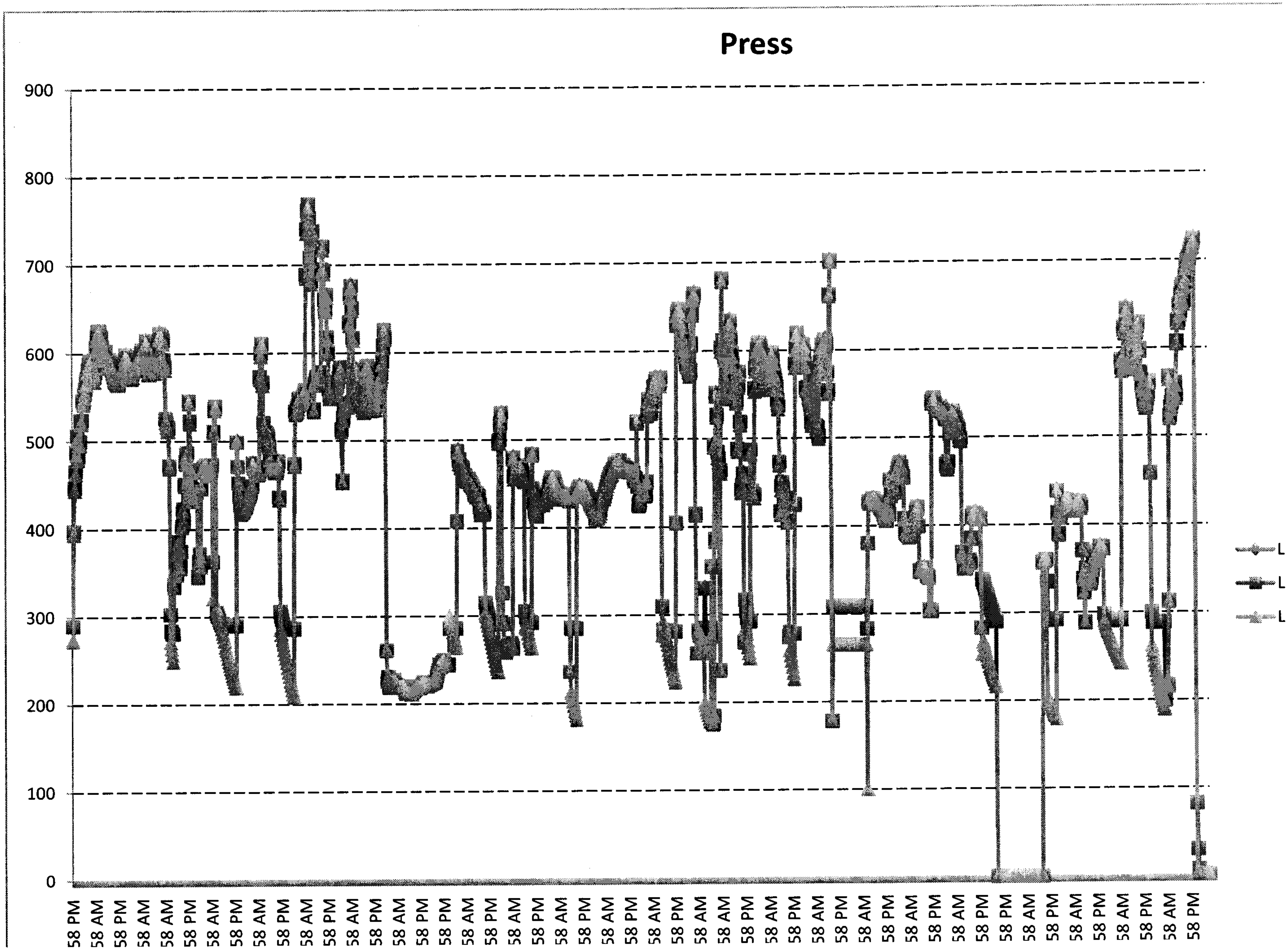
e).

Time	Message	Value
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	False
Saturday, January 09, 2010 3:49:28 PM	STATION SECTIONALIZING VALVE SELECTOR SWITCH IN LOCAL	True
Friday, January 08, 2010 10:49:09 PM	LINE FULLY ISOLATED	True
[illegible]	[illegible]	False
Friday, January 08, 2010 10:43:56 PM	LINE SECTIONALIZED SUCCESSFULLY	True
[illegible]	[illegible]	False
[illegible]	[illegible]	False
[illegible]	[illegible]	False
[illegible]	[illegible]	False
[illegible]	[illegible]	False
[illegible]	[illegible]	False
Friday, January 08, 2010 10:40:38 PM	STATION VALVES NOT IN PROPER OPERATING POSITION	True
Friday, January 08, 2010 10:40:38 PM	STATION AUTO RESET SHUTDOWN ACTIVE	True
Friday, January 08, 2010 10:38:21 PM	STATION CASCADE SHUTDOWN	True
Friday, January 08, 2010 10:38:19 PM	SITE LOW SUCTION PRESSURE FROM TRANSMITTER	True
Friday, January 08, 2010 10:38:19 PM	LOW SUCTION PRESSURE	True
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	False
[illegible]	[illegible]	False
Friday, December 25, 2009 11:04:17 AM	STATION VALVES NOT IN REMOTE	True
Friday, December 25, 2009 11:04:16 AM	STATION REC TRAP IN VALVE SELECTOR SWITCH IN LOCAL	True


infoHAWK HPI - [Localhost [tcp:40005]\Project\Line2_PLC Charts\Press Xmitr\Discharge]
File Edit View Tools Project Help
Save Refresh Delete Find Properties Add Local Add Remote
TimeSpan
100
90
80
70
60
50
40
30
20
10
0
22:00:00 22:15:00 22:30:00 22:45:00 23:00:00 23:15:00 23:30:00 23:45:00 00:00:00 00:15:00 00:30:00 00:45:00 01:00:00
L2_MAINLINE_DIS_PRESS_3D 1.0
L2_STAT_DIS_PRESS_1D 2.0
L2_STAT_DIS_PRESS_2D 1.0
Discharge
Received 2 changed points @ [11:24:45 AM] Current User: configure
Connected
start
infoHAWK HPI - [Loca...
Microsoft Excel - Book1
Document1 - Microsof...
Line 2 Disch Trend Ja...
11:24 AM



L2_CASE_PRESS
L2_DIS_PRESS
L2_SUC_PRESS
22:37:53, 725.0
700
600
500
400
300
200
100
22:26:00
22:28:00
22:30:00
22:32:00
22:34:00
22:36:00
22:38:00
22:40:00
22:42:00
22:44:00
22:46:00
22:48:00
22:50:00
22:52:00



Press
900
800
700
600
500
400
300
200
100
0
L
L
L