SMART ACTIVITY ID
129773
RECEIVED MAY 2 0 2010

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:	Jeff Murray 4/27/2010	**Inspector/Submit Date: Jeff Murray 4/27/2010** Jeff Murray **Peer Reviewer/Date:** 5/19/2010 **Director Approval**

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	ENBRIDGE ENERGY, LIMITED PARTNERSHIP.		**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:	Crude Oil		
Inspection Type:	Accident Investigation Involving Hazardous Liquid	**Inspection Date(s): No Site Visit**	
For OPS :			**AFO Days:**
For MNOPS :	Jeff Murray		**AFO Days: 0**
MNOPS CASE #: 1164771			

Synopsis:

On 4/17/2010 Jeff Murray was notified by the Minnesota Duty Officer, (DO) that the Minnesota Department of Natural Resources, (DNR) reported a sheen on wetlands water located just South/East of Deer River, Minnesota. Jeff Murray then initially spoke with Troy Carlson of Enbridge who was on-site. Troy indicated that the Enbridge facilities in that area had been shut down and absorbent booms had been installed on-site and that any oil that was present had been contained. At that time, the cause of the sheen and/or extent and cause of oil release had not been determined.

Later in the day on 4/17/2010 Jeff Murray received updates from Mark Willoughby and Adam Erikson with Enbridge. The source of the oil was a leak on Enbridge line 2, 26" diameter pipeline. It was estimated that the leak was up to 5 barrels and reported in the NRC report as such. Enbridge reported that the leak resulted from a linear defect along the long seam of the pipeline located approximately ½ inch in length and approximately 10 inches away from a girth weld. It was reported that no indications of corrosion in the immediate location of the failure existed. At that time, Enbridge reported it was difficult to estimate the extent of the oil loss since the site contained only oily residue but no free product. They reported that the oily residue extended approximately 400 feet along the ditch. On 4/17/2010 Enbridge indicated they intended to install a Plidco sleeve as a temporary repair however due to the history of line 2, Enbridge was required to gain approval by PHMSA prior to any repair on the line. Once approval was granted a

temporary Plidco Sleeve was installed and the line is currently being monitored 24 hours a day until a permanent repair or cut-out is performed.

Summary:

On 4/17/2010 Jeff Murray was notified by the MN Duty Officer that the Minnesota Department of Natural Resources, (DNR) reported a sheen on wetlands water located just South/East of Deer River, Minnesota. Enbridge facilities in that area had been shut down and absorbent booms had been placed on-site to contain any oil. Enbridge had determined the source of the oil was a leak on their line 2, 26" diameter pipeline. It was estimated that the leak was up to 5 barrels. It was reported that the leak was a linear defect along the long seam of the pipeline approximately ½" in length and approximately 10" away from a girth weld. Temporary Plidco Sleeve was installed and the line is currently being monitored 24 hours a day until a permanent repair or cut-out is performed.

Enbridge Pipelines (Lakehead) L.L.C.
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ENBRIDGE™

April 19, 2010

Ivan A Huntoon
Director, Central Region
Office of Pipeline Safety
901 Locust Street, Room 462E
Kansas City MO 64106

Re: Enbridge Line 2 Pipeline Return to Service

Dear Mr. Huntoon:

The intent of this letter is to advise your agency of the steps taken specific to the repair and return to service of Enbridge's Line 2, 26 inch pipeline in response to the April 17, 2010 leak at milepost 997.79, approximately one and one half mile downstream of the Company's Deer River pump station. Enbridge has implemented the activities outlined below in order to safely return the line to service:

- Completed in field NDE seam assessment including ultrasonic testing and magnetic particle inspection of the entire long seam of the affected joint.
- Integrity assessment correlating most recent ILI run data as compared to field data/results and evaluation for similar ILI features.
- Repair using a bolted PLIDCO Split Sleeve on April 18th
- Communicated Enbridge's Return to Service Plan to PHMSA and MNOPS during a conference call with agency representatives on April 18th.

Following the conference call with PHMSA and MNOPS, Enbridge returned the line to service under the following conditions:

- Additional pressure restrictions were imposed at Line 2 pump stations from Gretna to Superior at 90 % of the previous 90 day high (see new pressure allowable chart depicted below).
- The PLIDCO Split Sleeve installed over the leaking defect will be continuously monitored until weld up is completed, in accordance with Enbridge procedures. Enbridge's Superior Region will look to schedule this based on the most favorable site and operating conditions.
- Enbridge will supplement code required ROW inspections with ground inspections through the spring thaw seasonal period, ending June 30, 2010. The inspections will specifically monitor an area 10 miles downstream of each Line 2 pump stations in locations where similar features have been identified by ILI.
- The Enbridge System Compliance and Integrity Department will schedule a meeting with the Minnesota Office of Pipeline Safety to review Line 2 integrity and repairs at a mutually agreeable time in the future.
- Enbridge will cut-out the affected pipe section and conduct a metallurgical analysis of the defect.

Line 2 Updated Discharge Pressure Restrictions

Station	Discharge Pressure Restriction January 12th, 2010	Revised Discharge Pressure Restriction April 18, 2010
Gretna	580	**522.9**
Donaldson	623	**546.3**
Viking	524	**443.7**
Plummer	543	**443.7**
Clearbrook	644	**497.7**
North Cass Lake	614	**482.4**
Deer River	593	**493.2**
Floodwood	505	**414**

As of late evening yesterday, Enbridge successfully restarted Line 2 in accordance with the above defined conditions. We will keep PHMSA and MNOPS advised of future key Line 2 investigation events/milestones.

Should you require further information, please contact me at (715) 394-1445.

Sincerely,

Shaun Kavajecz

c: Steve Irving
Elizabeth Skalnek - Minnesota Office of Pipeline Safety

RECEIVED APR 1 2 2010 Activity ID 124124

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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.**

Brad K. Ardner

Inspection Report	Post Inspection Memorandum	
Inspector/Submit Date: Brad Ardner /03/26/10	**Inspector/Submit Date:**	Brad Ardner /03/26/10
	Peer Review/Date:	Elizabeth Skalnek ESS 4/7/2010
	Director Approval/Date:	Ivan Huntoon IS for IKH 4/16/2010

POST INSPECTION MEMORANDUM (PIM)	
Name of Operator: Enbridge Energy Limited Partnership	**OPID #:** 11169
Name of Unit(s): Superior Region, Minnesota Portion	**Unit # (s):** 3083
Records Location: Superior, WI	
Unit Type & Commodity: Hazardous Liquid Interstate Transmission - Crude/NGL	
Inspection Type: Standard - Field and Records	**Inspection Date(s):** June 29 - July 2, 2009
PHMSA Representative(s): MNOPS - Brad Ardner & Elizabeth Skalnek	**AFO Days:** Ardner - 4, Skalnek - 2

Summary:

The field and records portion of the Standard Inspection was conducted on Enbridge Pipeline June 29- July 2, 2009. The unit to be inspected is # 3083 Superior Region, Minnesota Portion, which includes all three designated inspection units in MN. A Joint Team O&M Inspection was conducted in May of 2006. Inspection of their procedures was limited to the review of revisions to existing procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates to their O&M. Records were reviewed at the Enbridge office in Superior WI, followed by physical on-site visits. Facilities visited included; five (5) main line block valve stations, eleven (11) pump stations, three (3) rectifiers, a densitomitor station, Mississippi River crossing, pre-tested pipe stored in Bemidiji, MN, and a critical bond between Enbridge and Great Lakes Transmission. The range of the right-of-way was from MP 805 (NW) to MP 1052 (NE).

Findings:

The records and field verifications were checked per pages 17-21 of the PHMSA Form 3. No procedures were reviewed except those needed for clarification. An Operator Qualification Veification (PHMSA Form 15) and the Drug and Alcohol (PHMSA Form 13) were completed and is attached.

No deficiencies or non-compliances were noted at the time of the audit. MNOPS anticipates no further actions in this MNOPS Case 1102024.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: Enbridge Energy Limited Partnership	
OP ID No. [1] 11169	**Unit ID No.** [1] 3083
H.Q. Address:	**System/Unit Name & Address:** [1]
1100 Louisiana, Suite 3200 Houston, TX	Superior Region 119 North 25th Street East Superior, WI 54880
Co. Official: Terry McGill - VP Senior & Chief Operating Officer	**Activity Record ID#:**
Phone No.: 712-821-2003	**Phone No.:**
Fax No.:	**Fax No.:**
Emergency Phone No.: 800-858-5253	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Randy Wilberg	Safety, Training & Compliance Coordinator	715-394-1412
Patsy Bolk	Compliance Coordinator	715-394-1504
Dave Hoffman	Supervisor, Compliance	715-394-1523
Mike Goman	Manager, Technical Services	715-394-1523
John Bissell	Senior Cathodic Protection Specialist	715-394-1417

PHMSA Representative(s) [1]
MNOPS - Brad Ardner & Elizabeth Skalnek

Inspection Date(s) [1] **June 29 - July 2, 2009**

Company System Maps (copies for Region Files):

Unit Description:
Interstate Hazardous Liquid transmission pipeline operator, consisting of six (6)pipelines and approximately one thousand, two hundred forty-four (1244) miles of pipe in Minnesota.

Portion of Unit Inspected [1]
Superior Region, Minnesota portion.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/07/04 and

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

03/23/09.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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CONVERSION TO SERVICE		S	U	N/A	N/C
* .5	Has a written procedure been developed addressing all applicable requirements and followed? Amt. 195-86 Pub. 06/09/06 eff. 07/10/06.				X

REGULATED RURAL GATHERING LINES		S	U	N/A	N/C
* .11	Regulated Rural Gathering Lines as defined in 195.11(a) must comply with the safety requirement outlined in 195.11(b). Amt. Pub. 06/03/08 eff. 07/03/08.				

LOW-STRESS PIPELINES IN RURAL AREA		S	U	N/A	N/C
* .12	Regulated Low-stress Pipelines in Rural Area as defined in 195.12(a) must comply with the safety requirement outlined in 195.12(b). Amt. Pub. 06/03/08 eff. 07/03/08.				

Comments:
No conversion to service in MN.

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				X
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by '195.422 and '195.200.						
*		Welding must be performed by qualified welders using qualified welding procedures.				X
.402(c)/ .422	.214(a)	Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 Pub. 6/14/04, eff. 7/14/04.				X
		Welding procedures must be qualified by destructive testing.				X
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2004 Ed. Including addenda through July 1, 2005), except that a welder qualified under an earlier edition than listed in '**195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 195-81 corr. Pub. 9/09/04; Amt 195-86 Pub. 06/09/06 eff. 07/10/06.				X
	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104.				X
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				X
	.226(b)	If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed. Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate).**				X
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				X
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **195.228(b)** and per the requirements of **195.234** in regard to the number of welds to be tested? Amdt. 195-81 Pub. 6/14/04, eff. 7/14/04.				X
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				X
		2. By qualified personnel				X
		3. By a process that will indicate any defects that may affect the integrity of the weld				X
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				X
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), .303, and .305(b) for exceptions).				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
	.302(b)/ .302(c)	Except for lines converted under ' **195.5**, the following pipelines may be operated without having been pressure tested per Subpart E and without having established MOP under 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure]. - .302(b)(2)(ii): Any carbon dioxide pipeline constructed before July 12, 1991, that is located in a rural area as part of a production field distribution system. - .302(b)(3): Any low-stress pipeline constructed before August 11, 1994, that does not transport HVL. - .302(b)(4)/.303: Those portions of older hazardous liquid and carbon dioxide pipelines for which an operator has elected the risk-based alternative under §195.303 and which are not required to be tested based on the risk-based criteria.				
		Have pipelines <u>other than those described above</u> been pressure tested per Subpart E?				X
		If pipelines <u>other than those described above</u> have not been pressure tested per Subpart E, has MOP been established under 195.406(a)(5), in accordance with .302(c)? Note: Establishing MOP under 195.406(a)(5) only applies to specified "older" pipelines constructed prior to the dates in .302(b).				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with ' **195.302**.				X
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
	.310(b)(10)	Temperature of the test medium or pipe during the test period.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES				S	U	N/A	N/C
.402(a)	**.402**	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	**.402(c)**	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				X
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				X
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				X
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by ' **195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				X
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by ' **195.406**?				X
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under ' **195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				X
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				X
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59.				X
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				X
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				X
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				X
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				X
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				X
		iii. Loss of communications?				X
		iv. The operation of any safety device?				X
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				X
	.402(d)(2)	Checking variations from normal operation after abnomal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	**.403(a)**	Each operator shall establish and conduct a written continuing training program to instruct emergency response personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under 195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X
	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition.				X
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				X
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				X
	.403(b)(2)	Make appropriate changes to the emergency response training program				X
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
.402(a)	**.402(c)(1)**	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				X
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				X
		ii. Pump stations				X
		iii. Scraper and sphere facilities				X
		iv. Pipeline valves				X
		v. Facilities to which ' **195.402(c)(9)** applies				X
		vi. Rights-of-way				X
		vii. Safety devices to which ' **195.428** applies				X
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				X
	.404(a)(3)	The maximum operating pressure of each pipeline.				X
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				X
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				X
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under ' **195.402** apply.				X
	.404(c)	Each operator shall maintain the following records for the periods specified:				

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		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				X
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				X
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.				X

Comments:
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		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	.406(a)(1)	The internal design pressure of the pipe determined by **195.106**. Amt. 195-86 Pub. 06/09/06 eff. 07/10/06.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				X
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **195.402(c)(9)**.				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

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LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				X
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt. 195-82 Pub. 8/10/04, eff. 9/09/04.			X	
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt. 195-82 Pub. 8/10/04, eff. 9/09/04.			X	
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt. 195-82 Pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone. Amdt. 195-82 Pub. 8/10/04, eff. 9/09/04.			X	
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt. 195-82 Pub. 8/10/04, eff. 9/09/04.			X	
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt. 195-82 Pub. 8/10/04, eff. 9/09/04.			X	
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections			X	

Comments:
195.402(a) No off shore pipeline in this system.

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VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				X
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year.				X
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				X

Comments:

PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under **195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under **195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
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SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X

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SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

OVERPRESSURE SAFETY DEVICE PROCEDURES			S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				X
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.				X
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				X
*	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Amt. 195-86 Pub. 06/09/06 eff. 07/10/06. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				X
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				X
		The equipment must be:				
		a. In proper operating condition at all times.				X
		b. Plainly marked so that its identity as firefighting equipment is clear.				X
		c. Located so that it is easily accessible during a fire.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

BREAKOUT TANK PROCEDURES	S	U	N/A	N/C

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BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				X
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under ' **195.402(c)(3)**. -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years				X
*	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.** Amt. 195-86 Pub. 06/09/06 eff 07/10/06.				X
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
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SIGN PROCEDURES			S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.				X

Comments:
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SECURITY of FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

SMOKING OR OPEN FLAME PROCEDURES			S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:

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PUBLIC AWARENESS PROGRAM PROCEDURES (In accordance with API RP 1162)			S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program also in accordance with API RP 1162 (Amdt. 192-83 Pub. 5/19/05 eff. 06/20/05)				
*	.440(d)	The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: Amdt. 195-83 Pub. 5/19/05, eff. 06/20/05.				
		(1) Use of a one-call notification system prior to excavation and other damage prevention activities;				X
		(2) Possible hazards associated with unintended releases from a hazardous liquids or carbon dioxide pipeline facility;				X
		(3) Physical indications of a possible release;				X
		(4) Steps to be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; and				X
		(5) Procedures to report such an event (to the operator).				X
* *	.440(e)	The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. Amdt. 195-83 Pub. 5/19/05, eff. 06/20/05.				X
*	.440(f)	The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports hazardous liquid or carbon dioxide. Amdt. 195-83 Pub. 5/19/05, eff. 06/20/05.				X
	.440(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area. Amdt. 195-83 Pub. 5/19/05, eff. 06/20/05.				X

Comments:
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DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API RP 1162)			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				X
	.442(b)	Does the operator participate in a qualified One-Call program?				X
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				X
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph **(c)(1)** of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				X
		ii. How to learn the location of underground pipelines before excavation activities are begun.				X
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				X
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				X
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				X

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DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API RP 1162)			S	U	N/A	N/C
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				X
		ii. In the case of blasting, any inspection must include leakage surveys.				X

Comments:
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CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
.402(a) *	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training? Amt. 195-86 Pub. 06/09/06 eff. 07/10/06.				X

Comments:
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PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

SUBPART H - CORROSION CONTROL PROCEDURES			S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X

		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**?				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X
*	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2002** (incorporated by reference). Amt. 195-86 Pub. 06/09/06 eff. 07/10/06.				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**				X
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.				X
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-2002.** Amt. 195-86 Pub. 06/09/06 eff. 07/10/06.				X
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				X
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months**				X
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**				X
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				X
.575	Are there adequate provisions for electrical isolations?				X
.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				X
.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				X
	b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				X
	Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7½ months.**				X
	c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				X
.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				X
.583	Atmospheric corrosion monitoring -				
	ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				X
	OFFSHORE - At least **once each year, but at intervals not exceeding 15 months**				X
.585	a. Are procedures in place to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				X
	b. Are procedures in place to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				X
.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**				X
.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				X

Comments:
Not checked as part of this audit. Inspection of their procedures was limited to the review of revisions to new or revised procedures since the last O&M inspection in May 2006 or last Standard Inspection when code changes required updates.

	PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES	S	U	N/A	N/C
Subparts A - C	Drug & Alcohol Testing & Alcohol Misuse Prevention Program – Use PHMSA Form # 13, PHMSA 2008 Drug and Alcohol Program Check.				

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory	X			
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers	X			
.412	ROW/Crossing Under Navigable Waters	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - FIELD REVIEW		S	U	N/A	N/C
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings - Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks	X			
.434	Signs - Pumping Stations - Breakout Tanks	X			
.436	Security - Pumping Stations - Breakout Tanks	X			
.438	No Smoking Signs	X			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.575	Electrical Isolation; shorted casings	X			
.583	Atmospheric corrosion - Exposed pipeline components (splash zones, water spans, soil/air interface, under thermal insulation, disbanded coatings, pipe supports, deck penetrations, etc.)	X			

PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
CONVERSION TO SERVICE					
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
REPORTING					
.48 / .49	Annual Report (DOT form PHMSA F7000-1.1Beginning no later than June 15, 2005) (As of January 5, 2009, an operator of a rural low-stress hazardous liquid pipeline is not required to complete Parts J and K of the hazardous liquid annual report form (PHMSA F 7000-1.1) required by § 195.49 or to provide the estimate of total miles that could affect high consequence areas in Part B of that form.)	X			
.52	Telephonic Reports to NRC (800-424-8802)	X			
.54(a)	Written Accident Reports (DOT Form 7000-1)	X			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	X			
.56	Safety Related Conditions	X			
.57	Offshore Pipeline Condition Reports			X	
.59	Abandoned Underwater Facility Reports			X	
CONSTRUCTION					

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.204	Construction Inspector Training/Qualification	X			
.214(b)	Test Results to Qualify Welding Procedures	X			
.222	Welder Qualification	X			
.234(b)	Nondestructive Technician Qualification	X			
.589	Cathodic Protection	X			
.266	Construction Records	X			
.266(a)	Total Number of Girth Welds	X			
	Number of Welds Inspected by NDT	X			
	Number of Welds Rejected	X			
	Disposition of each Weld Rejected	X			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	X			
.266(c)	Location of each Crossing with another Pipeline	X			
.266(d)	Location of each buried Utility Crossing	X			
.266(e)	Location of Overhead Crossings	X			
.266(f)	Location of each Valve and Test Station	X			
PRESSURE TESTING					
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			
.308	Records of Pre-tested Pipe	X			
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities	X			
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Receiving notices of abnormal or emergency conditions and sending it to appropriate personnel and government agencies.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)	X			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).	X			
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)	X			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			
	PUBLIC AWARENESS PROGRAM				
.440(e & f)	Documentation properly and adequately reflects implementation of operator's Public Awareness Program requirements - Stakeholder Audience identification, message type and content, delivery method and frequency, supplemental enhancements, program evaluations, etc. (i.e. contact or mailing rosters, postage receipts, return receipts, audience contact documentation, etc. for emergency responder, public officials, school superintendents, program evaluations, etc.). See table below.	X			

API RP 1162 Baseline* Recommended Message Delivery Frequencies	
Stakeholder Audience (Hazardous Liquid Operators)	**Baseline Message Frequency (starting from elective date of Plan)**
Residents Along Right-of-Way and Places of Congregation	2 years
Emergency Officials	Annual
Public Officials	3 years
Excavator and Contractors	Annual
One-Call Centers	As required of One-Call Center
* Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.	

		S	U	N/A	N/C
.440(g)	The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area.	X			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)	X			
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)	X			
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	X			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (**2 per yr/7½ months**)			X	
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)	X			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:

195.5 - No Conversion to Service in MN.
195.57 - No Offshore pipeline.
195.59 - No Abandoned Underwater pipeline.
195.413(b) - No Gulf of Mexico/inlets.
195.589 - Coupons not used.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	X		
194.111	RSPA Tracking Number: **866** Approval Date: **1/29/08**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	X		
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	X		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the Asequence number.@ It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy ofthe FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existingOPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy ofthe names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Recent PHMSA Advisory Bulletins (Last 2 years)

Leave this list with the operator.

Number	**Date**	**Subject**
ADB-07-01	April 27, 2007	Pipeline Safety: Senior Executive Signature and Certification of Integrity Management Program Performance Reports
ADB-07-02	September 6, 2007	Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-07-02	February 29, 2008	Correction - Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-08-01	May 13, 2008	Pipeline Safety - Notice to Operators of Gas Transmission Pipelines on the Regulatory Status of Direct Sales Pipelines
ADB-08-02	March 4, 2008	Pipeline Safety - Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems
ADB-08-03	March 10, 2008	Pipeline Safety - Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems
ADB-08-04	June 5, 2008	Pipeline Safety - Installation of Excess Flow Valves into Gas Service Lines
ADB-08-05	June 25, 2008	Pipeline Safety - Notice to Hazardous Liquid Pipeline Operators of Request for Voluntary Adv Notification of Intent To Transport Biofuels
ADB-08-06	July 2, 2008	Pipeline Safety - Dynamic Riser Inspection, Maintenance, and Monitoring Records on Offshore Floating Facilities

For more PHMSA Advisory Bulletins, go to http://ops.dot.gov/regs/advise.htm

PHMSA Drug and Alcohol Questions

(To be used in conjunction with other inspections)

Name of Operator Interviewed:	Enbridge Energy Limited Partnership	**Op ID:**	11169
Other Op ID Nos. covered by the above operators D & A Plan:	15774, 31947, 31948, 31448, & 32080		

Any Consortium or Third Party Administrator (C/TPA)		**C/TPA Point of Contact**	
Co. Name:	Pipeline Testing Consortium	**Name:**	Vergie Guerien
Ph. No.:	800-294-8758	**Ph. No.:**	800-294-8758
Address:		**PHMSA (Lead) Representative:**	Brad Ardner
		Date of Inspection:	June 29, 2009

Total number employees performing covered functions (as defined in 199.3) who are under this D & A Plan. Refer to the operator's most recent Management Information System (MIS) report, if available. If it is not available, have the operator provide the information Stanley Kastanas within 14 days if possible.	55 in MN
Total number of operator's (Op. ID Nos. listed above) employees.	55 in MN

Operator's Drug Program Mgr / DER	Truc Lopez	**Phone:**	713-353-6385
Operator Employee Interviewed: Position/Title:	**Mike Goman** Manager, Technical Services	**Phone:**	715-394-1523

Others Present:	Title	Phone No.
Dave Hoffman	**Supervisor, Compliance**	**715-394-1412**
Randy Wilberg	**Safety, Training & Compliance Coordinator**	**715-394-1412**
Patsy Bolk	**Compliance Coordinator**	**715-394-1504**

Interview Questions for the Operator

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes Sat.	No UnSat.
.3 .101 .201 .245	**1. Does the company have a plan for drug and alcohol testing employees performing covered functions?** (i.e., operations, maintenance, or emergency-response as well as verify that their contract employees are also under an appropriate drug and alcohol plan?	X	
Comments:			
.3 .105(c) .225(b)	**2. Does the company perform random drug testing and on-suspicion alcohol testing (unless they are in a FMCSA pool where it's random) of employees performing covered functions? If no to either test, please explain? If yes on drug testing, how many times per year and how many individuals each time?** (Testing must be spread reasonably throughout the calendar year (best practice is at least quarterly and must meet the minimum required annual testing rate, which is currently 25%.)	**X**	
Comments: 25% each calendar year			

PHMSA Drug and Alcohol Questions

(To be used in conjunction with other inspections)

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes Sat.	No UnSat.
.3 .105(b)	**3. Does the company conduct post-accident testing for affected covered function employees following every accident/incident? If no, please explain? If yes, who or whom would be involved in the determination for performing such testing and is there a time limit for making this decision?** (A field supervisor should clearly know if they are responsible for making these decisions.)	X	
Comments: Direct Supervisor/asap but no later than 8 hrs for alcohol or 32 hrs for drugs.			
.113(c) .117(a)(4) .227(b)(2) .241	**4. Does the company provide any training for Supervisors on the detection of potential drug abuse and alcohol misuse? If so, when or how often?** (This applies to reasonable cause/reasonable suspicion determinations. The operator must provide at least 60 minutes of training each on the detection of drug use and alcohol misuse.)	X	
Comments: Within 6 months of becoming a supervisor (min. 60 minutes). Refresher training every three years.			
.3 .113(b) .117(a)(4) .239(b)(11)	**5. Does the company provide an Employee Assistance Program. If so, how are covered ~~function~~ employees made aware of the program, especially on the use of prohibited drugs or alcohol misuse?** (The operator must display and distribute informational material (can be a video), a hotline number, and the operator's policy regarding the use of prohibited drugs.)	X	
Comments: including (Including any of inspector's additional findings/comments)			

Inspector Guidance: Ask the above listed drug and alcohol questions in conjunction with all other inspections or investigations. If the company representative cannot answer a question, please make a note and request the operator provide Stanley Kastanas with the information within 7 business days via e-mail or the telephone number noted below. This should not take more than 15-30 minutes. Do not ask the company to have a drug and alcohol expert available for this portion of your inspection.

The above does not constitute a full drug and alcohol inspection rather it help prioritize companies for PHMSA'a comprehensive drug and alcohol inspection. Please refer the company to Stan Kastanas at 202-550-0629 for any in-depth drug and alcohol questions.

Upon return to your office, please email (scanned if handwritten) this form to Stanley.Kastanas@DOT.GOV.

Note to Inspector: Expanded guidance is posted as a PHP on the Intranet along with a list of operators who have already been interviewed and for whom this form is not required.

Inspectors: An expanded guidance and a list of the operators already surveyed are posted on the PHMSA/OPS SharePoint at: Expanded Guidance for Form 13

OPERATOR QUALIFICATION
FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	June 29 – July 2, 2009
Name of Operator and OPID:	Enbridge Energy Limited Partnership
Inspection Location(s):	Minnesota
Supervisor(s) Contacted:	Dave Hoffman
# Qualified Employees Observed:	1
# Qualified Contractors Observed:	0

Individual Observed	Title/Organization	Phone Number	Email Address
John Bissell	Sr Cathodic Protection Specialist	715-394-1417	John.bissell@enbridge.com

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Brad Ardner	MN	Bradley.ardner@state.mn.us

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is on the last page of this form. This form is to be uploaded on to the OQBD for the appropriate operator, then imported into the file.

9.01 Covered Task Performance

Verify the qualified individuals performed the observed covered tasks in accordance with the operator's procedures or operator approved contractor procedures.

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The employee or contractor individual(s) should be observed performing two separate covered tasks, with only one of the covered tasks being performed as a shop simulation. Obtain a copy of the procedure(s) used to perform the task(s). The individuals should be able to describe key items to be considered for correct performance of the task, and demonstrate strict compliance with procedure requirements. If a crew performing a job is observed (such as installing a service line, tapping a main and supplying gas to a meter set), the individual covered tasks should be identified and documented and the crew member performing the task(s) should be questioned as above.

Additional considerations for covered task observations:

1. Determine if procedures prepared by the operator to conduct the task(s) are present in the field and are being used as necessary to perform the task(s).
2. Confirm that the procedures being used in the field are the same (content, revision number, and/or date issued) as the latest approved procedures in the operator's O&M manual.
3. Confirm that the procedures employed by contractor individuals performing covered tasks are those approved by the operator for the tasks being performed.
4. Ensure that procedure adherence is accomplished and that "work-arounds"[1] are not employed that would invalidate the evaluation and qualification that was performed for the individual in performance of the task.
5. Determine if all of the tools and special equipment identified in procedures are present at the job site and are properly employed in the performance of the task, and if techniques and special processes specified are used as described. In certain circumstances, a contractor may operate the pipeline for an owner/operator. In that case, review which procedures

[1] A "work-around" is a situation where the individual is using a procedure that wouldn't work the way it was written (due to an inadequate procedure or an equipment change that made the procedure steps invalid), or the individual has found a "better" way to get the job done faster instead of using the tool the way it was designed (e.g., not making depth measurements on a tapping tool because you had never drilled through the bottom of the pipe), or not taking the time to follow the manufacturer's instructions (not marking the stab depth when using a Continental coupling to join two sections of plastic pipe) because he never experienced a problem.

have been used to qualify the individuals performing covered tasks and review records accordingly. Also ensure the "operating contractor" performs correct supervisory tasks such as reasonable cause determination.

9.02 Qualification Status

Verify the individuals performing the observed covered tasks are currently qualified to perform the covered tasks.

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The name of each individual observed should be noted and a subsequent review of their qualification records performed to ensure that: 1) the individual was qualified to perform the task observed; and 2) the individual's qualifications are current. A review of the evaluation requirements contained in the operator's or contractor's OQ written program should be performed to ensure that all requirements were met for the current qualification. In addition, a review of the evaluation instruments (written tests, performance evaluation checklists, etc.) may be performed to determine if any of these contain deficiencies (e.g., too few questions to ensure task knowledge, failure to address critical task requirements). Reviews of qualification records and/or evaluation instruments should ensure that AOC evaluation has been performed.

9.03 Abnormal Operating Condition Recognition and Reaction

Verify the individuals performing covered tasks are cognizant of the AOCs that are applicable to the tasks observed.

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: This inspection should focus on an individual's knowledge of the AOCs applicable to the covered task being performed and the ability to recognize and react to those AOCs. The information gained during the inspection should be compared to the requirements for qualification applied by the operator or contractor during the evaluation process for the subject covered task (e.g., knowledge of task-specific AOCs in addition to generic AOCs). If contractor individuals are observed, confirm whether the AOCs identified in the operator's written program are the ones used for qualification of the contractor individual.

9.04 Verification of Qualification

Verify the qualification records are current, and ensure the personal identification of all individuals performing covered tasks are checked, prior to task performance.

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: Supervisors, crew foremen or other persons in charge of field work must be able to verify that the qualifications of individuals performing covered tasks. This typically applies to individuals employed by the operator that are from another district or field office, where the qualification status may be unknown or uncertain, or to contractor individuals. Employee records should be made available through company databases or other means of verification, while contractors should be required to provide documentation of qualification prior to beginning work, and also provide a form of identification that is satisfactory to correlate the qualification documentation with the individual performing the task.

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected at the operational level?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: If the field inspection is performed subsequent to the headquarters inspection (six months or more), the OQ database or inspection records should be checked to determine if any potential issues that were identified as having implications for incorrect task performance (e.g., no skills evaluation for tasks requiring knowledge and skills; hands-on evaluations were performed as a group as opposed to individually; span of control was not specified on a task-specific basis; evaluation and qualification on changed tasks or changed procedures not performed; inadequate provisions for, or inadequate implementation of requirements for, suspension of qualification following involvement in an incident or for reasonable cause) have been corrected.

Field Inspection Notes

The following table is provided for recording the covered tasks observed and the individuals performing those tasks.

No	Task Name	Name/ID of Individual Observed			Comments
		John Bissell			
		Correct Performance (Y/N)	Correct Performance (Y/N)	Correct Performance (Y/N)	
1	Cathodic Protection Readings	Y			
2	Rectifier Maintenance	Y			
3	Electrical Isolation	Y			
4					
5					
6					
7					
8					

PHMSA 2008 Drug and Alcohol Questions
(To be used in conjunction with other inspections)

Name of Operator Interviewed:	Enbridge Energy Limited Partnership	**Op ID:**	11169
Other Op ID Nos. covered by the above operators D & A Plan:	31947, 31395, 31943, 31910, 31944, 31356, 18646, 31426, 32080, 30948, 30946, 31322, 31365, 189		

Any Consortium or Third Party Administrator (C/TPA)		**C/TPA Point of Contact**	
Co. Name:	Pipeline Testing Consortium, Inc	**Name:**	Jeff Martins
Ph. No.:	800-294-8758	**Ph. No.:**	800-294-8758 x405
Address:	9 Compound Drive Hutchinson, KS 67502	**PHMSA (Lead) Representative:**	Carl Griffis
		Date of Inspection:	10/6/08
Total number employees performing covered functions (as defined in 199.3) who are under this D & A Plan. Refer to the operator's most recent Management Information System (MIS) report, if available. If it is not available, have the operator provide the information Stanley Kastanas within 14 days if possible.			1196
Total number of operator's (Op. ID Nos. listed above) employees.			**1929**

Operator's Drug Program Mgr / DER	**Truc Lopez**	**Phone:**	713-353-6385
Operator Employee Interviewed: Position/Title:	**Garry Thompson** **supervisor**	**Phone:**	**219-922-7007**

Others Present:	Title	Phone No.
Jay Johnson	**Senior Compliance Specialist**	**218-390-4711**

Interview Questions for the Operator

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes Sat.	No UnSat.
.3 .101 .201 .245	**1. Does the company have a plan for drug and alcohol testing employees performing covered functions?** (i.e., operations, maintenance, or emergency-response as well as verify that their contract employees are also under an appropriate drug and alcohol plan?	X	
Comments:			
.3 .105(c) .225(b)	**2. Does the company perform random drug testing and on-suspicion alcohol testing (unless they are in a FMCSA pool where it's random) of employees performing covered functions? If no to either test, please explain? If yes on drug testing, how many times per year and how many individuals each time?** (Testing must be spread reasonably throughout the calendar year (best practice is at least quarterly and must meet the minimum required annual testing rate, which is currently 25%.)	**X**	
Comments: Random tests are performed quarterly with 25% of employees in the random pool.			

PHMSA 2008 Drug and Alcohol Questions

(To be used in conjunction with other inspections)

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes Sat.	No UnSat.
.3 .105(b)	**3. Does the company conduct post-accident testing for affected covered function employees following every accident/incident? If no, please explain? If yes, who or whom would be involved in the determination for performing such testing and is there a time limit for making this decision?** (A field supervisor should clearly know if they are responsible for making these decisions.)	X	
Comments: Post accident tests are done automatically if they meet the definition of a DOT incident. Otherwise, the manager/supervisors determine if tests should be done based on individual cases.			
.113(c) .117(a)(4) .227(b)(2) .241	**4. Does the company provide any training for Supervisors on the detection of potential drug abuse and alcohol misuse? If so, when or how often?** (This applies to reasonable cause/reasonable suspicion determinations. The operator must provide at least 60 minutes of training each on the detection of drug use and alcohol misuse.)	X	
Comments:			
.3 .113(b) .117(a)(4) .239(b)(11)	**5. Does the company provide an Employee Assistance Program. If so, how are covered function employees made aware of the program, especially on the use of prohibited drugs or alcohol misuse?** (The operator must display and distribute informational material (can be a video), a hotline number, and the operator's policy regarding the use of prohibited drugs.)	X	
Comments: including (Including any of inspector's additional findings/comments) Guidelines are provided in the Company's Anti-Drug and Alcohol Prevention Plans and in the Company's Anit-Drug Policy regarding the availability of the EAP.			

Inspector Guidance: Ask the above listed drug and alcohol questions in conjunction with all other inspections or investigations. If the company representative cannot answer a question, please make a note and request the operator provide Stanley Kastanas with the information within 7 business days via e-mail or the telephone number noted below. This should not take more than 15-30 minutes. Do not ask the company to have a drug and alcohol expert available for this portion of your inspection.

The above does not constitute a full drug and alcohol inspection rather it help prioritize companies for PHMSA'a comprehensive drug and alcohol inspection. Please refer the company to Stan Kastanas at 202-550-0629 for any in-depth drug and alcohol questions.

Upon return to your office, please email (scanned if handwritten) this form to Stanley.Kastanas@DOT.GOV.

Note to Inspector: Expanded guidance is posted as a PHP on the Intranet along with a list of operators who have already been interviewed and for whom this form is not required.

An expanded guidance and a list of the operators already surveyed are posted on the PHMSA/OPS Intranet at: http://opsintranet.phmsa.dot.gov/Manual/Volume3/enforcement_guidelines.htm

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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 02/04/2009	**Inspector/Submit Date:** Brian Pierzina 02/04/2009
		Peer Reviewer/Date: 2-10-09
		Director Approval for 2/20/09

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:	Interstate Hazardous Liquid – Crude Oil	
Inspection Type:	Construction, Design, Testing Inspection 450	**Inspection Date(s):** 4/3,4/2008
For OPS :		**AFO Days:**
For MNOPS :	Brian Pierzina	**AFO Days:** (2)
MNOPS CASE #: 7930		

Synopsis: This case relates to an Enbridge corrosion anomaly dig on the 34 inch Line 3 at MP 1008, near the Grand Rapids High School. Enbridge discovered unreported damage from a cable installation project, along with an 82% deep corrosion pit, not associated with the damage. The pipeline was repaired with tight fitting sleeves. No violations identified.

Summary:

4/2/08

Brian Pierzina arrived on site and met Craig Goplin, Enbridge Project Coordinator and Lowell Learn, Enbridge Inspector. Surveyed activities, coating was still being removed. Enbridge discovered during the excavation that the pipeline had been gouged during a prior cable installation project. They were able to determine the damage occurred during a 1993 installation. The scratch/gouge is approximately 12 feet long. Depth assessment will be performed after the sand blasting is completed. The cable was installed by Itasca Utilities. Andy MacDonnell, owner of Itasca Utilities was on site to look at the damage, but he was still in High School when this cable was installed.

The corrosion indication being investigated was called out as 30 inches long, with a peak depth of 76%. Review of the feature report did not reveal any indication meeting those dimensions. The specific feature at 14.82 feet, was called out as 5 inches long, with a peak depth of 33%, although there were approximately 20 individual features reported for this location. All reported features are at or near 6:00. Long seam orientation is approximately 1:00. The pipe joint (13666) is 20 feet long, in between two forty 40 joints.

Sandblasting will take place until early afternoon, before the NDT can be performed. Mike Miller, from Pfinde will be the NDT technician.

Reviewed and signed the Enbridge Safe Work Permit, and reviewed OQ records for the Casper Construction crew, which included others that were not on site. Several of the crew's qualifications are scheduled to expire in July of 2008. No issues were identified. The excavation site looked very good. Traffic control was necessary, as they needed to cut a portion of the road (16th St NW).

BEP PM Observations
Following sandblasting, it was clear that the external corrosion extended upstream beyond where the tape had been removed, so additional pipe needed to be cleaned. The deepest corrosion pit on the bottom of the pipe was .230 inches in the .281 inch wall pipe, or 82% deep. The pit, however, was only about 1 inch in diameter. Magnetic particle examination is now being conducted on the corrosion areas, long seams, girth welds, and the mechanical damage that resulted from the prior cable installation.

4/4/08 BEP AM
Arrived on site and met Lowell Learn. He mentioned there had been a change in plans, as they were initially planning to begin sleeving operations on Monday morning, but due to the depth of the pit, they decided they would begin sleeving immediately. The overall sleeve length will be 25 to 26 feet, extending about one foot beyond the girth weld upstream, and about four feet beyond the girth weld downstream (20 foot pipe joint).

The crew had mentioned a slightly different soil type had been found adjacent to the pipe, which was more clay like. Most of the soil was sandy gravel. They saved a sample of it, in case some soil analysis can be done to help evaluate the corrosion.

Images were forwarded to PHMSA Central Region on 04/04/2008. No violations were identified. No further actions are anticipated with respect to this Case.

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Post Inspection Memorandum (PIM)

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Inspection Report		Post Inspection Memorandum
Inspector/Submit Date:	Brian Pierzina 02/09/2009	**Inspector/Submit Date:** Brian Pierzina 02/09/2009
		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:	Right-of-Way	**Inspection Date(s):** 02/04/2008	
For OPS :		**AFO Days:**	
For MNOPS :	Boyd Haugrose	**AFO Days:** (1)	
MNOPS CASE #: 7822			

Synopsis: On January 10, 2008, MNOPS received a complaint from Larry Westrum, a landowner near Clearbrook, MN, who owns property in which Enbridge has pipelines passing through. Three of the four pipelines running through Mr. Westrum's property are exposed. He has concerns specifically related to the 34 inch Line 3, which has deteriorated coating, and has had two prior releases on his property. On February 4, 2008, Boyd Haugrose met with Mr. Westrum at his home to discuss his concerns. The recent releases at MP 912, which is just upstream from his property, had heightened his anxiety concerning safety associated with the pipelines. Brian Pierzina followed up verbally with Mr. Westrum and Enbridge representatives in October 2008. According to Karen Johnson – Enbridge ROW - Bemidji, Enbridge is planning to mitigate the situation during 2009.

Summary: 1/10/2008 - 10:45 AM (PJD) Landowner Larry Westrum called stating that he had an exposed pipeline on land. Larry stated the pipe is bare and has no wrap on it. During the conversation Larry stated that Enbridge has had two spills on his land and the company knows that the line is exposed, but will not do anything about it.

PJD told Larry that he would have an inspector in northern MN follow-up with him.

Larry Westrum
45236 221st Ave
Leonard, MN 56652-4136
(218) 968-2212

2/4/08
BEH interviewed Mr. Westrum at his home. This is the site of a release from the EEC line 4, 34" pipeline on July 22, 2000. The release was that from a cracked horizontal weld on a tight fitting repair sleeve installed in 1998. The release was from such a location that the pipe was partially submerged in swamp waters that surround Ruffy Brook, a native trout stream. The DNR allowed EEC to burn the surface of the wetlands as part of the recovery. The pipeline that leaked and the one not exposed are located on the north side of his house. The two lines that lay on the surface are on the south side of his buildings.

Mr. Westrum states he has spoken with EEC personnel numerous times and has asked for the lines to be lowered. To access his property with farm machinery he had to drive over one of the lines for years. EEC did finally pile dirt over this line so that he could traverse over it. This location is two miles downstream of the incidents at MP 912 in November, 2007.

10/08/08 BEP
Left messages with Karen Johnson (Enbridge ROW Agent) and the Westrum residence to determine the current status of the complaint. Karen is on vacation until October 15th. Spoke with Mark Olson, in Superior. He said he would try to find out, but thought that Karen would be the one who would be most familiar.

02/02/09 BEP
In speaking with Mr. Westrum, Karen Johnson and Mark Olson it appears the parties are having continuing discussions to resolve Mr. Westrum's concerns. Enbridge has plans to mitigate the coating problems during 2009. It does not appear that further MNOPS involvement with respect to this Case will be necessary at this time.

TALKED TO B. Piersma,
They will keep this case open for follow-up to ensure the Enbridge follows up and fixes the issues

LLS

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

November 3, 2007

Mr. Darren Lemmerman
Acting Chief Engineer
Minnesota Department of Public Safety
444 Cedar Street, Suite 147
St. Paul, MN 55101

Re: Interstate Agent Activities – Enbridge Energy, Limited Partners; Field and Records Inspection – August 6-10, 2007; September 24-28, 2007

Dear Mr. Lemmerman:

The Pipeline and Hazardous Materials Safety Administration, Central Region (PHMSA), is in receipt of the Minnesota Office of Pipeline Safety (MNOPS) report dated September 5, 2007 and October 26, 2007 concerning an inspection conducted on Enbridge Energy, LP.

The inspection report was submitted in your capacity as Interstate Agent for PHMSA. The following issues were noted during your staff's inspection:

1) Review of the 2005 Annual Report indicated that there was 190 miles of HVL pipeline in total. This only included the 18 inch from Clearbrook to Superior. There is nothing reported for the HVL pipeline upstream of Clearbrook, even though the 20 inch is predominantly NGL from the Canadian Border to Clearbrook. Follow-up from Enbridge found that the 20" should have been reported with the HVL mileage, instead of being reported with the crude oil mileage.

2) The test station MP 1035.483 where 18 and 26 inch lines are indicated as winter reads, did not have a 2005 or 2006 reading. Additionally, the test station at MP 1043.064 did not have a 2005 or 2006 reading.

3) The exposed mainlines at the Necktie River, MP 913, and irrigation ditches MP 797, and MP 829 (Tamarac River) did not have an atmospheric corrosion inspection done on them.

4) At the exposed Necktie River Crossing, there were no markers at the river crossing or within a half mile of the river crossing.

These issues have been noted by PHMSA, and we will take action on these issues and any others noted in your post-inspection memo.

We will provide you with a copy of the document when completed.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

cc: Brian Pierzina – MNOPS
Leonard Steiner - PHMSA

COPIES ALSO SENT 11/1/07 TO:

Initiating Engineer, Hans Shieh

Read File

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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: ______________	**Inspector/Submit Date:** ______________ **Peer Review/Date:** ______________ **Director Approval/Date:**

POST INSPECTION MEMORANDUM (PIM)	
Name of Operator: Enbridge Energy, Limited Partners	**OPID #:** 11169
Name of Unit(s): North Dakota	**Unit # (s):** 16123
Records Location: Superior, WI	
Unit Type & Commodity: Interstate Liquid; Crude Oil and HVLs	
Inspection Type: Standard	**Inspection Date(s):** 8/6-10/07; 9/24-28/07
PHMSA Representative(s): H.Shieh	**AFO Days:** 7

Summary:

Hans Shieh conducted a standard inspection of the Enbridge North Dakota unit. Records were looked at in Superior, WI with Brian Pierzina and Boyd Haugrose of the MNOPS. The field work consisted of running the lines from the Canadian border to the ND/MN border. Numerous CP readings were taken and several rectifiers were checked. Additionally, the pump station at Joliette was evaluated. A couple of valves were operated and an above-ground exposure was looked at.

Findings:

The records review for this unit revealed two issues.....

1) The exposures at MP 797 and 829 were not checked for atmospheric corrosion in 2006.

2) The T.S at MP 831.065 was not read in 2005 or 2006 because of a bad test lead.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: Enbridge Energy, Limited Partners	
OP ID No. [1] 11169	**Unit ID No.** [1] 16123
H.Q. Address:	**System/Unit Name & Address:** [1]
1100 Louisiana Suite 3300 Houston, TX 77002	
Co. Official: Mr. Terry McGill - President	**Activity Record ID#:** 119029
Phone No.: 713-821-0003	**Phone No.:**
Fax No.: 713-821-2080	**Fax No.:**
Emergency Phone No.: 800-858-5253	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Patsy Bolk	Compliance Analyst	
Randy Wilberg	Safety/Compliance - Superior Region	
Mike Goman	Supr -Superior Region	
Jay Johnson	Sr. Compliance Coordinator	
Mark Willoughby	GM - Superior Region	
Donna Tribe	Compliance - Edmonton	
Charmaine Rosenbaum	Manager - Human Resources	
Patricia Nettleton	Payroll Coordinator	
Jeff Martin	PTC	
Gail Follis	Tech Records Coordinator	
Cynthia Clark	OQ training Coordinator	
Bill Bock	Enbridge Supervisor - Controls	
Jarrett Kachur	Enbridge Facilities Management	
Tony Hommerding	PLM Superior	
Jim Johnston	Edmonton Control Center	
Nori Ferris	Safety and environmental Clerk	
Tom Peterson	Maximo Coordinator	
John Bissell	Sr. CP Specialist	
Mark Jerabeh	Sr. Comm. Cord.	
Trevor Place	Corrosion Eng. Edmonton	

PHMSA Representative(s) [1] H. Shieh **Inspection Date(s)** [1] 8/6-10/2007, 9/23-24/2007

Company System Maps (copies for Region Files): Yes

Unit Description:
18", 26", 34" and 48" lines from MP 773.72 (Canadian / US Border) - MP 801.73 (ND / MN border at the Red River).

Portion of Unit Inspected [1]

The entire unit was inspected.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/02/02 and 03/02/07.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	CONVERSION TO SERVICE	S	U	N/A	N/C
* .5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				X
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
Team O&M conducted in May of 2006.

		SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
Team O&M conducted in May of 2006.

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				X
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				X
		Welding procedures must be qualified by destructive testing.				X
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2004 Ed. Including addenda through July 1, 2005), except that a welder qualified under an earlier edition than listed in **' 195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 195-81 corr. Pub. 9/09/04; Amt 195-86 pub 06/09/06 eff 07/10/06.				X
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				X
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				X
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				X
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **' 195.228(b)** and per the requirements of **' 195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				X
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				X
		2. By qualified personnel				X
		3. By a process that will indicate any defects that may affect the integrity of the weld				X
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				X
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				X

Comments:
Team O&M conducted in May of 2006.

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.302(a)	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions).				X
	.302(b)	Except for lines converted under **' 195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				X
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in ' 195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				X
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				X
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				X
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with **' 195.302.**				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:
Team O&M conducted in May of 2006.

		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				X
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				X
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				X

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		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **' 195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				X
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **' 195.406**?				X
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **' 195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				X
	.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				X
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59.				X
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				X
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				X
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				X
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				X

Comments:
Team O&M conducted in May of 2006.

		ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				X
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				X
		iii. Loss of communications?				X
		iv. The operation of any safety device?				X
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				X
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:
Team O&M conducted in May of 2006.

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		EMERGENCY PROCEDURES	S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:
Team O&M conducted in May of 2006.

		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				X
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				X
	.403(b)(2)	Make appropriate changes to the emergency response training program				X
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				X

Comments:
Team O&M conducted in May of 2006.

		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				X

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		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				X
		ii. Pump stations				X
		iii. Scraper and sphere facilities				X
		iv. Pipeline valves				X
		v. Facilities to which ' **195.402(c)(9)** applies				X
		vi. Rights-of-way				X
		vii. Safety devices to which ' **195.428** applies				X
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				X
	.404(a)(3)	The maximum operating pressure of each pipeline.				X
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				X
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				X
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under ' **195.402** apply.				X
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				X
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				X
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.				X

Comments:
Team O&M conducted in May of 2006.

		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	**.406(a)**	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	**.406(a)(1)**	The internal design pressure of the pipe determined by ' **195.106**. Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	**80%** of the test pressure (**Subpart E**).				X
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
Team O&M conducted in May of 2006.

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COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **' 195.402(c)(9).**				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
Team O&M conducted in May of 2006.

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
Team O&M conducted in May of 2006.

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				X
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 **years**.				X

Comments:
Team O&M conducted in May of 2006.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				X
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X

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UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				X

Comments:
Team O&M conducted in May of 2006.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				X
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **72 months**, but at least **twice** each calendar year.				X
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				X

Comments:
. Team O&M conducted in May of 2006.

PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
Team O&M conducted in May of 2006.

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
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SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C

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SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:
Team O&M conducted in May of 2006.

OVERPRESSURE SAFETY DEVICE PROCEDURES			S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				X
		2. **HVL** pipelines at intervals not to exceed **72 months**, but at least **twice** each calendar year.				X
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				X
*	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Amt 195-86 pub 06/09/06 eff 07/10/06. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				X
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				X

Comments:
Team O&M conducted in May of 2006.

FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				X
		The equipment must be:				
		a. In proper operating condition at all times.				X
		b. Plainly marked so that its identity as firefighting equipment is clear.				X
		c. Located so that it is easily accessible during a fire.				X

Comments:
Team O&M conducted in May of 2006.

BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				X

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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **' 195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				X
*	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
Team O&M conducted in May of 2006.

		SIGN PROCEDURES	S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
*		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
Team O&M conducted in May of 2006.

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:
Team O&M conducted in May of 2006.

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				X

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Comments:
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DAMAGE PREVENTION PROGRAM PROCEDURES			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				X
	.442(b)	Does the operator participate in a qualified One-Call program?				X
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				X
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph **(c)(1)** of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				X
		ii. How to learn the location of underground pipelines before excavation activities are begun.				X
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				X
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				X
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				X
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				X
		ii. In the case of blasting, any inspection must include leakage surveys.				X

Comments:
Team O&M conducted in May of 2006.

CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
.402(a) *	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

SUBPART H - CORROSION CONTROL PROCEDURES			S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X
*	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2002** (incorporated by reference). Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**.				X
		Separately protected short sections of bare ineffectively coated pipelines (**every 3 years not to exceed 39 months**).				X
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-2002.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				X
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				X
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 22 mos.**				X
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				X
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				X
	.575	Are there adequate provisions for electrical isolations?				X
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				X
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				X
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				X
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 2 months.**				X
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				X
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				X
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				X
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				X
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				X
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				X
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**				X
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - FIELD REVIEW		S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory			X	
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers	X			
.412	ROW/Crossing Under Navigable Waters	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings - Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks			X	
.434	Signs - Pumping Stations - Breakout Tanks			X	
.436	Security - Pumping Stations - Breakout Tanks			X	
.438	No Smoking Signs	X			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form				X
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.575	Electrical Isolation; shorted casings	X			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)	X			

Comments:

.308 was marked "n/c" because they did not have an pre-tested pipe in this unit.
.432-.436 was marked N/A because they do not have an B.O. Tanks in this unit.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	X			
.52	Telephonic Reports to NRC (800-424-8802)				X
.54(a)	Written Accident Reports (DOT Form 7000-1)				X
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)				X
.56	Safety Related Conditions				X
.57	Offshore Pipeline Condition Reports			X	
.59	Abandoned Underwater Facility Reports			X	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification			X	
.214(b)	Test Results to Qualify Welding Procedures			X	
.222	Welder Qualification			X	
.234(b)	Nondestructive Technician Qualification			X	
.589	Cathodic Protection			X	
.266	Construction Records			X	
.266(a)	Total Number of Girth Welds			X	
	Number of Welds Inspected by NDT			X	
	Number of Welds Rejected			X	
	Disposition of each Weld Rejected			X	
.266(b)	Amount, Location, Cover of each Size of Pipe Installed			X	
.266(c)	Location of each Crossing with another Pipeline			X	
.266(d)	Location of each buried Utility Crossing			X	
.266(e)	Location of Overhead Crossings			X	
.266(f)	Location of each Valve and Test Station			X	
	PRESSURE TESTING				
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.308	Records of Pre-tested Pipe	X			
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities			X	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)				
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			X	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)			X	
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).			X	
.440	Public Education/Awareness Program	X			
DAMAGE PREVENTION PROGRAM					

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
CORROSION CONTROL					
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests **(1 per yr/15 months)**		X		
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas **(1 per 3 cal yr/39 months)**			X	
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers			X	
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks			X	
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment **(2 per yr/7½ months)**	X			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**		X		
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:

.5(a)(2) & .5(c) were marked "N/A" because they did not do any conversion of service.

.52, .54(a), .54(b), .56 were marked "N/C" because those were reviewed at the office.

.57 and .59 were marked "N/A" because they do not have any off shore facilities in this unit, nor did they abandon any pipe in a navigable waterway.

.204-.266(f) was marked "N/A" because there has been no construction on the ND unit.

.402(c)(10) was marked "N/A" because they have not abandoned any facilities.

.413(b) was marked "N/A" because they do not have facilities in the Gulf of Mexico in this unit.

.428(b) was marked "N/A" because they do not have any relief devices on HVL tanks.

.428(d) was marked "N/A" because they do not have any B.O. tanks in this unit.

.432 was marked "N/A" because they do not have any B.O. tanks in this unit.

.573(a)(1) was marked "U" because at MP 831.065, they did not get a read because of no test lead for 2005 and 2006. There was a reading in 2004.

.573(b), .573(c), .573(d) were marked "N/A" because they do not have unprotected pipe, bonds, or B.O. Tanks in this unit.

.583(a) was marked "U" because they did not atmospherically check the exposures at MP 797 and 829 for 2006.

	Field Verification of Facility Response Plan Information	Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	X		
	RSPA Tracking Number: **866,867,1666,665,70 1702** Approval Date: **February 95**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	X		
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	X		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*
Enbridge has just sent in revisions dated 7/18/2007.

OPA Inspection Guidance

OPA-1 - **RSPA Tracking Number**: This is also known as the Asequence number.@ It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - **Names and phone numbers**: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - **Proof of OSRO contract**: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - **Exercise documentation**: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - **Training records**: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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:	Brian Pierzina/Carl Griffis – 12/18/2009
Inspector/Submit Date:	Brian Pierzina/Carl Griffis – 12/18/2009	**Peer Review/Date:**	B. Dahn / 12/18/09
		Director Approval/Date:	[illegible] 1/17/10

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy, Limited Partnership	**OPID #:**	11169
Name of Unit(s):	Griffith	**Unit # (s):**	12823
Records Location:	Griffith, IN		
Unit Type & Commodity:	Interstate Hazardous Liquid (A1) - Crude Oil		
Inspection Type:	Standard	**Inspection Date(s):**	10/06-10/08, 10/28/08, 1/21-22/09
PHMSA Representative(s):	Carl Griffis	**AFO Days:**	7.0

Summary:

A standard inspection of the Enbridge Energy, Limited Partnership, Griffith, IN unit was performed, including a field inspection and records inspections. An Operations &Maintenance (O & M) Manual inspection was not performed since the last team O&M was performed in May 2006.

Findings:

195.579(b) Line 6B is injected with corrosion inhibitor, yet internal coupons or other monitoring equipment have not been evaluated since October 2007. See attachments for corrosion monitoring record and explanation from Enbridge why the corrosion monitoring equipment or coupons are not in use.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: Enbridge Energy Limited Partnership	
OP ID No. [1] 11169	**Unit ID No.** [1] 12823
H.Q. Address:	**System/Unit Name & Address:** [1]
1100 Louisiana Suite 3300 Houston, TX 77002	Griffith 1500 West Main Street Griffith, IN 46319
Co. Official: Terry McGill, President	**Activity Record ID#:** 120427
Phone No.: 713-821-8003	**Phone No.:** 219-922-3133
Fax No.:	**Fax No.:** 219-924-6463
Emergency Phone No.: 888-427-7777	**Emergency Phone No.:** 888-427-7777

Persons Interviewed	Titles	Phone No.
German Meiendre	Engineer Ocens (Enbridge)	5-7-1-3250250
Bryan Christ	Safety Coordinator	219-775-7315
Jay Johnson	Senior Compliance Specialist	218-390-4711
Brad Salo	Compliance Coordinator	218-335-8337
Jerry Dewitt	Corrosion Specialist	219-5763164
Tom Peterson	Maximo Coordinator	715-394-1424
Shelly Cornell	One Call Dispatcher	219-922-7036
Mark Varichzk	Region Engineer	219-922-7021
Garry Thompson	Supervisor	219-922-7007
Jim Sweeney	Operations Coordinator	219-922-7020
James Schwartz	Chief, MBF (contractor)	970-520-2543
Trevor Place	Senior Engineer	780-420-8494
Dean Rawson	Manager, Tech. Services	219-922-7003
Steve Ott	Technical Supervisor	920-563-6648
Mike Lange	Electrical Technician	847-428-6960
Glen Morgan	Corrosion Specialist (contractor)	630-399-4660

PHMSA Representative(s) [1] **Carl Griffis** **Inspection Date(s)** [1] **10/06-10/08, 10/28/08, 1/21-22/09**

Company System Maps (copies for Region Files): attached

Unit Description:
34" pipeline #6A from MP 385.99 (south of Dundee, IL) to MP 465.38 (Griffith). 30" pipeline #6B from MP 465.38 (Griffith, IN) to MP 519.96 (Timothy Road centerline in New Carlisle, IN). Line 14 from MP 438.40 (Mokena, IL Station) to MP 384.00 (Burlington Station, WI). This inspection does not include the Burlington Station, WI unit. Burlington Station, WI is in the Fort Atkinson, WI unit. This unit also includes the Griffith Lateral, Line 64 - 26 Miles Of 24" pipeline starting at MP 455.5 of pipeline #14 and traveling east, paralleling pipeline #6A at MP 444.2 into the Griffith Terminal MP 465. This unit also includes Stage II of Southern Access/Southern Lights pipeline. Southern Access consists of 133 Miles of 42" pipeline from the Delavan, WI pump station to Flanagan, IL. Southern Lights consists of 153 Miles of 20" pipeline that parallels the 42" Southern Access pipeline from Delavan, WI to Streator, IL, at which point the 20" pipeline turns east and terminates at Manhattan, IL.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Portion of Unit Inspected [1]
Various locations on pipelines #6A, #6B, #14, and #64 were inspected. Cathodic protection readings and proper valve operation was verified. See the field inspection form for field inspection details.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/07/03 and 03/07/08.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

CONVERSION TO SERVICE			S	U	N/A	N/C
*	.5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				✓
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				✓
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				✓
	.54(b)	Supplemental report - required within 30 days of information change/addition				✓
	.55	Safety-related conditions (SRC) - criteria				✓
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				✓
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				✓
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				✓
		Welding procedures must be qualified by destructive testing.				✓
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				✓

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2004 Ed. Including addenda through July 1, 2005), except that a welder qualified under an earlier edition than listed in **' 195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 195-81 corr. Pub. 9/09/04; Amt 195-86 pub 06/09/06 eff 07/10/06.				✓
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				✓
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				✓
	.226(b)	If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed. Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate).**				✓
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				✓
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **' 195.228(b)** and per the requirements of **' 195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				✓
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				✓
		2. By qualified personnel				✓
		3. By a process that will indicate any defects that may affect the integrity of the weld				✓
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				✓
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), .303, and .305(b) for exceptions).				✓

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		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
	.302(b)/ .302(c)	Except for lines converted under ' 195.5, the following pipelines may be operated without having been pressure tested per Subpart E and without having established MOP under 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure]. - .302(b)(2)(ii): Any carbon dioxide pipeline constructed before July 12, 1991, that is located in a rural area as part of a production field distribution system. - .302(b)(3): Any low-stress pipeline constructed before August 11, 1994, that does not transport HVL. - .302(b)(4)/.303: Those portions of older hazardous liquid and carbon dioxide pipelines for which an operator has elected the risk-based alternative under §195.303 and which are not required to be tested based on the risk-based criteria.				
		Have pipelines <u>other than those described above</u> been pressure tested per Subpart E?				✓
		If pipelines <u>other than those described above</u> have not been pressure tested per Subpart E, has MOP been established under 195.406(a)(5), in accordance with .302(c)? Note: Establishing MOP under 195.406(a)(5) only applies to specified "older" pipelines constructed prior to the dates in .302(b).				✓
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				✓
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with ' **195.302.**				✓
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				✓
	.306	Appropriate test medium				✓
	.308	Pipe associated with tie-ins must be pressure tested.				✓
	.310(a)	Test records must be retained for useful life of the facility.				✓
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				✓
	.310(b)(2)	Test instrument calibration data.				✓
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				✓
	.310(b)(4)	Date and time of the test.				✓
	.310(b)(5)	Minimum test pressure.				✓
	.310(b)(6)	Test medium.				✓
	.310(b)(7)	Description of the facility tested and the test apparatus.				✓
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				✓
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				✓
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				✓

Comments:

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SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES				S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				✓
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				✓
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				✓
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				✓
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				✓
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **' 195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				✓
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **' 195.406**?				✓
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **' 195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				✓
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				✓
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59.				✓
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				✓
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				✓
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				✓
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				✓
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				✓
		iii. Loss of communications?				✓
		iv. The operation of any safety device?				✓
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				✓
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				✓
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				✓
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				✓
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				✓
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				✓
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				✓
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				✓
	.402(e)(5)	Controlling the release of liquid at the failure site?				✓
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				✓
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				✓
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				✓
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				✓

Comments:
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EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				✓
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				✓
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				✓
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				✓
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				✓
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				✓
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				✓
	.403(b)(2)	Make appropriate changes to the emergency response training program				✓
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				✓
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				✓
		ii. Pump stations				✓
		iii. Scraper and sphere facilities				✓
		iv. Pipeline valves				✓
		v. Facilities to which **' 195.402(c)(9)** applies				✓
		vi. Rights-of-way				✓
		vii. Safety devices to which **' 195.428** applies				✓
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				✓
	.404(a)(3)	The maximum operating pressure of each pipeline.				✓
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				✓
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				✓
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under **' 195.402** apply.				✓
	.404(c)	Each operator shall maintain the following records for the periods specified:				

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		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				✓
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				✓
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	.406(a)(1)	The internal design pressure of the pipe determined by **' 195.106**. Amt 195-86 pub 06/09/06 eff 07/10/06.				✓
	.406(a)(2)	The design pressure of any other component on the pipeline.				✓
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				✓
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				✓
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				✓
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				✓
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				✓
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **' 195.402(c)(9)**.				✓
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				✓
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				✓
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				✓

Comments:
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		LINE MARKER PROCEDURES	S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				✓
	.410(a)(2)	Must have the correct characteristics and information				✓
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES	S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				✓
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 years.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES	S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				✓
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				✓
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				✓
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				✓
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				✓
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				✓

Comments:
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VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				✓
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7 ½ months**, but at least **twice** each calendar year.				✓
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				✓
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				✓
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				✓
	.424(b)(2)	Have procedures under **' 195.402** containing precautions to protect the public.				✓
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				✓
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				✓
	.424(c)(2)	Have procedures under **' 195.402** containing precautions to protect the public.				✓
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				✓
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				✓

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
The last Team O&M inspection was conducted in May of 2006.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				✓
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				✓
		2. **HVL** pipelines at intervals not to exceed **7 ½ months**, but at least **twice** each calendar year.				✓
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding 5 years.				✓
*	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Amt 195-86 pub 06/09/06 eff 07/10/06. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				✓
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				✓
		The equipment must be:				
		a. In proper operating condition at all times.				✓
		b. Plainly marked so that its identity as firefighting equipment is clear.				✓
		c. Located so that it is easily accessible during a fire.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				✓

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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **' 195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				✓
*	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.** Amt 195-86 pub 06/09/06 eff 07/10/06.				✓
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				✓
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
The last Team O&M inspection was conducted in May of 2006.

		SIGN PROCEDURES	S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				✓
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		SECURITY of FACILITY PROCEDURES	S	U	N/A	~~N/C~~
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				✓

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
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		PUBLIC AWARENESS PROGRAM PROCEDURES (In accordance with API RP 1162)	S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program also in accordance with API RP 1162 (Amdt 192-83 pub. 5/19/05 eff. 06/20/05) The Clearinghouse recently reviewed the procedures applicable to API 1162.				
*	.440(d)	The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				
		(1) Use of a one-call notification system prior to excavation and other damage prevention activities;				✓
		(2) Possible hazards associated with unintended releases from a hazardous liquids or carbon dioxide pipeline facility;				✓
		(3) Physical indications of a possible release;				✓
		(4) Steps to be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; and				✓
		(5) Procedures to report such an event (to the operator).				✓
*	.440(e)	The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				✓
*	.440(f)	The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports hazardous liquid or carbon dioxide. Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				✓
*	.440(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area. Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API RP 1162)	S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				✓
	.442(b)	Does the operator participate in a qualified One-Call program?				✓
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				✓
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				✓
		ii. How to learn the location of underground pipelines before excavation activities are begun.				✓
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				✓
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				✓
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				✓

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API RP 1162)	S	U	N/A	N/C
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				✓
		ii. In the case of blasting, any inspection must include leakage surveys.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a) *	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training? Amt 195-86 pub 06/09/06 eff 07/10/06.				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

	PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES	S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

	SUBPART G - OPERATOR QUALIFICATION PROCEDURES	S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				✓
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				✓
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				✓
		2) Is a segment that is relocated, replaced, or substantially altered?				✓

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				✓
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				✓
		b. All coating damage discovered must be repaired.				✓
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				✓
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				✓
		2) Is a segment that is relocated, replaced, or substantially altered?				✓
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				✓
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				✓
		e. Unprotected pipe must have cathodic protection if required by **195.573(b).**				✓
	.567	Test leads installation and maintenance.				✓
	.569	Examination of Exposed Portions of Buried Pipelines.				✓
*	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2002** (incorporated by reference). Amt 195-86 pub 06/09/06 eff 07/10/06.				✓
	.573	a. (1) Pipe to soil monitoring **(annually / 15months).**				✓
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months).**				✓
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-2002.** Amt 195-86 pub 06/09/06 eff 07/10/06.				✓
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				✓
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				✓
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2 ½ mos.**				✓
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				✓

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				✓
	.575	Are there adequate provisions for electrical isolations?				✓
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				✓
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				✓
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				✓
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**				✓
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				✓
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				✓
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				✓
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				✓
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				✓
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				✓
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**				✓
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				✓

Comments:
The last Team O&M inspection was conducted in May of 2006.

PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES		S	U	N/A	N/C
Subparts A - C	Drug & Alcohol Testing & Alcohol Misuse Prevention Program – Use PHMSA Form # 13, PHMSA 2008 Drug and Alcohol Program Check.				

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.262	Pumping Stations	✓			
.262	Station Safety Devices	✓			
.308	Pre-pressure Testing Pipe - Marking and Inventory	✓			
.403	Supervisor Knowledge of Emergency Response Procedures	✓			
.410	Right-of-Way Markers	✓			
.412	ROW/Crossing Under Navigable Waters	✓			
.420	Valve Maintenance	✓			
.420	Valve Protection from Unauthorized Operation and Vandalism	✓			

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	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.426	Scraper and Sphere Facilities and Launchers	✓			
.428	Pressure Limiting Devices	✓			
.428	Relief Valves - Location - Pressure Settings - Maintenance	✓			
.428	Pressure Controllers	✓			
.430	Fire Fighting Equipment	✓			
.432	Breakout Tanks	✓			
.434	Signs - Pumping Stations - Breakout Tanks	✓			
.436	Security - Pumping Stations - Breakout Tanks	✓			
.438	No Smoking Signs	✓			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form ***Field OQ Inspection not performed during this inspection***				✓
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	✓			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	✓			
.575	Electrical Isolation; shorted casings	✓			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)	✓			

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline. ***No facilities converted***				✓
.5(c)	Pipeline Records (Life of System)				✓
	Pipeline Investigations				✓
	Pipeline Testing				✓
	Pipeline Repairs				✓
	Pipeline Replacements				✓
	Pipeline Alterations				✓
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	✓			
.52	Telephonic Reports to NRC (800-424-8802)	✓			
.54(a)	Written Accident Reports (DOT Form 7000-1)	✓			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	✓			
.56	Safety Related Conditions ***no reports filed***			✓	
.57	Offshore Pipeline Condition Reports ***no facilities***			✓	
.59	Abandoned Underwater Facility Reports ***no facilities***			✓	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	✓			
.214(b)	Test Results to Qualify Welding Procedures	✓			

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.222	Welder Qualification *checked tank and pipe welders*	✓			
.234(b)	Nondestructive Technician Qualification	✓			
.589	Cathodic Protection	✓			
.266	Construction Records	✓			
.266(a)	Total Number of Girth Welds *tank construction at Griffith Terminal Tanks 79, 80*	✓			
	Number of Welds Inspected by NDT	✓			
	Number of Welds Rejected	✓			
	Disposition of each Weld Rejected	✓			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	✓			
.266(c)	Location of each Crossing with another Pipeline	✓			
.266(d)	Location of each buried Utility Crossing	✓			
.266(e)	Location of Overhead Crossings *no overhead crossing*			✓	
.266(f)	Location of each Valve and Test Station	✓			
PRESSURE TESTING					
.310	Pipeline Test Record	✓			
.305(b)	Manufacturer Testing of Components	✓			
.308	Records of Pre-tested Pipe	✓			
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual (1 per yr/15 months)	✓			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	✓			
.402(c)(10)	Abandonment of Facilities *no facilities abandoned*			✓	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	✓			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	✓			
.402(d)(1)	Response to Abnormal Pipeline Operations	✓			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	✓			
.402(e)(1)	Notices which require immediate response	✓			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	✓			
.402(e)(9)	Post Accident Reviews	✓			
.403(a)	Emergency Response Personnel Training Program	✓			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (1 per yr/15 months)	✓			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	✓			
.404(a)(1)	Maps or Records of Pipeline System	✓			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	✓			
.404(a)(3)	MOP of each Pipeline	✓			
.404(a)(4)	Pipeline Specifications	✓			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	✓			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	✓			

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	✓			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	✓			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	✓			
.406(a)	Establishing the MOP	✓			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	✓			
.412(a)	Inspection of the ROW	✓			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	✓			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk ***no facilities***			✓	
.420(b)	Inspection of Mainline Valves	✓			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/7 ½ months** HVL)	✓			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE 5 yrs). ***No HVL tanks***			✓	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/7 ½ months** HVL)	✓			
.430	Inspection of Fire Fighting Equipment	✓			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	✓			
	PUBLIC AWARENESS PROGRAM				
.440(e & f)	Documentation properly and adequately reflects implementation of operator's Public Awareness Program requirements - Stakeholder Audience identification, message type and content, delivery method and frequency, supplemental enhancements, program evaluations, etc. (i.e. contact or mailing rosters, postage receipts, return receipts, audience contact documentation, etc. for emergency responder, public officials, school superintendents, program evaluations, etc.). See table below.	✓			

Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006.

API RP 1162 Baseline* Recommended Message Delivery Frequencies	
Stakeholder Audience (Hazardous Liquid Operators)	**Baseline Message Frequency (starting from elective date of Plan)**
Residents Along Right-of-Way and Places of Congregation	2 years
Emergency Officials	Annual
Public Officials	3 years
Excavator and Contractors	Annual
One-Call Centers	As required of One-Call Center

* Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.

		S	U	N/A	N/C
.440(g)	The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area.	✓			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	✓			
.442(c)(2)	Notification of Public/Excavators	✓			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	✓			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	✓			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	✓			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	✓			

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Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	PART 195 - PERFORMANCE AND RECORDS REVIEW	**S**	**U**	**N/A**	**N/C**
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)	✓			
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	✓			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) ***no unprotected pipeline***			✓	
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	✓			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	✓			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	✓			
.589(c)/.575	Electrical isolation inspection and testing	✓			
.589(c)/.577	Testing for Interference Currents	✓			
.589(c)/.579(a)	Corrosive effect investigation 6B is inhibited	✓			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (**2 per yr/7½ months**)		1		
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	✓			
.589(c)/.583(a)	Atmos. Corr. Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)	✓			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	✓			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	✓			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	✓			

Comments:

1 Internal coupons or other monitoring equipment have not been evaluated since October 2007.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	✓		
194.111	RSPA Tracking Number: **867 Chicago** Approval Date: **1/29/08**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	✓		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	✓		
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4]	✓		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	✓		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the Asequence number.@ It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Recent PHMSA Advisory Bulletins

Leave this list with the operator.

Number	Date	Subject
ADB-06-01	January 17, 2006	Pipeline Safety: Notice to Operators of Natural Gas and Hazardous Liquid Pipelines To Integrate Operator Qualification Regulations into Excavation Activities
ADB-06-02	June 16, 2006	Submission of Public Awareness Programs for Review
ADB-06-03	November 22, 2006	Pipeline Safety-Notice to Operators of Natural Gas and Hazardous Liquid Pipelines to Accurately Locate and Mark Underground Pipelines Before Construction-Related Excavation Activities Commence Near the Pipelines
ADB-06-04	December 28, 2006	Pipeline Safety: Lessons Learned From a Security Breach at a Liquefied Natural Gas Facility
ADB-07-01	April 27, 2007	Pipeline Safety: Senior Executive Signature and Certification of Integrity Management Program Performance Reports
ADB-07-02	September 6, 2007	Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-07-02	February 29, 2008	Correction - Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

For more PHMSA Advisory Bulletins, go to http://ops.dot.gov/regs/advise.htm

Office of Pipeline Safety

Field Data Sheet

Company: Enbridge Energy

Pipeline Inspected: Griffith Terminal, Lines 6A, 6B, 14, 64
Dates: October 8-10, 2008 and January 21, 2009

No	Location	On Read	Off Read (if applicable)	Cust. Side (if applicable)	Additional Comments
	October 8 6B MP 519.7 New Carlisle Station	-1.828			BV optd by CC ok
	MP 515.366	-1.086	c/s -0.576		Critical bond with South Shore 6.6 A to SS
	MP 512.85 350E	-2.461 -2.445		-2.440 f/s	Critical bond with Wolverine
	MP 507.664 Co Rd 400N	-1.272	c/s -0.746		
	MP 500.145 500 Forester Rd.	-0.913			
	MP 400 LaPorte Station	-3.012 -2.532			discharge suction
	MP 489.14	-1.663			BV optd ok with local MOV
	MP 483.155 Co Rd 700N	-1.353	-0.816 c/s		
	MP 483.181 ANR 30" flx			-1.426	
	MP 483.19 ANR 22" flx			-1.328	
	MP 480 Wheeler Station	-1.430			BV optd ok manually
	MP 475.191 ES Deep River	-1.290			BVoptd ok manually
	MP 472 Hwy 53 Tecumseh 20" flx	-1.130	-0.708		
	MP 466.883 12" Marathon flx			-1.620	
	MP 466.88 8" Marathon flx			-1.779	
	MP 466.72 ES Broad St	-1.327		-0.613	
	6A MP 464.85 Kennedy	-1.344	-0.610 c/s		
	64 MP 25.4386 Kennedy	-1.59			
	6A MP 455.72 ES State St.	-1.624	-0.493		
	64 ES State St	-1.572			
	64 MP 15.4053	-2.613			
	64 MP 14.2992 W Forest Preserve Rd BV	-1.542			1.4 VAC Partially optd locally ok
	October 9 6A MP 448.208 Central Ave	-1.871			5.6 A to rectifier
	6A MP 442.192 St. Francis Rd.	-1.314			4.83 VAC
	64 MP 7.3502 Shell flx 6A same location	-0.995 -1.104			9 VAC 2.5 VAC

Inspector:

Office of Pipeline Safety

Field Data Sheet

Company: Enbridge Energy

Pipeline Inspected: Griffith Terminal, Lines 6A, 6B, 14, 64
Dates: October 8-10, 2008 and January 21, 2009

No	Location	On Read	Off Read (if applicable)	Cust. Side (if applicable)	Additional Comments
	64 MP .2320A line 14/64 .2320 B Nicor 30" .2320C NGPL/KM .2320E Nicor 6" .2320F Chicap	-1.051 -1.309 -1.385 -1.212 -1.163			
	14/64 Pig Trap Area	-0.942			At 64 ML BV
	Mokena Station Reinjection out to 6A Incoming 6A	 -1.255 -1.197			
6A	MP 437.52 BV	-1.163			0.5 VAC manually optd partially close, remote optd open ok
	MP 432.429 Parker Rd	-1.908		-2.005	Aux Sable Liquids gas flx
	MP 426.783 Lockport Inlet to flow meter Enbridge to Shell Mustang Line change Mustang facilities Enbridge line in Shell	 -1.929 -2.426 -1.298 -2.22			5.0 A to Shell rectifier
	MP 425.945 BV	-1.589			Partially opted ok by CC
	MP 425.449 ES Canal Arch	-1.782			
	MP 420.971 ES Weber flx	-0.995	-0.71 c/s	-1.23	
	MP 414.385 119th St. NS OneOK crossing	-1.409	-0.635 c/s	-1.59	
	MP 412.215 Naperville Station Suction/discharge KM lines	 -2.68 -1.74			
	October 10 Griffith Terminal Tank 74 North South East West Tank 71 North South East West	 -3.261 -2.965 -3.502 -2.856 -4.123 -4.549 -3.597 -4.076			

Inspector:

Office of Pipeline Safety
Field Data Sheet

Company: Enbridge Energy **Pipeline Inspected:** Griffith Terminal, Lines 6A, 6B, 14, 64
Dates: October 8-10, 2008 and January 21, 2009

No	Location	On Read	Off Read (if applicable)	Cust. Side (if applicable)	Additional Comments
	Griffith Terminal				
	Tank 70				
	North	-1.875			
	South	-1.942			
	East	-2.00			
	West	-2.21			
	64 out of inlet pipe to transfer piping to Hartsdale	-2.119			
	6A inlet to manifold	-1.386			
	6B outlet to booster pump	-1.371			
	Hartsdale Terminal				
	Tank 1605 manifold	-2.013			
	Tank 1606 inlet piping	-3.79			
	North	-3.165			
	South	-3.201			
	East	-3.750			
	West	-3.489			
	Tank 1609				
	North	-3.035			
	South	-2.836			
	East	-3.228			
	West	-3.162			
	January 21				
6A	MP 385.96 NS I90	-0.86	-0.68 c/s		
	MP 392.384 BV	-1.305			Optd manually ok
	MP 403.888 Butterfield Rd	-0.962	-0.601		
	MP 407.132 Chicago B&O RR	-0.857	-0.715 c/s		0.12 VAC
14	MP 385.25 CC&P RR south	-2.00	-0.745 c/s		-0.86 VAC
	MP 391.2 Lees Rd	-1.812			0.2A ANR to Enbridge
	MP 400.591 BV	-1.006			0.66 VAC optd by CC ok
	MP 408.196 Jericho Rd	-1.175			0.83 VAC
	MP 417.92 BV	-1.318			0.71 VAC optd locally ok
	MP 421.979 Hwy 71 ANR	-1.135		-1.231	2.7 A to ANR
	MP 429.395 Church road	-1.655			1.5 VAC
	MP 435.914 Ridge Road	-0.94			
	MP 439.313 BV	-1.495			0.13 VAC manually optd ok
	MP 444.284 NGPL flx	-1.696		-1.72	-2.7 VAC
	MP 447.237 Hwy 53	-0.898			5.7 VAC
	MP 453.229 Cedar Road	-0.908			13.8 VAC

Inspector:

Office of Pipeline Safety
Field Data Sheet

Company: Enbridge Energy

Pipeline Inspected: Griffith Terminal, Lines 6A, 6B, 14, 64
Dates: October 8-10, 2008 and January 21, 2009

No	**Location**	**On Read**	**Off Read** (if applicable)	**Cust. Side** (if applicable)	**Additional Comments**
	MP 458.279 Metra RR	-1.086	-0.702 c/s		5.7 VAC
	MP 461.148 BV	-1.875			0.39 VAC

Inspector:

ENBRIDGE

PIPELINE INTEGRITY

HEAVY OIL PIPELINE SYSTEM INTERNAL CORROSION MONITORING COMPLIANCE REPORT (22-Oct-2009 Update)

Enbridge Pipelines Inc.
Enbridge Energy Partners Inc.
Pipeline Integrity
October 2009

Table of Contents

1. Executive Summary

This report has been prepared to address the regulated requirement for internal corrosion monitoring of the portion of Enbridge heavy oil transmission system in the states of Illinois and Indiana. This segment of pipeline is chemically treated to mitigate internal corrosion, and is designated "Line 6B".

Internal corrosion of heavy oil pipelines occurs sporadically in relation to where corrodents in the oil settle onto the pipe floor, as opposed to an inherent corrosivity of the bulk fluid - which is very low[1,2]. Enbridge employs a variety of methods to monitor internal corrosion, and to evaluate internal corrosion risk. No available internal corrosion monitoring technology has achieved widespread industry endorsement as the 'best of breed' for crude oil pipelines subject to underdeposit corrosion. As such, monitoring tools and techniques are in a state of flux as newer and better state-of-the-art technologies are developed.

In 2007, the previous generation of internal corrosion monitors on Line 6B went offline due to communication/instrument problems. These monitors were not immediately replaced because the 'next generation' monitoring technology required analysis of current in-line inspection data to produce high quality monitor results, which was not available, and Enbridge heavy oil system was already being adequately monitored.

The historically effective treatment program for this segment of heavy oil pipeline was maintained from before the monitors went offline to the present time. Monitoring of operating parameters through this period has shown consistency, both historically and with other segments of the heavy oil system.

Enbridge manages the internal corrosion threat of its heavy oil pipelines using data collected integrated over the entire system. These data show continuous monitoring of chemically treated portions of the heavy oil system, as well as periodic monitoring through direct UT examinations of Line 6B specifically and weight loss coupons exposed to Line 6B fluids. These monitoring efforts demonstrate compliance with the objectives indicated in CFR 195.579 for the 2008 calendar year.

Enbridge will continue to conduct direct examinations of Line 6B through 2009, and will install a high resolution wall loss corrosion monitor in Q1/Q2 2010 following receipt and acceptance of the 2009 ILI data.

[1] CanMet WRC 95-32 Relative Corrosivities of IPL Fluids
[2] ARC Report WP41144-00758 FR-1

2. Review of Monitoring Requirement (CFR 195.579)

195.579 What must I do to mitigate internal corrosion?

(a) General: If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

(b) Inhibitors: If you use corrosion inhibitors to mitigate internal corrosion, you must –

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect;

(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(3) Examine coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(4) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7-½ months.

The 2008 US regulatory audit of Indiana and Illinois identified a potential non-compliance issue affecting Line 6B. This line segment has had a chemical treatment program to mitigate internal corrosion since 1995. As part of the initial program, internal corrosion monitoring devices were installed. These monitors were manually interrogated at first, and later converted for remote monitoring. Recently (2007) these internal corrosion monitoring devices went offline. These monitors were not repaired or replaced at the time for the following reasons:

- Enbridge heavy oil pipeline system (which includes Line 6B) is continuously monitored without these devices.
- Hydrogen permeation monitors (the type that failed) are no longer Enbridge standard because of difficulty interpreting data and maintenance issues.
- The next-generation replacement equipment requires ILI data from recent, successive high resolution inspections, which will not be available until late 2009 or 2010.

Enbridge will evaluate the next ILI results to determine if additional discrete monitoring devices can provide useful information beyond what is already available – should this be the case, additional monitors will be installed on Line 6B. The remainder of this document is provided to demonstrate Enbridge conformance with each of the clauses in CFR 192.579, and provides additional information to assist with the audit process. Specific elements are discussed as follows:

Section 3: Demonstrates that Line 6B is a subcomponent of Enbridge Heavy Oil System and that Enbridge uses consistent and appropriate chemical treatment dosage (195.579-b-1);
Section 4: Addresses Enbridge IC monitoring programs (195.579-b-2 through 195.579-b-4);
Section 5: Summarizes Enbridge real time monitoring of corrosion related parameters;
Section 6: Summarizes the effectiveness of Enbridge chemical treatment programs as demonstrated through successive high resolution in-line inspection.
Section 7: Discusses the results and implications of direct examinations conducted through 2008 and 2009.

3. Enbridge Heavy Oil Transmission System

Enbridge operates one of the largest and most comprehensive crude transmission systems in North America. This system transports approximately 100 different commodities through more than 8,500 miles of pipe ranging in size from 12" to 48". This system was built or acquired over sixty years.

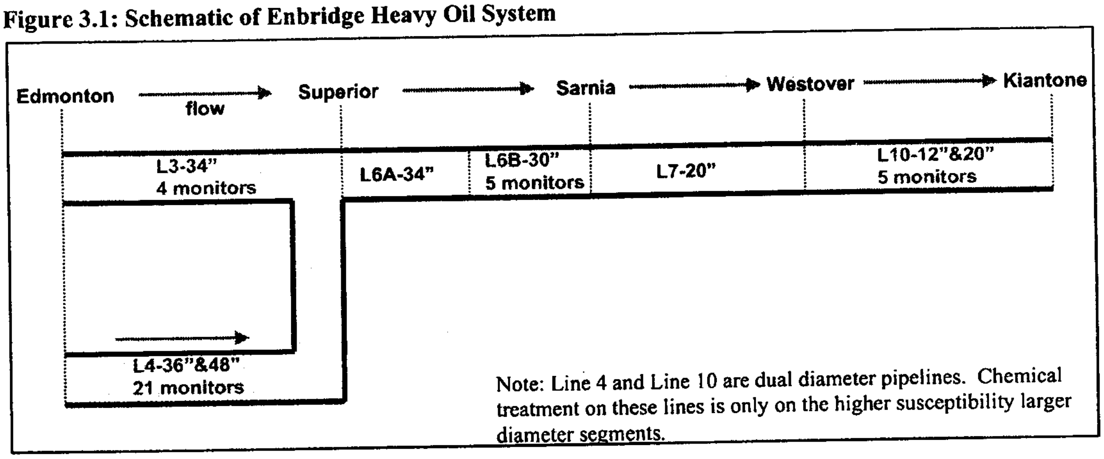
A legacy of the Enbridge system development resides in the use of 'common numbering' for different portions of the system. This nomenclature was originally used to identify pipelines that were used for different products, to differentiate segments with different physical characteristics (ie. diameter), or to distinguish expansion projects from existing pipelines. This naming system is further subdivided by geographic region, by pump station, by pig trap facilities, by milepost, by girthweld (pipe joint), and is ultimately maintained on an inch by inch basis using in-line inspection with subsequent excavation/repair programs.

In operation, such naming convention can lead to the false impression that different pipeline numbers represent different pipeline entities. From an internal corrosion management perspective, it is more appropriate to group pipelines carrying identical commodity streams. This report only discussed Enbridge heavy oil transmission system as illustrated in figure 3.1.

All segments of this system receive regular surveillance through scheduled in-line inspection and through monitoring of operating conditions. Some segments of this system have been shown to have a higher risk and incidence of internal corrosion due to flow conditions, and these receive scheduled cleaning and chemical treatments to reduce internal corrosion. In-line inspection provides the best validation of system integrity, and the strongest evidence of chemical treatment efficacy. Discrete internal corrosion monitors are deployed on the most susceptible segments at the most active internal corrosion sites – as determined by successive high resolution in-line inspection.

Figure 3.1 indicates the chemically treated segments of Enbridge heavy oil transmission system, as well as the number/location of discrete internal corrosion monitors.

Figure 3.1: Schematic of Enbridge Heavy Oil System



3.1. Consistency of Operation

Enbridge regularly assesses operating pipelines in order to identify pipelines at increased risk of internal corrosion. Flow regime and the presence of commodities associated with the historical incidence of internal corrosion are two key factors considered when evaluating internal corrosion potential. Table 3.2 provides a summary of pipeline operations for Enbridge heavy oil system based on analysis of real-time data.

Table 3.2: Summary of Pipeline Operations

Line	Shutdown	Product Distribution				Characteristic Flow Factors		
		heavy crude	med crude	light crude	other crude	Re#	Velocity (m/s)	Fr#
L3-34"	12%	81%	5%	10%	3%	6139	1.19	1.29
L4-36"	11%	88%	3%	9%	0%	11692	1.77	1.26
L4-48"	11%	88%	3%	9%	0%	8769	0.99	1.00
L6A-34"	1%	97%	1%	2%	0%	15172	1.98	1.69
L6B-30"	15%	81%	9%	9%	0%	4191	1.00	1.24
L7-20"	8%	47%	4%	47%	2%	4505	1.11	1.37
L10-12"	3%	59%	3%	38%	1%	3050	1.57	2.18
L10-20"	3%	59%	3%	38%	1%	1830	0.57	1.00

The parameters common to the chemically inhibited pipelines include: percentage of heavy oil greater than 50%, operating velocity less than 1.20m/s, and densimetric Froude number less than 1.3. Densimetric Froude number provides a simple calculation for predicting water accumulation in oil under turbulent flow[3] and is believed to have relevance in predicting transportation and accumulation of solid contaminants.

3.2. Consistency of Chemical Treatment

The chemical treatment protocol used on Enbridge heavy oil system has been standardized. The chemical choice (PL1554, by GE Betz) and dosage rate was determined in 1994, with only a slight modification to inhibitor blend made in 1996. Figure 3.3 illustrates the formula used to determine the quantity of inhibitor required per injection, based on the surface area of the pipe being treated. This form of calculation is common in the pipeline industry, and is based on chemical utilization proportional to the surface area of the pipe being treated. The bacteria kill studies conducted in the early 1990's indicated that the chemical treatment duration should be at least 2 hours.

Figure 3.3: Calculation of Inhibitor Dosage

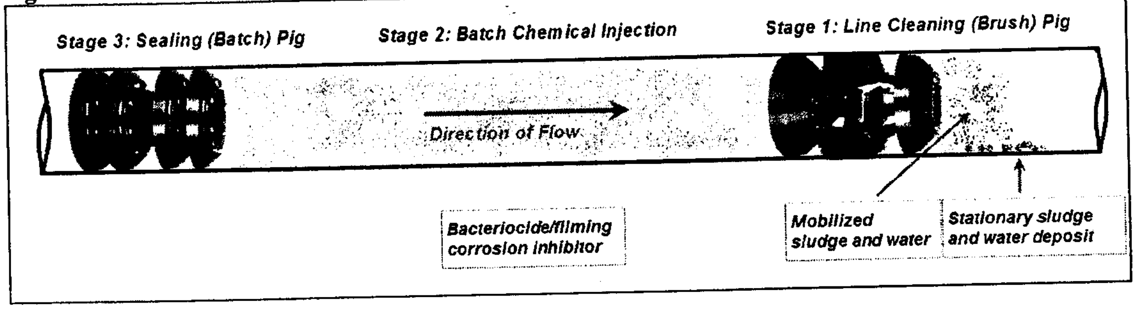
$$V = 2.03 * L * D$$

Where:
V = Volume of PL1554 required (in litres)
L = Length of treated section (in kilometers)
D = Diameter of pipeline (in inches)

The design of these batch treatments incorporates the use of brush equipped cleaning pigs in front of the chemical treatment to dislodge/transport corrodents, and to expose bacterial colonies to the biocidal filming inhibitor. Figure 3.4 illustrates a typical 'batch cleaning pig train' showing the chemically treated oil batch in relation to the front cleaning pig, and the back 'sealing' pig.

[3] NACE SP0208-2008, "Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines".

Figure 3.4: Line Cleaning/Batch Treatment Schematic



Enbridge has standardized this inhibitor treatment program to all sections of the heavy oil transmission system with similar operating characteristics and where ILI data indicates an elevated incidence of internal corrosion. All Enbridge pipelines presently using batch chemical treatments to prevent corrosion use the same chemical, and the same batch application protocol. Table 3.5 identifies the line segments with batch chemical treatment programs, by year of operation since 2001.

Table 3.5: Chemical Treatment Program Scope 2001-2008

	2001	2002	2003	2004	2005	2006	2007	2008
48" (L4)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
30" (L2)	Yes	Yes	Yes	Yes	Yes	Yes	No	No
34" (L3)	No	No	No	No	No	No	Yes	Yes
34" (L6B)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
20" (L10)	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes

NB: Operations of Line 2 and 3 switched in 2007, as a result – the chemical program formerly on Line 2 was cancelled, and chemical treatment of Line 3 was initiated. The Line 10 chemical program was started in 2002.

4. Internal Corrosion Monitoring using Discrete Monitors

Enbridge uses high resolution monitors on pipelines that have elevated IPC susceptibility and/or have mitigation programs in place. High resolution monitors provide more rapid feedback on the status of internal corrosion processes than in-line inspection can provide, but do not provide as comprehensive pipe coverage as in-line inspection. High resolution IPC monitors are either manually 'read' or configured with remote access to provide more frequent data. In addition to the high resolution IPC monitors, some Enbridge sites are equipped with weight loss coupons.

Section 4.1 and 4.2 describe the two most broadly deployed IPC monitoring technologies on the Enbridge system, while section 4.3 discusses the output of these results.

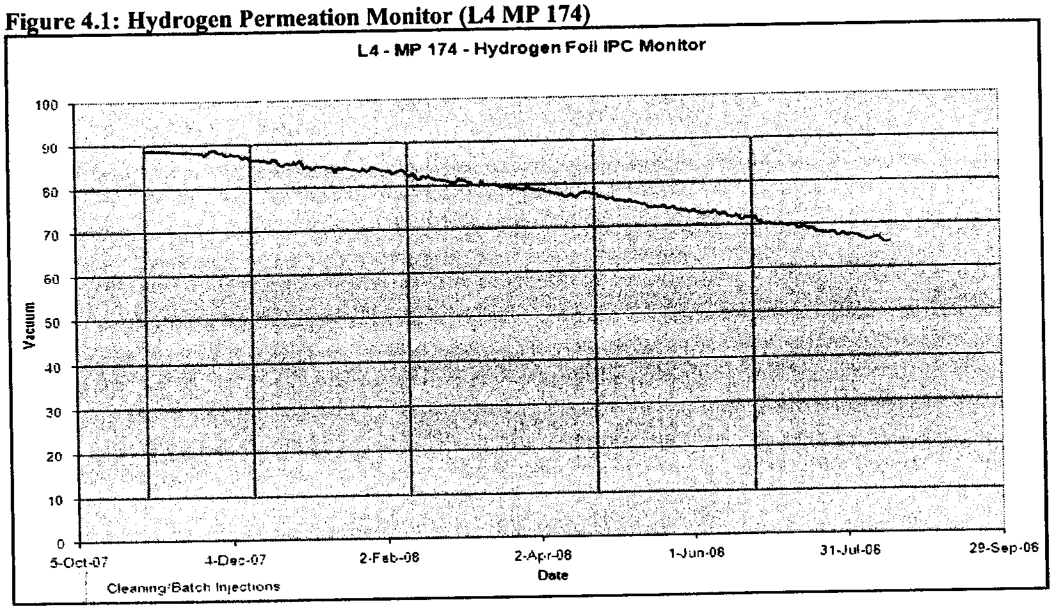
Section 4.4 discusses weight loss coupon results from the Stockbridge station on Line 6B.

4.1. Hydrogen Permeation Monitors (Betafoils)

Enbridge began using hydrogen permeation patch probes ('Betafoil') for internal corrosion monitoring devices in 1993. This monitor is based on the principle that corrosion processes create nacient hydrogen (H°). Most of this hydrogen combines with other hydrogen atoms to create hydrogen gas on the corroding metal surface, but some hydrogen migrates through the steel to form hydrogen gas on the outside surface of the pipe. The Betafoil uses the amount of hydrogen gas produced on the outside wall of the pipe as an indicator of internal corrosion activity.

The primary advantage of hydrogen foils is their rapid response to changing conditions. Hydrogen flux is generated immediately by chemical processes, and the migration of hydrogen through the pipe wall occurs over a small number of hours. The primary disadvantages of hydrogen foils are the lack of correlation between hydrogen diffusion rate and corrosion rate[4] and operational reliability issues. Figure 4.1 illustrates the output from a hydrogen permeation type monitor providing valid data.

Figure 4.1: Hydrogen Permeation Monitor (L4 MP 174)



[4] NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications"

Enbridge stopped installing hydrogen foil devices in 2005 in favor of other technologies more suited to monitoring pitting corrosion, and only maintains hydrogen foils that demonstrate reliable data. Enbridge maintains historical hydrogen foil records, trended against time.

4.2. Electrical Resistance Tomography (FSM-IT)

Enbridge installed its first electrical resistance tomograph in 2002. This monitor can detect metal loss through changes to the electrical characteristics of a pipe wall. The 'resistance tomograph' is created by passing an electric current through the pipe wall and measuring the voltage drop between electrodes connected to the pipe surface. The resistance (or voltage drop) between pins can be correlated to metal loss, which is converted to pit depth using appropriate sizing models. Since 2005, the FSM-IT electrical resistance matrix technology has been the instrument of choice for new Enbridge corrosion monitors.

The primary advantage of Electrical Resistance Tomography monitors is that a measure of remaining wall thickness can be directly calculated from the data, and corrosion growth observed. Other benefits include: only metal loss causes instrument response, service requirements are low, pitting is observable and can be differentiated from general corrosion, instruments are temperature compensated, and trend continuity is retained through monitor outages or long intervals between readings.

Figure 4.2 represents FSM-IT monitor output in 'tomograph view', showing accumulated wall loss in a planar 'C-Scan' pipe view. Figure 4.3 presents the accumulated wall loss of the deepest corrosion pits trended against time.

Figure 4.2: FSM-IT Tomograph

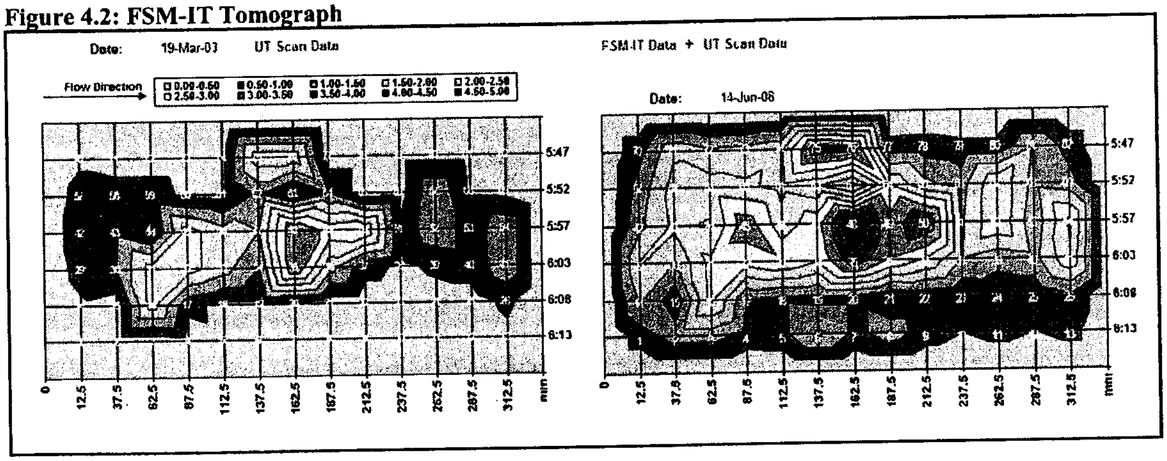
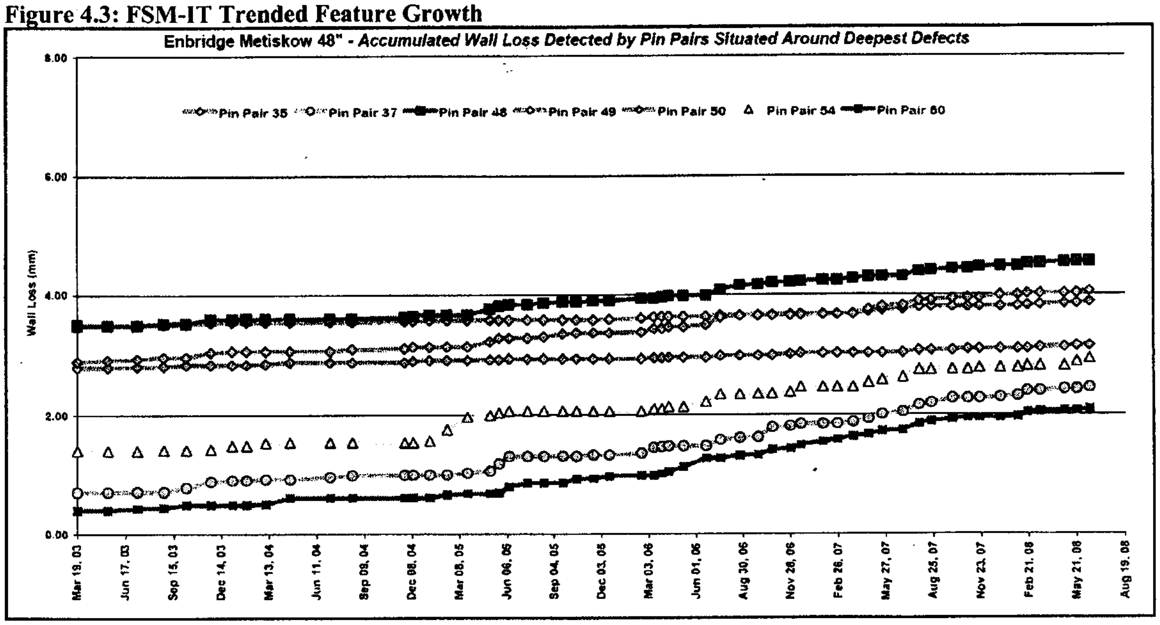


Figure 4.3: FSM-IT Trended Feature Growth



Enbridge maintains a record of the deepest internal corrosion pit in the monitor matrix, trended against time.

4.3. Monitoring Data Analysis

The effectiveness of Enbridge chemical treatment program is assessed by considering the monitoring data of all internal corrosion monitors. Individual monitor results must be evaluated against historical trends and assessed for sources of error such as may result from too-frequent interrogation, or equipment malfunction.

Although monitor results from one system cannot be compared with those of unrelated systems, corrosion experience in similar systems often correlate[5]. Based on the equivalence of products throughout the heavy oil system, the similarity in operating parameters, the consistent chemical treatment protocol used, and the monitoring data from other parts of Enbridge heavy oil system; it is concluded that continuous monitoring of Line 6B has been maintained and that the effectiveness of the chemical treatment program is demonstrated.

Table 4.4 provides a summary of this analysis.

[5] NACE RP0775-2005 "Preparation, Installation, Analysis and Interpretation of Corrosion Coupons in Oilfield Operations"

Table 4.4: Monitor Data Summary - Heavy Oil System

		Monitor	Service History		Interrogation Method		Outage History		Corrosion Trends Identified (long term max. pitting rate)
Line	MP	Type	Start	End		Ave. Interval	# Events	Cum. Time	
3	139	ERM	Oct-07	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
3	205	ERM	Oct-07	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
3	837	ERM	Sep-07	Operating	Manual	3 mo.	0	None	CGR: <1mpy average
3	950	ERM	Sep-07	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
4	134	H Probe	<Jan-04	Operating	RMU	Daily	1	6 mo.	None - stable when operating
4	140	H Probe	<Jan-04	Operating	RMU	Daily	1	18 mo.	None - stable when operating
4	172	H Probe	<Jan-04	Operating	RMU	Daily	2	20 mo.	None - stable when operating
4	209	ERM	Oct-07	Operating	Manual	3 mo.	0	None	CGR: <1mpy average
4	246	H Probe	<Jan-04	Operating	RMU	Daily	1	15 mo.	None - stable when operating
4	246	ERM	Oct-07	Operating	Manual	3 mo.	0	None	CGR: <1mpy average
4	287	ERM	Nov-07	Operating	Manual	3 mo.	0	None	CGR: <1mpy average
4	255	ERM	Aug-06	Operating	Manual	3 mo.	0	None	CGR: <5mpy average
4	326	ERM	Aug-06	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
4	332	ERM	Aug-06	Operating	Manual	3 mo.	0	None	CGR: <5mpy average
4	364	ERM	Aug-06	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
4	402	ERM	Aug-06	Operating	Manual	3 mo.	0	None	CGR: <3mpy average
4	403	ERM	Aug-06	Operating	Manual	3 mo.	1	12 mo.	CGR: <1mpy average
4	471	H Probe	<Jan-04	Oct-08	RMU	Daily	2	21 mo.	None - stable when operating
4	842	ERM	Sep-07	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
4	843	H Probe	<Jan-04	May-08	RMU	Daily	2	15 mo.	None - stable when operating
4	947	H Probe	<Jan-04	Jun-08	RMU	Daily	1	6 mo.	None - stable when operating
4	976	H Probe	<Jan-04	May-08	RMU	Daily	1	7 mo.	None - stable when operating
4	989	H Probe	<Jan-04	Dec-07	RMU	Daily	1	7 mo.	None - stable when operating
4	989	ERM	Sep-07	Operating	Manual	3 mo.	0	None	CGR: <2mpy average
4	1026	H Probe	<Jan-04	May-08	RMU	Daily	1	7 mo.	None - stable when operating
6B	XXX	H Probe	Jan-05	Jan-06	RMU	Daily	1	36 mo.	None - stable when operating
6B	465	H Probe	May-96	May-06	Manual	Bi-Monthly	0	None	None - stable when operating
6B	465	H Probe	May-06	Oct-07	RMU	Daily	1	14 mo.	None - stable when operating
6B	494	H Probe	Apr-96	May-06	Manual	Bi-Monthly	0	None	None - stable when operating
6B	494	H Probe	May-06	Oct-07	RMU	Daily	1	14 mo.	None - stable when operating
10	1883	H Probe	<Jan-04	Operating	RMU	Daily	1	7 mo.	None - stable when operating
10	1885	H Probe	<Jan-04	Operating	RMU	Daily	1	6 mo.	None - stable when operating
10	1899	H Probe	<Jan-04	Operating	RMU	Daily	1	7 mo.	None - stable when operating
10	1911	H Probe	<Jan-04	Operating	RMU	Daily	2	18 mo.	None - stable when operating
10	GI	H Probe	Aug-04	Dec-08	RMU	Daily	2	20 mo.	None - stable when operating

NB: Green highlighted cells reflect monitors that are currently reporting.

NACE RP0775 provides a guide for interpreting corrosion rates in oil production systems, as shown in Table 4.5. Based on RP0775 guidelines and these monitoring data, the maximum pitting rate observed at all ERM locations indicated 'low' corrosion growth rates. No corrosion trends were identified from the hydrogen foils.

Table 4.5: Qualitative Categorization of Carbon Steel Corrosion Rates (RP0775-2005)

Category	General Corrosion Rate (mpy)	Maximum Pitting Rate (mpy)
Low	<1.0	<5.0
Moderate	1.0-4.9	5.0-7.9
High	5.0-10	8-15
Severe	>10	>15

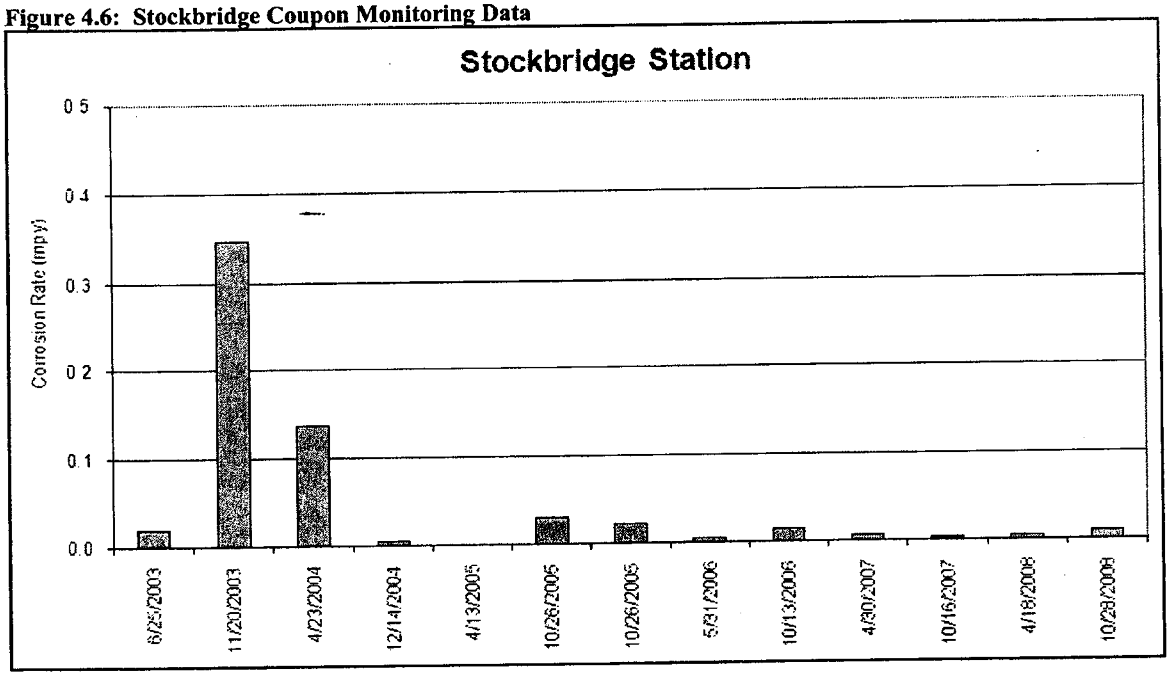
4.4. Stockbridge Weight Loss Coupon

Weight loss coupons are an established method of evaluating internally corrosive conditions in both mitigated (inhibited) and unmitigated pipeline systems. Coupons are typically made of pipe steel (or mild steel similar to the pipe steel) and are placed in the internal pipeline environment for an exposure period of several months. Upon retrieval from the system, coupons are cleaned and gravimetrically assessed for metal loss, which is converted to a corrosion penetration rate in accordance with the coupons dimensions.

The Stockbridge pump station coupon is located within the facility piping on a delivery line destined for Toledo (Line 17). All fluids contacting the Stockbridge coupon originate from Line 6B and are representative of the fluid corrosivity in Line 6B.

Inhibitor effectiveness may be assessed using coupons by comparing mitigated corrosion weight loss to unmitigated corrosion weight loss, or simply by ensuring that the weight loss of the mitigated system is at or below an acceptable threshold. Figure 4.6 provides the Stockbridge coupon monitoring results from June 2003 to October 2008. All of these data indicate general corrosion rates less than 0.4mpy, which is considered 'Low' according to NACE RP0775.

Figure 4.6: Stockbridge Coupon Monitoring Data



Review of inhibition records indicate that the relatively higher corrosion weight loss from November 2003 might have been caused by poor alignment of coupon deployment and batch inhibitor application: the coupon was deployed on June 13, 2003, whereas the inhibition was completed in May. As such, the majority of the coupons exposure time represented unmitigated conditions.

It should be noted that the two 'peaks' from November 2003 and April 2004 indicate such low level metal loss that these relative 'excursions' could have been the result of aggressive coupon cleaning rather than actual corrosion.

5. Monitoring of Operating Conditions Conducive to Internal Corrosion

PHMSA Advisory Bulletin ADB-08-08 advises operators to critically analyze operating conditions and internal corrosion risk factors. This ADB lists design factors, such as pipe configuration and topography, as well as factors that would affect the corrosivity of the fluid being transported or the likelihood of locally corrosive conditions developing.

These latter factors fall into the category of 'Indirect Measurement Techniques' as described in NACE Technical Committee Report 3T199[6]. 'Indirect Measurement' describes the measurement of any parameter that may influence, or is influenced by, metal loss or corrosion. Table 5.1 lists the factors listed in ADB-08-08 and NACE 3T199, along with Enbridge monitoring activities or considerations to address these parameters:

Table 5.1: Operating Conditions Conducive to Internal Corrosion

ADB-08-08	NACE 3T199	Enbridge Consideration of Factor
Commodity Type	Included	Enbridge assigns risk based on historical experience with different commodity types, and uses fluid properties for flow modeling
Flow rate	Included	SCADA(see note 1) input to IPC susceptibility model
Velocity	Included	SCADA input to IPC susceptibility model
Pressure	Included	SCADA data available, not included in susceptibility model
Topography	Not included	Included for monitor site selection – used to determine principal corrosion mechanisms as feedback to mitigation method selection
Foreign materials	Included in other factors	Batch specific S&W is determined, off spec batches identified. Enbridge assumes all crudes contain corrosive materials
Water chemistry	Included	All commodity streams are assumed to contain corrosive water
Bacteria	Included	All commodity streams are assumed bacterially active
Temperature	Included	SCADA input to IPC susceptibility model
Operations: Normal	Included in other factors	SCADA input to IPC susceptibility model
Operations: Upset	Included in other factors	SCADA input to IPC susceptibility model
Upstream Upsets	Included in other factors	Batch specific S&W is determined

Note 1: "Supervisory Control and Data Acquisition" – Enbridge's real time pipeline control and monitoring systems.

Enbridge has used annualized commodity flow data as a key input to determining commodity and flow related internal corrosion susceptibility factors from 2005-2009, and is presently upgrading the interface between the IPC Susceptibility Model and Enbridge SCADA system. This upgrade will allow operational upset to be more accurately tracked and managed.

5.1. PI Data (SCADA) Analysis for 2008

Enbridge PI Data system provides access to pipeline monitoring data collected and archived by Enbridge control centre. Key data include flowrate, temperature, product density, and pressure at input and output locations. The PI Data system allows direct input of operating data into MS Excel to facilitate further flow analysis and generation of operating statistics. The data in table 3.2 was generated using this application.

[6] NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications"

In addition to tabular data, this system allows visual representation of the operating data. Examples of these outputs are shown for Line 6B in figures 5.1, through 5.4. This system is presently being upgraded to automate the generation of monthly operating spectra for comparison to the previous years operation, thus allowing more rapid detection and response to changes in system operations (Management of Change).

Figure 5.1: Hourly Operating Data – Flowrate

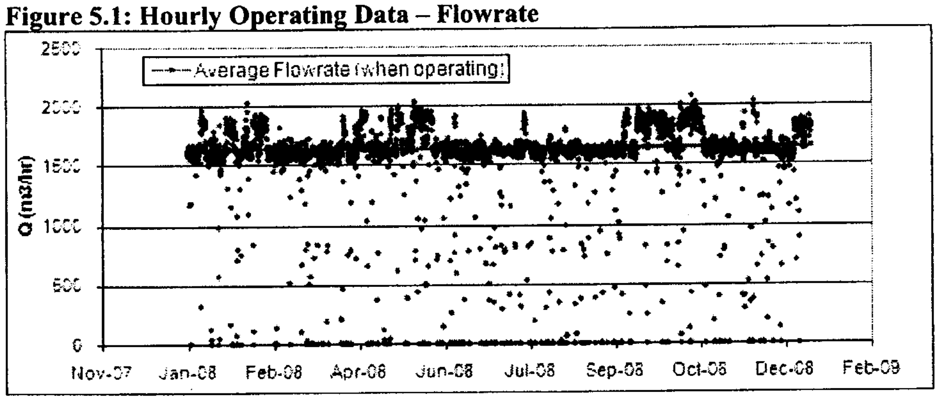


Figure 5.2: Hourly Operating Data – Densimetric Froude Number

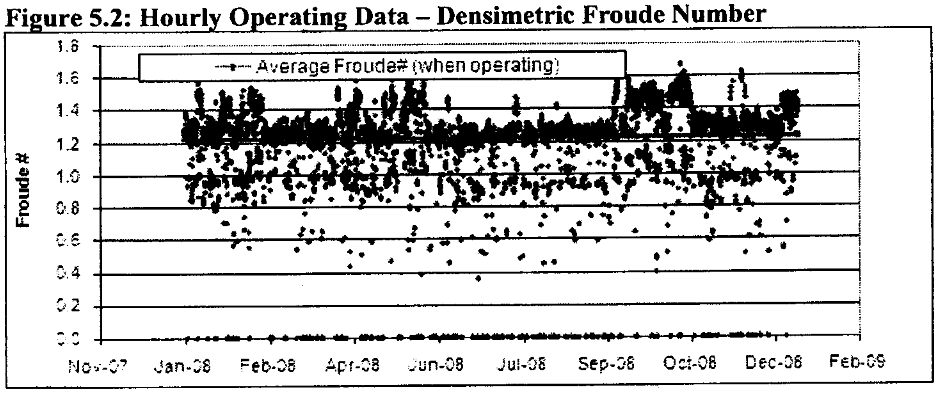


Figure 5.3: Hourly Velocity Histogram

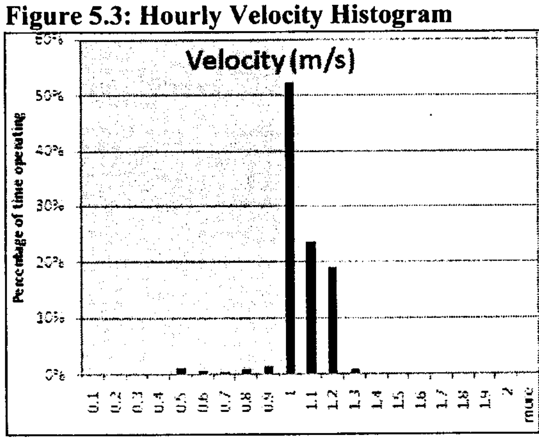
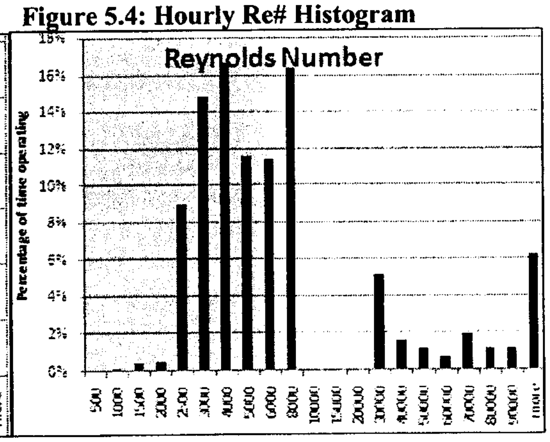


Figure 5.4: Hourly Re# Histogram



6. Effectiveness of Inhibition Program

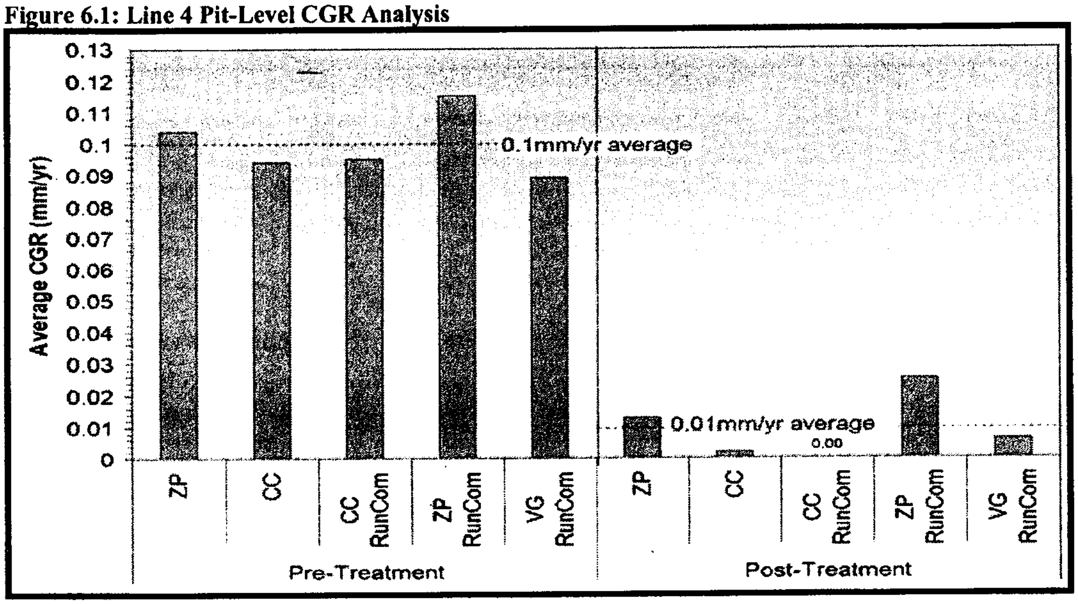
The heavy oil pipe segment most affected by internal corrosion is Line 4-48". Hence, the majority of discrete monitors are installed in this section, and the majority of technical analysis is performed on this section. The following analyses were performed to evaluate the benefit of the present chemical treatment program. These, or better results may be expected on the heavy oil segments less affected by internal corrosion.

6.1. RunCom Analysis

The GE RunCom™ analysis matches individual corrosion pits signal indications from successive in-line inspections using a common feature sizing algorithm to process both datasets to reduce error. Additional QA processes are used to normalize data and remove analyst error. The reported accuracy and confidence in corrosion growth rates using the RunCom™ method is higher than can be achieved through in-house ILI comparisons.

Figure 6.1 presents the results of pit level corrosion growth rate analysis from several pipe segments. Analyses performed by GE (RunCom™) as well as Enbridge in-house analyses are provided. These data indicate that the average pitting corrosion rate reduction that can be attributed to Enbridge chemical mitigation programs is approximately 90%.

Figure 6.1: Line 4 Pit-Level CGR Analysis



6.2. Reduction in Level 1 CGR – Modified Method

The most recent inline-inspections from the Kerrobert to Herschel Line 4 segment, which is the Line 4 segment with the greatest internal corrosion damage, were examined in detail. Tool offset error from Enbridge ILI QA process was considered for depth CGR analysis. Table 6.2 presents these data:

Table 6.2: Level 1 CGR for Kerrobert to Herschel Segment

	1999 ILI	2004 ILI	2008 ILI
Historic CGR (mm/yr)	0.103	0.091	0.079
Recent CGR (mm/yr)	N/A	0.035 (1999-2004)	0.010 (1999-2008)
Change %		-66%	-90%

Enbridge chemical treatment programs used on portions of Enbridge heavy oil system have been consistently applied since the late 1990's. These programs have been demonstrated to provide a 90% reduction in corrosion progression even on the segments most severely affected by internal corrosion. Higher mitigation efficacy rates can be expected on portions of the heavy oil system that are less affected by internal corrosion, including that portion designated Line 6B.

6.3. Line 6B In-Line Inspection and Excavation History

Line 6B has received a total of seven (7) in-line inspections since 1979. This line demonstrates very little progression of internal corrosion, as illustrated by the small number of internal corrosion features meeting Enbridge excavation criteria. This history is summarized as follows:

YEAR	**Tool**	**Results**
1979	Low Res MFL	Few internal corrosion indications
1988	Low Res MFL	Few internal corrosion indications
1993	Low Res MFL	Several internal corrosion features
1994	High Res MFL	Several internal corrosion features, some meeting excavation criteria. 25-30 excavations validate the existence of internal corrosion, but only one (1) would have met current depth criteria for excavation (>50%). Chemical treatment program is initiated.
1999	High res UT	No features meet excavation criteria
2004	High res UT	One (1) feature excavation criteria
2007	High res MFL	Supplementary ILI performed to augment 2004 USWM data. Five (5) excavations issued as result of regarded data
2009	High res UT	Presently being implemented (September/October)

The favorable monitoring results presented in section 4 are corroborated by the decrease in Level 1 CGR (section 6.2) and the small number of internal corrosion features meeting excavation criteria from the in-line inspections conducted since 1999.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: **Enbridge Energy, Limited Partnership**	
OP ID No. [1] **11169**	**Unit ID No.** [1] **3083**
H.Q. Address:	**System/Unit Name & Address:** [1]
Enbridge Energy, Limited Partnership 1100 Louisiana, Suite 3300 Houston TX 77002	PO Box 665 1103 Roosevelt Rd. Bemidji, MN 56601
Co. Official: Terrence McGill	**Activity Record ID#:** 119028
Phone No.: 713-821-2003	**Phone No.:**
Fax No.:	**Fax No.:**
Emergency Phone No.: 713-410-4767	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Patsy Bolk	Compliance Analyst I	715-394-1504
Jay Johnson	Senior Compliance Coordinator	715-394-1512
Randy Wilberg	Safety, Training and Compliance Coordinator	715-394-1412
Mike Goman	Supervisor, Regional Engineering and Services	715-394-1523
Mark Willoughby	General Manager, Superior Region	715-394-1534

PHMSA Representative(s) [1] Brian Pierzina – MN-OPS; Boyd Haugrose – MN-OPS

Inspection Date(s) [1] **:** 8/6-10/2007; 9/24-28/2007

Company System Maps (copies for Region Files):

Unit Description:

The unit consists of gun barrel 18, 20, 26, and 34 inch lines, and then a combination 36/48 inch (Line 4) from the ND/MN border to Clearbrook. From Clearbrook to Superior they have all the same, except they don't have the 20 inch. The 18 inch from Clearbrook to Superior is NGL.

Portion of Unit Inspected [1]

The entire unit was inspected.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/02/02 and 03/02/07.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	CONVERSION TO SERVICE	S	U	N/A	N/C
* .5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				X
	.52	Telephonically reporting accidents to NRC **(800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
Team O&M conducted in May of 2006.

		SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
Team O&M conducted in May of 2006.

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				X
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				X
		Welding procedures must be qualified by destructive testing.				X
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2004 Ed. Including addenda through July 1, 2005), except that a welder qualified under an earlier edition than listed in **' 195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 195-81 corr. Pub. 9/09/04; Amt 195-86 pub 06/09/06 eff 07/10/06.				X
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				X
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				X
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				X
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **' 195.228(b)** and per the requirements of **' 195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				X
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				X
		2. By qualified personnel				X
		3. By a process that will indicate any defects that may affect the integrity of the weld				X
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				X
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				

Comments:
Team O&M conducted in May of 2006.

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.302(a)	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions).				X
	.302(b)	Except for lines converted under **' 195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				X
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in ' 195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				X
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				X
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with '195.302.				X
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph (a) of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be followed to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				X
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				X
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph (c)(4) and minimizing the possibility of recurrence of accidents analyzed under paragraph (c)(5)?				X
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by ' 195.406, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				X
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by ' 195.406?				X
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under ' 195.402(c)(4) or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				X
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				X
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59.				X
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases?				X
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				X
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				X
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				X

Comments:
Team O&M conducted in May of 2006.

		ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				X
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				X
		iii. Loss of communications?				X
		iv. The operation of any safety device?				X
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:
Team O&M conducted in May of 2006.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:
Team O&M conducted in May of 2006.

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X

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EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				X
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				X
	.403(b)(2)	Make appropriate changes to the emergency response training program				X
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				X

Comments:
Team O&M conducted in May of 2006.

MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				X
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				X
		ii. Pump stations				X
		iii. Scraper and sphere facilities				X
		iv. Pipeline valves				X
		v. Facilities to which ' **195.402(c)(9)** applies				X
		vi. Rights-of-way				X
		vii. Safety devices to which ' **195.428** applies				X
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				X
	.404(a)(3)	The maximum operating pressure of each pipeline.				X
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				X
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				X
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under ' **195.402** apply.				X
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe.**				X
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year.**				X
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				X

Comments:
Team O&M conducted in May of 2006.

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MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	.406(a)(1)	The internal design pressure of the pipe determined by ' **195.106**. Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				X
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
Team O&M conducted in May of 2006.

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by ' **195.402(c)(9)**.				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
Team O&M conducted in May of 2006.

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
Team O&M conducted in May of 2006.

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INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				X
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years.**				X

Comments:
Team O&M conducted in May of 2006.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				X
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long,** except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				X

Comments:
Team O&M conducted in May of 2006.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				X
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **72 months,** but at least **twice** each calendar year.				X
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				X

Comments:
. Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
Team O&M conducted in May of 2006.

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP.**				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
Team O&M conducted in May of 2006.

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:
Team O&M conducted in May of 2006.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				

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		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				X
		2. **HVL** pipelines at intervals not to exceed **72 months**, but at least **twice** each calendar year.				X
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years.**				X
*	**.428(c)**	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Amt 195-86 pub 06/09/06 eff 07/10/06. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				X
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				X

Comments:
Team O&M conducted in May of 2006.

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	**.430**	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				X
		The equipment must be:				
		a. In proper operating condition at all times.				X
		b. Plainly marked so that its identity as firefighting equipment is clear.				X
		c. Located so that it is easily accessible during a fire.				X

Comments:
Team O&M conducted in May of 2006.

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	**.432(a)**	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				X
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **' 195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				X
*	**.432(c)**	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X

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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
Team O&M conducted in May of 2006.

		SIGN PROCEDURES	S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
*		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
Team O&M conducted in May of 2006.

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:
Team O&M conducted in May of 2006.

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				X

Comments:

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Comments:
Team O&M conducted in May of 2006.

DAMAGE PREVENTION PROGRAM PROCEDURES			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				X
	.442(b)	Does the operator participate in a qualified One-Call program?				X
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				X
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				X
		ii. How to learn the location of underground pipelines before excavation activities are begun.				X
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				X
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				X
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				X
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				X
		ii. In the case of blasting, any inspection must include leakage surveys.				X

Comments:
Team O&M conducted in May of 2006.

CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
.402(a) *	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X
*	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2002** (incorporated by reference). Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months).**				X
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months).**				X
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-2002.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				X
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				X
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 22 mos.**				X
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				X
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				X
	.575	Are there adequate provisions for electrical isolations?				X
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				X
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				X
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				X
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 2 months.**				X
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				X
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				X
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				X
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				X
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				X
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				X
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**				X
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory				X
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers		X		
.412	ROW/Crossing Under Navigable Waters	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings – Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks			X	
.434	Signs - Pumping Stations - Breakout Tanks	X			
.436	Security - Pumping Stations - Breakout Tanks	X			
.438	No Smoking Signs	X			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.575	Electrical Isolation; shorted casings	X			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)		X		

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)		X		

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.52	Telephonic Reports to NRC (800-424-8802)	X			
.54(a)	Written Accident Reports (DOT Form 7000-1)	X			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	X			
.56	Safety Related Conditions	X			
.57	Offshore Pipeline Condition Reports			X	
.59	Abandoned Underwater Facility Reports			X	
CONSTRUCTION					
.204	Construction Inspector Training/Qualification			X	
.214(b)	Test Results to Qualify Welding Procedures			X	
.222	Welder Qualification			X	
.234(b)	Nondestructive Technician Qualification			X	
.589	Cathodic Protection			X	
.266	Construction Records			X	
.266(a)	Total Number of Girth Welds			X	
	Number of Welds Inspected by NDT			X	
	Number of Welds Rejected			X	
	Disposition of each Weld Rejected			X	
.266(b)	Amount, Location, Cover of each Size of Pipe Installed			X	
.266(c)	Location of each Crossing with another Pipeline			X	
.266(d)	Location of each buried Utility Crossing			X	
.266(e)	Location of Overhead Crossings			X	
.266(f)	Location of each Valve and Test Station			X	
PRESSURE TESTING					
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			
.308	Records of Pre-tested Pipe	X			
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities	X			
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)				
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			X	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	X			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			
.440	Public Education/Awareness Program	X			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)		X		
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)			X	

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	X			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment **(2 per yr/7½ months)**	X			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**		X		
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:
195.49 Annual Reports – The 2005 Annual Report indicates 190 miles of HVL pipeline total. Speculation is that this would be the 18 inch from Clearbrook to Superior. There is nothing reported for HVL pipeline upstream of Clearbrook, even though the 20 inch is predominantly NGL from the Canadian Border to Clearbrook. Question as to the procedures for completing the Annual Report, and how the person compiling the information determines whether a pipeline that transports both crude and HVL is distinguished as either HVL or crude. Patsy will obtain volumes for 2005 and 2006 for the 20 inch and 18 inch. The 190 miles of HVL reported is for the 18 inch downstream of Clearbrook. In Patsy's follow-up letter, they indicated that the Reports would be revised to reflect that the 20" line 1 mileage, since it predominantly transports HVL's, instead of crude.

AOC's – Reviewed AOC database w/Jim Johnston via telephone. One key finding is that the AOC database indicates the date an AOC was entered in the database, rather than the date it occurred, which is the more relevant of the two dates. It doesn't appear that provisions have been established to allow for trending or evaluation based on occurred date and time.

195.402(e7) – Notification of Fire, Police, and other Public Officials. Question as to whether local emergency officials should be given a heads up in the event of a release. Possible concerns related to notification of fire and police when it may take some time to determine the extent, location, or circumstances associated with a release. Also, include provisions for courtesy calls when assistance is not required, but to give the officials a heads up.

Corrosion Records:
Discussed location at MP 1035.483 where 18 and 26 inch lines are indicated as winter reads, but don't appear to have been read, based on available information. Also discussed 1043.064C which indicates No Test Station (May be installed 2005) both in the 2005 survey data, and the 2006 survey data. Also discussed 1081.077 which has No Test Station for any of the 4 lines (Closest U/S? & D/S are one mile)

MP 1035.483 has 2004 reads for the 18 and 26 inch. 1043.064C has a test station within .1 miles, so no TS will likely be installed.

Discussed interference testing, and the need for more proactive testing among operators in Northern Minnesota.

Atmospheric corrosion inspections – exposed mainline does not have evidence of atmospheric corrosion inspections – Necktie River, MP 913, irrigation ditches MP 797, 829 (Tamarac River)

Field Inspection Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

195.308 – Pre-Tested Pipe – At Bemidji PLM facility – not visited as part of the field inspection.

195.410 ROW Markers – In general, the ROW is marked very well. However, where we walked into the Necktie River Crossing, there were no markers beyond the point we parked for a considerable distance downstream, including the river crossing. We walked in approximately ½ mile, with no markers, and none could be seen downstream of the river crossing for as far as we could see, which was another approximate half mile. Enbridge personnel noted this, and will be installing additional line markers.

195.432 – Breakout Tanks – None within BEP's inspection units.

195.583 – Atmospheric Corrosion – Exposed Necktie River crossing has no coating over much of its length. Enbridge has not established a method for conducting atmospheric corrosion inspections for exposed pipe in these types of circumstances. They will be addressing the overall problem, and have plans to re-coat the Necktie River crossing (18 inch Line 1) this winter.

Oil Pollution Act (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	X		
194.111	RSPA Tracking Number: **866,867,1666,665,70 1702** Approval Date: **February 95**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	X		
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	X		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*
Enbridge has just sent in revisions dated 7/18/2007.

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the Asequence number.@ It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

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:		**Inspector/Submit Date:** Brian Pierzina 9/5/07
		Peer Reviewer/Date:
		Director Approval 11/13/07

POST INSPECTION MEMORANDUM (PIM)		
Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:** 11169
Name of Unit(s):	Former Lakehead System – All of Minnesota	**Unit #(s):** 3083
Records Location:	119 North 25th Street East, Superior, Wisconsin	
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil and NGL	
Inspection Type:	Field & Records Inspection 420	**Inspection Date(s):** 8/6-10/2007
For OPS :	Hans Shieh	**AFO Days:** (5)
For MNOPS :	Brian Pierzina (8/7-10/07), Boyd Haugrose (8/6-10/07)	**AFO Days:** (9)
MNOPS CASE #: 007172		

Synopsis:

The 2007 Enbridge Standard Inspection was conducted by Brian Pierzina and Boyd Haugrose, from MNOPS, and Hans Shieh from Central Region. Participating from Enbridge were primarily Patsy Bolk, Jay Johnson, Mike Goman, Randy Wilburg and Mark Willoughby. Other Enbridge representatives participated within their areas of expertise.

The records portion of the inspection began Tuesday, August 7, 2007 at the Superior Office, and concluded Friday, August 10, 2007. The field portion of the inspection is scheduled to begin Monday, September 24, 2007, starting with the North Dakota portion of the system. The complete inspection report will be submitted following completion of the field portion of the audit.

The following items were covered in the recap session with Enbridge representatives on Friday, August 10th:

Thanks for your preparation and coordination during the audit. The following are comments related to unsatisfactory or pending issues, and areas we discussed where potential improvements may enhance your existing programs.

195.49 Annual Reports - The 2005 Annual Report indicates 190 miles of HVL pipeline total. Speculation is that this would be the 18 inch from Clearbrook to Superior. There is nothing reported for HVL pipeline upstream of Clearbrook, even though the 20 inch is predominantly NGL from the Canadian Border to Clearbrook. Question as to the procedures for completing the Annual Report, and how the person compiling the information determines whether a pipeline that transports both crude and HVL is distinguished as either HVL or crude. Patsy will obtain volumes for 2005 and 2006 for the 20 inch and 18 inch. The 190 miles of HVL reported is for the 18 inch downstream of Clearbrook. **Pending**

195.56 Safety Related Condition Reporting - Discovery is not well defined as it pertains to receipt of ILI anomalies from a tool vendor. There is a belief that the initial report should trigger the discovery clock, but other opinions have also been offered. The operator's procedures do not address this. **Possible NOA item** - although it would not likely be issued if procedures addressed discovery prior to preparation of the inspection report.

195.403(b) - Records indicated some individuals exceeded the 15 month requirement for tabletop exercises, although it appears there may have been two sessions attended during 2006 with the latter overwriting the former, consequently appearing that some individuals have exceeded the 15 month requirements. Recordkeeping function may need to be modified so that compliance with the interval requirement can be more easily demonstrated. **Comment**

AOC's - Reviewed AOC database w/Jim Johnston via telephone. One key finding is that the AOC database indicates the date an AOC was entered in the database, rather than the date it occurred, which is the more relevant of the two dates. It doesn't appear that provisions have been established to allow for trending or evaluation based on occurred date and time. **Comment**

195.402(e7) - Notification of Fire, Police, and other Public Officials. Question as to whether local emergency officials should be given a heads up in the event of a release. Possible concerns related to notification of fire and police when it may take some time to determine the extent, location, or circumstances associated with a release. **Comment**

Operation of a safety device should be an AOC. Wasn't according to procedures and discussion with Jim Johnston. This is addressed in other areas of the procedures, but not for the Control Center. **Comment**

Corrosion Records:
Discussed location at MP 1035.483 where 18 and 26 inch lines are indicated as winter reads, but don't appear to have been read, based on available information. Also discussed 1043.064C which indicates No Test Station (May be installed 2005) both in the 2005 survey data, and the 2006 survey data. Also discussed 1081.077 which has No Test Station for any of the 4 lines (Closest U/S? & D/S are one mile)

MP 1035.483 has 2004 reads for the 18 and 26 inch. 1043.064C has a test station within .1 miles, so no TS will likely be installed.

Discussed interference testing, and the need for more proactive testing among operators in Northern Minnesota.

Atmospheric corrosion inspections - exposed mainline does not have evidence of atmospheric corrosion inspections - Necktie River, MP 913, irrigation ditches MP 797, 829 (Tamarac River)

The atmospheric corrosion issue and some of the follow-up items from the annual surveys may have some level of enforcement associated with them (Letter of Concern/Warning Letter). The other items were primarily Comments that we believe need some attention.

Pending - Main Line relief info for Hans

MINNESOTA DEPARTMENT OF PUBLIC SAFETY

Department of Public Safety • State of Minnesota

State Fire Marshal and Pipeline Safety

444 Cedar Street • Suite 147 • Saint Paul, Minnesota 55101-5147
Phone: 651.201.7230 • Fax: 651.296.9641 • TTY: 651.282.6555
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October 26, 2007

Case No. **007172-1**

Mr. Ivan Huntoon
Central Region Director – PHMSA
901 Locust Street, Room 462
Kansas City, MO 64106

Subject: Enbridge Energy Company - Standard Inspection

Dear Mr. Huntoon:

Attached is a post inspection memorandum (PIM) for the field portion of the standard inspection with Enbridge Energy Company conducted September 24 - 28, 2007.

If you have any questions or need further information, please contact this office.

Prepared by,

Brian E. Pierzina ~~Brian~~ Pierzina, Senior Engineer

For the Minnesota Office of Pipeline Safety,

Darren Lemm Darren Lemmerman, Acting Chief Engineer

email: Leonard Steiner, Hans Shieh

MINNESOTA PUBLIC SAFETY STATE FIRE MARSHAL

MINNESOTA PUBLIC SAFETY PIPELINE SAFETY

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:		**Inspector/Submit Date:** Brian Pierzina 10/26/07
		Peer Reviewer/Date: 10-26-07
		Director Approval 11/13/07

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Energy Company, Inc.		**OPID #:** 11169
Name of Unit(s):	Former Lakehead System – All of Minnesota		**Unit #(s):** 3083
Records Location:	119 North 25th Street East, Superior, Wisconsin		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil & NGL		
Inspection Type:	Field & Records Inspection 420	**Inspection Date(s):** 9/24-28/2007	
For OPS :	Hans Shieh		**AFO Days:**
For MNOPS :	Brian Pierzina (9/27-28), Boyd Haugrose (9/24-26)		**AFO Days:** (5)
MNOPS CASE #: 007172			

Synopsis: This PIM primarily relates to the Field portion of the Enbridge Standard Inspection, which was conducted from September 24-28, 2007. The Office/Records portion of the inspection was conducted August 7-10, 2007. A PIM for the Office/Records portion was submitted to the Central Region on September 5, 2007. Enbridge has already responded to many of the Issues that were addressed in an October 1, 2007 letter from Patsy Bolk. This response and the MNOPS inspection form have been submitted to Hans Shieh (inspection team lead) via e-mail separately.

Summary: On September 24th, Boyd Haugrose accompanied Hans Shieh (PHMSA, Central Region) as he audited the North Dakota (ND) portion of the Enbridge Pipeline System as it enters the US. Upon completion of the ND unit, Mr. Shieh left to audit the MinnCan project and the Minnesota portion of the system began downstream of the Red River. The following individuals were part of the inspection team for Enbridge:

Jay Johnson, Compliance Coordinator
Mike Goman, Supervisor Engineering Services
John Bissell, Corrosion Control Technician
German Melendrez, Compliance Manager, OCENSA
Patsy Bolk, Compliance Analyst

The following Enbridge personnel were interviewed at their respective operations units:
Al Johnson, Electrical/Mechanical (E/M) Technician at the Donaldson Station
Corey Fkjerven, E/M Technician at the Viking Station
Tim Peterson, E/M Technician at the Viking Station
Rick Kimball, E/M Technician at the Plummer Station
Sam Sparhawk, E/M Technician at the Wilton Station
Blake Olson, Terminal Manager, Clearbrook Terminal

Upon completion of the ND unit, the team proceeded to the Donaldson Pumping Station in Minnesota. The two rectifiers were monitored and random Pipe to Soil (PS) potentials was noted throughout the site. The rectifiers were cycled on/off while PS potentials were noted. All potentials were well within acceptable criteria with the highest "on" potential noted as -1.52 VDC and highest "off" potential noted as -1.29VDC. Station pressure recordings were viewed randomly on the computer for the past 3 years. No issues were identified. Al Johnson accompanied the team to the valve settings within the operating area encompassed by the Donaldson station. Random manual valves were operated by Mr. Johnson to check for operational capability. No issues were identified.

9/25/07 BEH
The audit continued at the Viking Station where Corey Fkjerven and Tim Peterson were in attendance. The same tests with rectifiers were performed as noted at the Donaldson facility. No issues were noted as the potentials were highest at 1.62VDC "on" and 1.21 "off". No issues were noted as a result of viewing station pressures. Mr. Fkjerven accompanied the team to all of the valve sites within the operational area corresponding with the Viking station. Random manual valves were exercised, with no concerns noted.
Larry Sand, EEC Project Coordinator had a construction crew conducting a remediation dig in the middle of County Road 71 (Pennington County) as a result of a pig run. The team observed an asbestos removal technician removing the coal tar coating from the exposed pipe. The pipe is to be examined for a suspected dent as identified by the pig run. In a recent discussion with Mr. Sand it was determined that a dent was identified. The circumstances of the dent only required the pipe to be recoated, which has occurred and the road is once again open to traffic. Downstream of the Red Lake River there are 3 pipelines exposed over County Ditch Number Twenty One. This site is one that was not included in the Atmospheric Corrosion Control program that was examined during the "in office" audit in Superior, WI. The audit team hiked into the site from County Road 75 to examine the site. The pipe coating was in excellent shape on all 3 pipelines. P/S potentials were -1.25VDC at the site. No issues were identified. Enbridge will add the site to the program.

The Plummer Station is undergoing extensive renovation. Three projects are underway. The major project concerns line 4 (36 -48"). The discharge piping is being totally re-vamped, including the control valve facilities. The pump is being re-rated. While on site, the team observed contractors excavating and dismantling the unit including the building over the pump unit. This is the first in the series of all of the pumping units on line 4. The second project being done is the small diameter piping revamp. As a result of continuing leaks on small diameter piping particularly in the Clearbrook station and at the densitometer site upstream of Clearbrook, EEC has begun phasing out all small diameters piping with threaded fittings. After completion of the project in all facilities there will be no threaded pipe, unions, coupling, etc; limiting exposure to small leaks. The Plummer station is the first facility to begin the project. The 3rd project underway in Plummer is the expansion of the site to accommodate the future addition. A new dyke has been built surrounding the site, with landscaping through out the facility. One issue was noted; that being some poor coating at the soil/air interface on the discharge side of one unit. The team noted the issue, contacted the PLM crew in Thief River Falls and had them dig up the site and recoat the interface. The action was completed within 2 days and a picture has been sent to this office showing the remediation. No further concern on that issue. PS potentials were all good within the station. The audit continued on to the valve setting upstream of the Lost River in Oklee and continued to the valve setting near Trail at the crossing of State Highway 92. Rectifiers and PS potentials were noted , with no potential issues.

9/26/07 BEH
The audit continued at the Clearbrook Terminal. Accompanying the team was Blake Olson, the terminal manager. Pipe to soil potentials were taken throughout the terminal.
One discrepancy was noted. The PS potential on the firefighting piping at fire valve H-6 (M) had a potential of -.790VDC. Nearby rectifiers were cycled but no discernable shift was noted at this valve. Other tests over the firefighting piping show acceptable levels of cathodic protection. It is not clear if the entire fire piping is steel. The corrosion technician was to examine records to determine if this may be the case. This valve setting may be isolated by plastic piping. P/S potentials on piping connecting the Minnesota Pipeline (MPL) facility were checked at the isolating gaskets. EEC's potentials were -1.510VDC, while MPL's were -.770VDC. MPL is undergoing extensive revisions as part of the MinnCan project, with some of the rectifiers in their facility shut off at this time.

At this time Tank 64 is undergoing an API 653 inspection. Mark Allen is the contract Certified 653 inspector. The primary and secondary seals on the floating roof are being replaced. The foam system is being changed from a roof system to a wall system to further enhance the fire fighting potentials.

Another project underway at the terminal is the installation of electrical piping to the meter skid for unit 3. This is the preliminary phase of the project. The skid piping will begin in the near future.

While at the terminal a GE MFL tool was being launched on the 36" portion of line 4. This is the second run of this tool. The first attempt was a failure, as the pressure switch failed and the unit ran without any recording. This tool is an expandable unit and has been run on the 48" portion of line 4. The pig will run to the Cass Lake station. The team observed the launch. No concerns.

Records were checked involving monthly breakout tank inspections. No issues. Valve/relief valve inspections records were checked. Contact was made with the Edmonton Control Center and valve 2HPCV was remotely operated successfully. This is a 16" control valve on Unit 2 (26" line).

The team moved on to the Wilton Station where Sam Sparhawk (E/M Technician) accompanied the team examining the valve settings and rectifiers within the operational area of the station. No valve issues were noted and rectifiers and PS potentials were all acceptable. The audit terminated at the valve setting upstream of the Mississippi River in Bemidji. An exit interview was held within the facilities in Bemidji and the audit was turned over to MNOPS inspector Brian Pierzina to begin on 9/27 in Cass Lake.

9/27/07 BEP
The inspection began at the North Cass Lake pumping station, where Lines 1 and 2 are pumped on. Representing Enbridge were Patsy Bolk, Jay Johnson, Mike Goman, John Bissell, and German Melendrez. Jim Forbes (mechanic) and

Dave Keith (electrician) were also on-site to discuss and review station particulars. There was one rectifier at the station, which included a distributed anode bed, anode flex, and a deep well anode bed. The rectifier was only putting out 1.8 amps, which appeared to all be coming from the distributed anodes and anode flex. There didn't appear to be any current flowing through the deep well anode bed. Each junction box had a rheostat, but the corrosion technician, John Bissell, was unfamiliar with the intention or function of the design. It was installed under the direction of the previous corrosion technician. John indicated he would look into it, and make sure it was functioning as intended. No low potentials were identified during any portion of the field inspection. Following the walk-through at North Cass Lake Station, the crew proceeded to the South Cass Lake Station, where Lines 3 and 4 are pumped on. There was a dual diameter MFL tool being run from Clearbrook to Cass Lake, which was due to land at 4:00 PM. The technicians indicated the tool would be left in the trap until the following morning.

From Cass Lake, the team proceeded upstream to the crossing of the Necktie River, where the Minnesota DNR had indicated the 18 inch Line 1 was totally exposed, and poorly coated. Enbridge subsequently had inspected the pipe, and were making plans to re-coat the pipeline in the winter. We did walk out and look it over as part of the field inspection. There were no line markers at the crossing, or for a significant length of the pipeline through the swamp.

Following the river crossing inspection (and lunch), the MFL tool was nearby, so we observed the pig tracking operations at two locations in Bemidji. A geophone system was used to listen as the pig passed by, as well as an AGM reference which signaled the tool as it passed by. At the second site, which was a main line valve setting, two AGM boxes were placed 10 and 15 feet upstream of the center of the valve, which will allow for better correlation of the tool signals and distances during log analysis.

The team then proceeded to the Sucker Bay Road valve site, at MP 967, where the rectifier output was 7.9 V, and 2.35 A. The On reading for the Line 2 valve was -1.64 V, and the Off reading was -1.355 V.

The team then proceeded to the Deer River pumping station, where all four lines are pumped on. A new diking system had recently been installed. In addition, Line 2 station bypass piping had been exposed for corrosion assessments. However, this work was being done at the direction of the Bemidji PLM crew, who were busy with other functions, so no assessments were being performed at the time of the inspection.

9/28/07 BEP
The field inspection began in Grand Rapids at the Highway 169 crossing for Lines 1 and 4, and the idle Line 2 (seven mile diversion). CP On readings were -1.106, -1.152, and -1.018, respectively. The team the proceeded to the Gunn Road valve site, at MP 1012, where the auto potential rectifier was outputting 34.1V and 10.2 A. The Line 1 Blackberry pumping station was inspected next. At the time of the inspection, the Line was idle, but there was a 15 psig differential between the suction and discharge pressures (S-206 psig, D-221 psig). A check valve in the station piping keeps the pressures from equalizing. Observed Steve Newton, station electrician, perform gas monitor calibrations for the VFD building and Unit 3.

After Blackberry, the team proceeded to MP 1035, where CP test stations had been missed as part of the annual CP survey. This location was in the middle of the Wawina swamp, and recent heavy rains had raised water levels to the point that CP readings were not practical. John Bissell had gone to the site following the records portion of the audit, however, and obtained CP readings.

The field inspection continued at the Floodwood pumping station, which pumps on Lines 2, 3 and 4, and concluded at the Gowan pumping station, which pumps on Line 1. The recap consisted of a review of items identified during the audit. Patsy Bolk expected to get a letter out on 10/1 which would address the items raised during the record portion of the audit. The recap included discussions of the importance of understanding how something was designed to function (N. Cass Lake CP system), so it's apparent when it's not functioning properly. Also discussed were the need to better manage information on exposed and shallow pipelines, which Mike Goman reported they had taken to heart following the records inspection. The only other items discussed were the issues associated with lack of atmospheric corrosion inspections and line markers at the Necktie River crossing.

10/9/07 BEP
Received a hard copy response to the issues identified during the records portion of the audit from Patsy Bolk, dated October 1, 2007. The detailed response addresses each item thoroughly. The following is a summary of the Enbridge response:

The 2005 and 2006 DOT Annual reports incorrectly reported the 20" Line 1 as transporting crude, when it was predominantly NGL, and these will be revised. The inaccuracy was attributed to mis-communication, and has been addressed by implementing a new information transfer process.

Procedures 2.0, 4.0, PI-03 step 4.3, and Section 8.0 from the Pipeline Integrity Excavation Program appear to adequately address the Safety Related Condition Reporting concern. These procedures weren't presented during the audit.

As stated during the audit, training records demonstrated compliance. Enbridge will review their practices to ensure and demonstrate compliance.

AOC's can be sorted on occurred date by requesting a modification of a view in the Notes database. The sorting issue is already thought to have been addressed in FACMAN, which is the current system for recording AOC's.

A revision request has been submitted for Book 7 (Emergency Response), Section 02-02-01, to clearly require consideration for notifying local officials in each and every situation.

The response provides a number of examples of AOC's from OQ Tasks, implying that operation of a safety device would be defined as an AOC in the Field, rather than the Control Center.That appears to be a stretch, but the response goes on to indicate Enbridge is reviewing this item with the understanding that the Control Center may have first notice, so they are developing procedures for each type of safety device and how the Control Center will react to them. As part of this, the Control Center is going to include all safety device activations as AOC's.

The Main Line Relief issue actually relates to two small thermal relief valves that serve the booster pump discharge lines. A historical documentation error prior to 2006 inadvertently omitted these two valves from the paper forms, and this issue carried into 2005. The practice was for personnel to check all manifold relief valves at the Terminal at the same time, and record the checks after they were all complete. This documentation issue was identified in 2006, and corrected going forward.

The response addressed the various corrosion control issues as follows:
MP 1035.483 - test point was missed - skipped by contractor because it's a "winter read", not picked up by the corrosion technician
MP 1043.064C - no need for additional test station
MP 1081.77 - reviewing the need for and feasibility of installing additional test stations.
MP 826 - Stephen Rectifier - Information was provided indicating the rectifier was checked and/or repaired at least once per month from September through December, of 2006.
MP 831.065 - does not exist. There are test stations at MP 830.800 and 831.724. The area is a farm field. There are readings for this milepost in 2004, but John Bissell believes they were recorded in error.

Superior Region
Records Audit
August 7-10, 2007

Name	Title / Company
Patsy Bolk	Compliance Analyst - Enbridge
RANDY WILBERG	SAFETY / COMPLIANCE - SUPERIOR REGION
MIKE GOMAN	SUPERIOR REGION / ENBRIDGE
JAY JOHNSON	SR COMP COORD - ENB SUPERIOR
MARK WILLOUGHBY	GENERAL MANAGER, SUPERIOR REGION / ENBRIDGE
Brian Pierzina	Sr. Engineer / MNOPS
Boyd Haugrose	MNOPS
HANS SHIEH	DOT / PhmSA Enbridge
Donna Tribe	Compliance - Edmonton
Charmaine Rosenbaum	Manager · Human Resources
Patricia Nettleton	Payroll Coordinator
Jeff MARTIN	PTC
Gail Follis	Tech. Records Coordinator
Cynthia Clark	OQ Training Coordinator
Bill Beck	Enbridge Supervisor controls
Jarrett Kachur	Enbridge Facilities Management
TONY HOMMERDING	PLM SUPERIOR
Jim Johnston	Edmonton Control Center Enbridge
Novi Ferris	Safety & Environmental clerk
Tom PETERSON	Maximo Coordinator
John Bissell	Sr. CP Specialist
Mark JEROBEK	SR. Comm. COORD
TREVOR PLACE	CORROSION ENG. / EDMONTON

570 401 8949

Name Title
Mike Blowers Electrical Tech

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator:	
OP ID No. [1]	**Unit ID No.** [1]
H.Q. Address:	**System/Unit Name & Address:** [1]
Co. Official:	**Activity Record ID#:**
Phone No.:	**Phone No.:**
Fax No.:	**Fax No.:**
Emergency Phone No.:	**Emergency Phone No.:**

Persons Interviewed	Titles	Phone No.

PHMSA Representative(s) [1] **Inspection Date(s)** [1]

Company System Maps (copies for Region Files):

Unit Description:

~~**Portion of Unit Inspected**~~ [1] CSA closure

1) Annual Report
2) SRCR - ILI Reports
3) 573(a)(1) - CP annual CP (no T.S.)
4) Atmospheric Corrosion - 3 area's
5)

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/02/02 and 03/02/07.

[1] Information not required if included on page 1.

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CONVERSION TO SERVICE		S	U	N/A	N/C
* .5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.				

Comments:

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				
	.54(b)	Supplemental report - required within 30 days of information change/addition				
	.55	Safety-related conditions (SRC) - criteria				
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				

Comments:

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				

Comments:

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				
		Welding procedures must be qualified by destructive testing.				
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.56	Safety Related Conditions (None)			✓	
.57	Offshore Pipeline Condition Reports (No off shore)			✓	
.59	Abandoned Underwater Facility Reports (No Abandoned facilities)			✓	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification			✓	
.214(b)	Test Results to Qualify Welding Procedures			✓	
.222	Welder Qualification			✓	
.234(b)	Nondestructive Technician Qualification			✓	
.589	Cathodic Protection			✓	
.266	Construction Records			✓	
.266(a)	Total Number of Girth Welds — No New construction on these units			✓	
	Number of Welds Inspected by NDT			✓	
	Number of Welds Rejected			✓	
	Disposition of each Weld Rejected			✓	
.266(b)	Amount, Location, Cover of each Size of Pipe Installed			✓	
.266(c)	Location of each Crossing with another Pipeline			✓	
.266(d)	Location of each buried Utility Crossing			✓	
.266(e)	Location of Overhead Crossings			✓	
.266(f)	Location of each Valve and Test Station			✓	
	PRESSURE TESTING				
.310	Pipeline Test Record	✓			
.305(b)	Manufacturer Testing of Components				
.308	Records of Pre-tested Pipe	✓			
	OPERATION & MAINTENANCE				
.402(a)	Annual Review of O&M Manual (1 per yr/15 months)	✓			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	✓			
* .402(c)(10)	Abandonment of Facilities			✓	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	✓			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures Possibly	✓			
.402(d)(1)	Response to Abnormal Pipeline Operations ? Tie OQ to this??				
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	?			
.402(e)(1)	Notices which require immediate response	✓			
None in ND .402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency Review written Incident	?			
.402(e)(9)	Post Accident Reviews	✓			
.403(a)	Emergency Response Personnel Training Program	✓			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (1 per yr/15 months)	✓			

→ They have idle lines (Nitrogen) Doc. for OM+P and

→ They do have technical committee's that meet and are chairs of the O&M review

They also have "Grass root's" safety [illegible] incentive. Committee [illegible]

HVL-Batching => 50%

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	✓			
.404(a)(1)	Maps or Records of Pipeline System	✓			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	✓			
.404(a)(3)	MOP of each Pipeline	✓			
.404(a)(4)	Pipeline Specifications	✓			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	✓			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	✓			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	✓			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	✓			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	✓			
.406(a)	Establishing the MOP	✓			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	✓			
.412(a)	Inspection of the ROW	✓			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	✓			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			✓	
.420(b)	Inspection of Mainline Valves	✓			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	✓			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE 5 yrs). (Only in			✓	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	✓			
.430	Inspection of Fire Fighting Equipment	✓		ok for MN	
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**). (No Tanks in ND)	✓			
.440	Public Education/Awareness Program	✓			
DAMAGE PREVENTION PROGRAM					
.442(c)(1)	List of Current Excavators	✓			
.442(c)(2)	Notification of Public/Excavators	✓			
.442(c)(3)	Notifications of planned excavations. (One -Call Records) Non for ND	✓			
CORROSION CONTROL					
.555	Supervisors maintain thorough knowledge of corrosion procedures.	✓			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	✓			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	✓			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)		✓		
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	✓			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)			✓	
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	✓			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	✓			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	✓			

Comment about procedure

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.589(c)/.575	Electrical isolation inspection and testing	✓			
.589(c)/.577	Testing for Interference Currents (Make Comment) – Discuss	✓			
.589(c)/.579(a)	Corrosive effect investigation	✓			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (2 per yr/7½ months) No coupons in ND	✓			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	✓			
.589(c)/.583(a)	Atmos. Corr. Monitoring (1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)		✓		
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	✓			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	✓			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	✓			

Comments:

X-over @ Joliet Sta.
+ info is ok.

cx

2 — 3 months?

E826.04-700-
CR-826
9/20/2006
12/19/2006

/erode batching
'ominate use determines
' they report on Annual Report
...ld flip/flop??

One exposed pipe not MP797
evaluated in 2006. in ND.
Probably done in 2003

Tamarac
Tamarac River
MP829

cl

04 there was a read

4 — ?

831.065

No T.L. for 05 + 06

Rev. 03/02/07 through Amdt. 195-86).

Nori Ferris - Safety & Environment Clerk

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	✓		
194.111	RSPA Tracking Number: 866, 867, 1666, 1665, 701, 702 Approval Date: 2/95 Emergency Response Guide	✓		
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	✓		Is reference in OPA Plan
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3] Bay West + Garner	✓		
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4] See table top drill	✓		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	✓		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note)*:
Just sent in revisions on 7/18/07 | Superior Region did 4 deployments in 2006

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the Asequence number.@ It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

Enbridge Oil spill response database

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill. quarterly drills OK 2006-7

ask Randy or Jim

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

ok

619
62
681

344 out
of Clear brook

1) Northern Border Const
2)

Annual Report

2006 Reports: Report on 20" ⇒ Reported for Crude not NGL?
If Line is Batched; which do you file under

Telephones: Can they do it on-line?
Leonard says no.

SRCRS -? ICF Reports - Discovery - MNOPS w/ note.

Damage Prevention Meetings in 3 areas in ND

Line 1 6/7/07 - about 1730 mst - Joliet Possible AOC -

AOC ⇒ How do they trend?
Communication failure? 5 mins no communications

Station
Joliet
Viking
~~Donaldson Plummer~~
Donald Son
Viking : Discharges into 36 742
Plummer
Clearbrook
Wilton
Cass Lake
Deer River
Black berry
Floodwood
Cowan

833
83
916

L3 Donald Son 4-10/06 Increase 100 psig
L4 Deer River 4-10/06 ~~[illegible]~~ decrease 973 to 880
L3 Flood Wood 4-10/06 Increase 560 to 636

CR-910-PSE-100
CR-225-PSU-16
CR-225-PSU-17

Enbridge Energy – Superior Region Records Audit – August 7-10, 2007
Brian Pierzina, Boyd Haugrose & Hans Shieh – Inspectors

Thanks for your preparation and coordination during the audit. The following are comments related to unsatisfactory or pending issues, and areas we discussed where potential improvements may enhance your existing programs.

195.49 Annual Reports – The 2005 Annual Report indicates 190 miles of HVL pipeline total. Speculation is that this would be the 18 inch from Clearbrook to Superior. There is nothing reported for HVL pipeline upstream of Clearbrook, even though the 20 inch is predominantly NGL from the Canadian Border to Clearbrook. Question as to the procedures for completing the Annual Report, and how the person compiling the information determines whether a pipeline that transports both crude and HVL is distinguished as either HVL or crude. Patsy will obtain volumes for 2005 and 2006 for the 20 inch and 18 inch. The 190 miles of HVL reported is for the 18 inch downstream of Clearbrook. **Pending**

195.56 SRCR – Discovery is not well defined as it pertains to receipt of ILI anomalies from a tool vendor. There is a belief that the initial report should trigger the discovery clock, but other opinions have also been offered. The operator's procedures do not address this. **Possible NOA item – although it would not likely be issued if procedures addressed discovery prior to preparation of the inspection report.**

195.403(b) – Records indicated some individuals exceeded the 15 month requirement for tabletop exercises, although it appears there may have been two sessions attended during 2006 with the latter overwriting the former, consequently appearing that some individuals have exceeded the 15 month requirements. Recordkeeping function may need to be modified so that compliance with the interval requirement can be more easily demonstrated. **Comment**

AOC's – Reviewed AOC database w/Jim Johnston via telephone. One key finding is that the AOC database indicates the date an AOC was entered in the database, rather than the date it occurred, which is the more relevant of the two dates. It doesn't appear that provisions have been established to allow for trending or evaluation based on occurred date and time. **Comment**

195.402(e7) – Notification of Fire, Police, and other Public Officials. Question as to whether local emergency officials should be given a heads up in the event of a release. Possible concerns related to notification of fire and police when it may take some time to determine the extent, location, or circumstances associated with a release. Also, include provisions for courtesy calls when assistance is not required, but to give the officials a heads up. **Comment**

Operation of a safety device should be an AOC. Wasn't according to procedures and discussion with Jim Johnston. This is addressed in other areas of the procedures, but not for the Control Center. **Comment**

Corrosion Records:
Discussed location at MP 1035.483 where 18 and 26 inch lines are indicated as winter reads, but don't appear to have been read, based on available information. Also discussed 1043.064C which indicates No Test Station (May be installed 2005) both in the 2005 survey data, and the 2006 survey data. Also discussed 1081.077 which has No Test Station for any of the 4 lines (Closest U/S? & D/S are one mile)

MP 1035.483 has 2004 reads for the 18 and 26 inch. 1043.064C has a test station within .1 miles, so no TS will likely be installed.

Discussed interference testing, and the need for more proactive testing and coordination among operators in Northern Minnesota.

Atmospheric corrosion inspections – exposed mainline does not have evidence of atmospheric corrosion inspections – Necktie River, MP 913, irrigation ditches MP 797, 829 (Tamarac River)

The atmospheric corrosion issue and some of the follow-up items from the annual surveys may have some level of enforcement associated with them (Letter of Concern/Warning Letter). The other items were primarily Comments that we believe need some attention.

Pending – Main Line relief info for Hans

PS – I didn't go over this with Boyd and Hans. I hope I didn't forget anything too important. If I did, it's inspector prerogative to add it back in.

Thanks,
Brian

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: Enbridge Energy, Limited Partnership	
OP ID No. [1] **11169**	**Unit ID No.** [1] **3083**
H.Q. Address:	**System/Unit Name & Address:** [1]
Enbridge Energy, Limited Partnership 1100 Louisiana, Suite 3300 Houston TX 77002	PO Box 665 1103 Roosevelt Rd. Bemidji, MN 56601
Co. Official: Terrence McGill	**Activity Record ID#:** 119028
Phone No.: 713-821-2003	**Phone No.:**
Fax No.:	**Fax No.:**
Emergency Phone No.: 713-410-4767	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Patsy Bolk	Compliance Analyst I	715-394-1504
Jay Johnson	Senior Compliance Coordinator	715-394-1512
Randy Wilberg	Safety, Training and Compliance Coordinator	715-394-1412
Mike Goman	Supervisor, Regional Engineering and Services	715-394-1523
Mark Willoughby	General Manager, Superior Region	715-394-1534

PHMSA Representative(s) [1] Brian Pierzina – MN-OPS; Boyd Haugrose – MN-OPS **Inspection Date(s)** [1] **:** 8/6-10/2007; 9/24-28/2007

Company System Maps (copies for Region Files):

Unit Description:

The unit consists of gun barrel 18, 20, 26, and 34 inch lines, and then a combination 36/48 inch (Line 4) from the ND/MN border to Clearbrook. From Clearbrook to Superior they have all the same, except they don't have the 20 inch. The 18 inch from Clearbrook to Superior is NGL.

Portion of Unit Inspected [1]

The entire unit was inspected.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/02/02 and 03/02/07.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

CONVERSION TO SERVICE		S	U	N/A	N/C
* .5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				X
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
Team O&M conducted in May of 2006.

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
Team O&M conducted in May of 2006.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				X
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				X
		Welding procedures must be qualified by destructive testing.				X
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

CONVERSION TO SERVICE		S	U	N/A	N/C
* .5	Has a written procedure been developed addressing all applicable requirements and followed? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)).				X
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
Team O&M conducted in May of 2006.

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
Team O&M conducted in May of 2006.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				X
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				X
		Welding procedures must be qualified by destructive testing.				X
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				X
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with ' **195.302**.				X
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2004 Ed. Including addenda through July 1, 2005), except that a welder qualified under an earlier edition than listed in **' 195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 195-81 corr. Pub. 9/09/04; Amt 195-86 pub 06/09/06 eff 07/10/06.				X
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	**.226(a)**	Arc burns must be repaired.				X
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate).** Pipe must be removed for non-repairable notches.				X
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				X
	Nondestructive Testing Procedures					
*	**.228 /.234**	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **' 195.228(b)** and per the requirements of **' 195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				X
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				X
		2. By qualified personnel				X
		3. By a process that will indicate any defects that may affect the integrity of the weld				X
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				X
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				

Comments:
Team O&M conducted in May of 2006.

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	**.302(a)**	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions).				X
	.302(b)	Except for lines converted under **' 195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				X
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in ' 195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				X
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				X

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		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				X
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with **' 195.302**.				X
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
*	**.310(b)(10)**	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	**.402**	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	**.402(c)**	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				X
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				X
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				X
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **' 195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				X
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **' 195.406**?				X
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **' 195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				X
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				X
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59.				X
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				X
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				X
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				X
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				X

Comments:
Team O&M conducted in May of 2006.

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	**.402(d)**	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				X
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				X
		iii. Loss of communications?				X
		iv. The operation of any safety device?				X
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:
Team O&M conducted in May of 2006.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:
Team O&M conducted in May of 2006.

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:
Team O&M conducted in May of 2006.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:
Team O&M conducted in May of 2006.

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				X
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				X
	.403(b)(2)	Make appropriate changes to the emergency response training program				X
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				X

Comments:
Team O&M conducted in May of 2006.

MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				X
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				X
		ii. Pump stations				X
		iii. Scraper and sphere facilities				X
		iv. Pipeline valves				X
		v. Facilities to which ' **195.402(c)(9)** applies				X
		vi. Rights-of-way				X
		vii. Safety devices to which ' **195.428** applies				X
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				X
	.404(a)(3)	The maximum operating pressure of each pipeline.				X
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				X
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				X
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under ' **195.402** apply.				X
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				X
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				X
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	.406(a)(1)	The internal design pressure of the pipe determined by ' **195.106**. Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	**80%** of the test pressure (**Subpart E**).				X
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
Team O&M conducted in May of 2006.

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by ' **195.402(c)(9)**.				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
Team O&M conducted in May of 2006.

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
*	.406(a)(1)	The internal design pressure of the pipe determined by ' **195.106**. Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				X
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
Team O&M conducted in May of 2006.

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by ' **195.402(c)(9)**.				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
Team O&M conducted in May of 2006.

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				X
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 **years**.				X

Comments:
Team O&M conducted in May of 2006.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				X
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				X

Comments:
Team O&M conducted in May of 2006.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				X
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **72 months**, but at least **twice** each calendar year.				X
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				X

Comments:
. Team O&M conducted in May of 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
Team O&M conducted in May of 2006.

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under **' 195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under **' 195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
Team O&M conducted in May of 2006.

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:
Team O&M conducted in May of 2006.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
Team O&M conducted in May of 2006.

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
Team O&M conducted in May of 2006.

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:
Team O&M conducted in May of 2006.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				X
		2. **HVL** pipelines at intervals not to exceed **72 months**, but at least **twice** each calendar year.				X
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				X
*	**.428(c)**	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Amt 195-86 pub 06/09/06 eff 07/10/06. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				X
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				X

Comments:
Team O&M conducted in May of 2006.

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	**.430**	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				X
		The equipment must be:				
		a. In proper operating condition at all times.				X
		b. Plainly marked so that its identity as firefighting equipment is clear.				X
		c. Located so that it is easily accessible during a fire.				X

Comments:
Team O&M conducted in May of 2006.

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	**.432(a)**	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				X
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **' 195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				X
*	**.432(c)**	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X

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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
Team O&M conducted in May of 2006.

		SIGN PROCEDURES	S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
*		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
Team O&M conducted in May of 2006.

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:
Team O&M conducted in May of 2006.

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				X

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
Team O&M conducted in May of 2006.

		SIGN PROCEDURES	S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
*		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
Team O&M conducted in May of 2006.

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
Team O&M conducted in May of 2006.

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:
Team O&M conducted in May of 2006.

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a) *	.440	Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				X

Comments:

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Comments:
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		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				X
	.442(b)	Does the operator participate in a qualified One-Call program?				X
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				X
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				X
		ii. How to learn the location of underground pipelines before excavation activities are begun.				X
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				X
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				X
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				X
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				X
		ii. In the case of blasting, any inspection must include leakage surveys.				X

Comments:
Team O&M conducted in May of 2006.

		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a) *	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training? Amt 195-86 pub 06/09/06 eff 07/10/06.				X

Comments:
Team O&M conducted in May of 2006.

	PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES	S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

	SUBPART G - OPERATOR QUALIFICATION PROCEDURES	S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**?				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X
*	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2002** (incorporated by reference). Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**.				X
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.				X
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-2002.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**?				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X
*	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2002** (incorporated by reference). Amt 195-86 pub 06/09/06 eff 07/10/06.				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**.				X
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.				X
*		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-2002.** Amt 195-86 pub 06/09/06 eff 07/10/06.				X

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		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				X
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				X
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 22 mos.**				X
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				X
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b).**				X
	.575	Are there adequate provisions for electrical isolations?				X
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				X
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				X
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				X
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 2 months.**				X
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				X
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				X
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				X
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				X
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				X
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				X
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**				X
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				X

Comments:
Team O&M conducted in May of 2006.

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PART 195 - FIELD REVIEW		S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory				X
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers		X		
.412	ROW/Crossing Under Navigable Waters	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings – Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks			X	
.434	Signs - Pumping Stations - Breakout Tanks	X			
.436	Security - Pumping Stations - Breakout Tanks	X			
.438	No Smoking Signs	X			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.575	Electrical Isolation; shorted casings	X			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)		X		

PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
CONVERSION TO SERVICE					
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
REPORTING					
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)		X		

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PART 195 - FIELD REVIEW		S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory				X
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers		X		
.412	ROW/Crossing Under Navigable Waters	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings – Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks			X	
.434	Signs - Pumping Stations - Breakout Tanks	X			
.436	Security - Pumping Stations - Breakout Tanks	X			
.438	No Smoking Signs	X			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.575	Electrical Isolation; shorted casings	X			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)		X		

PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
CONVERSION TO SERVICE					
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
REPORTING					
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)		X		

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PART 195 - PERFORMANCE AND RECORDS REVIEW		S	U	N/A	N/C
.52	Telephonic Reports to NRC (800-424-8802)	X			
.54(a)	Written Accident Reports (DOT Form 7000-1)	X			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	X			
.56	Safety Related Conditions	X			
.57	Offshore Pipeline Condition Reports			X	
.59	Abandoned Underwater Facility Reports			X	
CONSTRUCTION					
.204	Construction Inspector Training/Qualification			X	
.214(b)	Test Results to Qualify Welding Procedures			X	
.222	Welder Qualification			X	
.234(b)	Nondestructive Technician Qualification			X	
.589	Cathodic Protection			X	
.266	Construction Records			X	
.266(a)	Total Number of Girth Welds			X	
	Number of Welds Inspected by NDT			X	
	Number of Welds Rejected			X	
	Disposition of each Weld Rejected			X	
.266(b)	Amount, Location, Cover of each Size of Pipe Installed			X	
.266(c)	Location of each Crossing with another Pipeline			X	
.266(d)	Location of each buried Utility Crossing			X	
.266(e)	Location of Overhead Crossings			X	
.266(f)	Location of each Valve and Test Station			X	
PRESSURE TESTING					
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			
.308	Records of Pre-tested Pipe	X			
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities	X			
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)				
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			X	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	X			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			
.440	Public Education/Awareness Program	X			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)		X		
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)			X	

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	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)				
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			X	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	X			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			
.440	Public Education/Awareness Program	X			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)		X		
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)			X	

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	X			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (**2 per yr/7½ months**)	X			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)		X		
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:

195.49 Annual Reports – The 2005 Annual Report indicates 190 miles of HVL pipeline total. Speculation is that this would be the 18 inch from Clearbrook to Superior. There is nothing reported for HVL pipeline upstream of Clearbrook, even though the 20 inch is predominantly NGL from the Canadian Border to Clearbrook. Question as to the procedures for completing the Annual Report, and how the person compiling the information determines whether a pipeline that transports both crude and HVL is distinguished as either HVL or crude. Patsy will obtain volumes for 2005 and 2006 for the 20 inch and 18 inch. The 190 miles of HVL reported is for the 18 inch downstream of Clearbrook. In Patsy's follow-up letter, they indicated that the Reports would be revised to reflect that the 20" line 1 mileage, since it predominantly transports HVL's, instead of crude.

AOC's – Reviewed AOC database w/Jim Johnston via telephone. One key finding is that the AOC database indicates the date an AOC was entered in the database, rather than the date it occurred, which is the more relevant of the two dates. It doesn't appear that provisions have been established to allow for trending or evaluation based on occurred date and time.

195.402(e7) – Notification of Fire, Police, and other Public Officials. Question as to whether local emergency officials should be given a heads up in the event of a release. Possible concerns related to notification of fire and police when it may take some time to determine the extent, location, or circumstances associated with a release. Also, include provisions for courtesy calls when assistance is not required, but to give the officials a heads up.

Corrosion Records:
Discussed location at MP 1035.483 where 18 and 26 inch lines are indicated as winter reads, but don't appear to have been read, based on available information. Also discussed 1043.064C which indicates No Test Station (May be installed 2005) both in the 2005 survey data, and the 2006 survey data. Also discussed 1081.077 which has No Test Station for any of the 4 lines (Closest U/S? & D/S are one mile)

MP 1035.483 has 2004 reads for the 18 and 26 inch. 1043.064C has a test station within .1 miles, so no TS will likely be installed.

Discussed interference testing, and the need for more proactive testing among operators in Northern Minnesota.

Atmospheric corrosion inspections – exposed mainline does not have evidence of atmospheric corrosion inspections – Necktie River, MP 913, irrigation ditches MP 797, 829 (Tamarac River)

Field Inspection Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

Comments:

195.308 – Pre-Tested Pipe – At Bemidji PLM facility – not visited as part of the field inspection.

195.410 ROW Markers – In general, the ROW is marked very well. However, where we walked into the Necktie River Crossing, there were no markers beyond the point we parked for a considerable distance downstream, including the river crossing. We walked in approximately ½ mile, with no markers, and none could be seen downstream of the river crossing for as far as we could see, which was another approximate half mile. Enbridge personnel noted this, and will be installing additional line markers.

195.432 – Breakout Tanks – None within BEP's inspection units.

195.583 – Atmospheric Corrosion – Exposed Necktie River crossing has no coating over much of its length. Enbridge has not established a method for conducting atmospheric corrosion inspections for exposed pipe in these types of circumstances. They will be addressing the overall problem, and have plans to re-coat the Necktie River crossing (18 inch Line 1) this winter.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
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Comments:

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	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	X		
194.111	RSPA Tracking Number: **866,867,1666,665,70 1702** Approval Date: **February 95**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	X		
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	X		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*

Enbridge has just sent in revisions dated 7/18/2007.

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the Asequence number.@ It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

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:		**Inspector/Submit Date:** Brian Pierzina 9/5/07
		Peer Reviewer/Date:
		Director Approval 11/13/07

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Company, Inc.		**OPID #:** 11169
Name of Unit(s):	Former Lakehead System – All of Minnesota		**Unit #(s):** 3083
Records Location:	119 North 25th Street East, Superior, Wisconsin		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil and NGL		
Inspection Type:	Field & Records Inspection 420	**Inspection Date(s):** 8/6-10/2007	
For OPS :	Hans Shieh		**AFO Days:** (5)
For MNOPS :	Brian Pierzina (8/7-10/07), Boyd Haugrose (8/6-10/07)		**AFO Days:** (9)
MNOPS CASE #: 007172			

Synopsis:

The 2007 Enbridge Standard Inspection was conducted by Brian Pierzina and Boyd Haugrose, from MNOPS, and Hans Shieh from Central Region. Participating from Enbridge were primarily Patsy Bolk, Jay Johnson, Mike Goman, Randy Wilburg and Mark Willoughby. Other Enbridge representatives participated within their areas of expertise.

The records portion of the inspection began Tuesday, August 7, 2007 at the Superior Office, and concluded Friday, August 10, 2007. The field portion of the inspection is scheduled to begin Monday, September 24, 2007, starting with the North Dakota portion of the system. The complete inspection report will be submitted following completion of the field portion of the audit.

The following items were covered in the recap session with Enbridge representatives on Friday, August 10th:

Thanks for your preparation and coordination during the audit. The following are comments related to unsatisfactory or pending issues, and areas we discussed where potential improvements may enhance your existing programs.

195.49 Annual Reports - The 2005 Annual Report indicates 190 miles of HVL pipeline total. Speculation is that this would be the 18 inch from Clearbrook to Superior. There is nothing reported for HVL pipeline upstream of Clearbrook, even though the 20 inch is predominantly NGL from the Canadian Border to Clearbrook. Question as to the procedures for completing the Annual Report, and how the person compiling the information determines whether a pipeline that transports both crude and HVL is distinguished as either HVL or crude. Patsy will obtain volumes for 2005 and 2006 for the 20 inch and 18 inch. The 190 miles of HVL reported is for the 18 inch downstream of Clearbrook. **Pending**

195.56 Safety Related Condition Reporting - Discovery is not well defined as it pertains to receipt of ILI anomalies from a tool vendor. There is a belief that the initial report should trigger the discovery clock, but other opinions have also been offered. The operator's procedures do not address this. **Possible NOA item** - although it would not likely be issued if procedures addressed discovery prior to preparation of the inspection report.

195.403(b) - Records indicated some individuals exceeded the 15 month requirement for tabletop exercises, although it appears there may have been two sessions attended during 2006 with the latter overwriting the former, consequently appearing that some individuals have exceeded the 15 month requirements. Recordkeeping function may need to be modified so that compliance with the interval requirement can be more easily demonstrated. **Comment**

AOC's - Reviewed AOC database w/Jim Johnston via telephone. One key finding is that the AOC database indicates the date an AOC was entered in the database, rather than the date it occurred, which is the more relevant of the two dates. It doesn't appear that provisions have been established to allow for trending or evaluation based on occurred date and time. **Comment**

195.402(e7) - Notification of Fire, Police, and other Public Officials. Question as to whether local emergency officials should be given a heads up in the event of a release. Possible concerns related to notification of fire and police when it may take some time to determine the extent, location, or circumstances associated with a release. **Comment**

Operation of a safety device should be an AOC. Wasn't according to procedures and discussion with Jim Johnston. This is addressed in other areas of the procedures, but not for the Control Center. **Comment**

Corrosion Records:
Discussed location at MP 1035.483 where 18 and 26 inch lines are indicated as winter reads, but don't appear to have been read, based on available information. Also discussed 1043.064C which indicates No Test Station (May be installed 2005) both in the 2005 survey data, and the 2006 survey data. Also discussed 1081.077 which has No Test Station for any of the 4 lines (Closest U/S? & D/S are one mile)

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Discussed interference testing, and the need for more proactive testing among operators in Northern Minnesota.

Atmospheric corrosion inspections - exposed mainline does not have evidence of atmospheric corrosion inspections - Necktie River, MP 913, irrigation ditches MP 797, 829 (Tamarac River)

The atmospheric corrosion issue and some of the follow-up items from the annual surveys may have some level of enforcement associated with them (Letter of Concern/Warning Letter). The other items were primarily Comments that we believe need some attention.

Pending - Main Line relief info for Hans

MINNESOTA DEPARTMENT OF PUBLIC SAFETY

State Fire Marshal and Pipeline Safety

444 Cedar Street • Suite 147 • Saint Paul, Minnesota 55101-5147
Phone: 651.201.7230 • Fax: 651.296.9641 • TTY: 651.282.6555
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October 26, 2007

Case No. **007172-1**

Mr. Ivan Huntoon
Central Region Director – PHMSA
901 Locust Street, Room 462
Kansas City, MO 64106

Subject: Enbridge Energy Company - Standard Inspection

Dear Mr. Huntoon:

Attached is a post inspection memorandum (PIM) for the field portion of the standard inspection with Enbridge Energy Company conducted September 24 - 28, 2007.

If you have any questions or need further information, please contact this office.

Prepared by,

~~Brian~~ Pierzina, Senior Engineer

For the Minnesota Office of Pipeline Safety,

Darren Lemmerman, Acting Chief Engineer

email: Leonard Steiner, Hans Shieh

Post Inspection Memorandum (PIM)

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Brian E. Pierzina

Inspection Report		Post Inspection Memorandum
Inspector/Submit Date:		**Inspector/Submit Date:** Brian Pierzina 10/26/07
		Peer Reviewer/Date: 10-26-07
		Director Approval 11/13/07

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:** 11169	
Name of Unit(s):	Former Lakehead System – All of Minnesota	**Unit #(s):** 3083	
Records Location:	119 North 25th Street East, Superior, Wisconsin		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil & NGL		
Inspection Type:	Field & Records Inspection 420	**Inspection Date(s):** 9/24-28/2007	
For OPS :	Hans Shieh	**AFO Days:**	
For MNOPS :	Brian Pierzina (9/27-28), Boyd Haugrose (9/24-26)	**AFO Days:** (5)	
MNOPS CASE #: 007172			

Synopsis: This PIM primarily relates to the Field portion of the Enbridge Standard Inspection, which was conducted from September 24-28, 2007. The Office/Records portion of the inspection was conducted August 7-10, 2007. A PIM for the Office/Records portion was submitted to the Central Region on September 5, 2007. Enbridge has already responded to many of the Issues that were addressed in an October 1, 2007 letter from Patsy Bolk. This response and the MNOPS inspection form have been submitted to Hans Shieh (inspection team lead) via e-mail separately.

Summary: On September 24th, Boyd Haugrose accompanied Hans Shieh (PHMSA, Central Region) as he audited the North Dakota (ND) portion of the Enbridge Pipeline System as it enters the US. Upon completion of the ND unit, Mr. Shieh left to audit the MinnCan project and the Minnesota portion of the system began downstream of the Red River. The following individuals were part of the inspection team for Enbridge:

Jay Johnson, Compliance Coordinator
Mike Goman, Supervisor Engineering Services
John Bissell, Corrosion Control Technician
German Melendrez, Compliance Manager, OCENSA
Patsy Bolk, Compliance Analyst

The following Enbridge personnel were interviewed at their respective operations units:
Al Johnson, Electrical/Mechanical (E/M) Technician at the Donaldson Station
Corey Fkjerven, E/M Technician at the Viking Station
Tim Peterson, E/M Technician at the Viking Station
Rick Kimball, E/M Technician at the Plummer Station
Sam Sparhawk, E/M Technician at the Wilton Station
Blake Olson, Terminal Manager, Clearbrook Terminal

Upon completion of the ND unit, the team proceeded to the Donaldson Pumping Station in Minnesota. The two rectifiers were monitored and random Pipe to Soil (PS) potentials was noted throughout the site. The rectifiers were cycled on/off while PS potentials were noted. All potentials were well within acceptable criteria with the highest "on" potential noted as -1.52 VDC and highest "off" potential noted as -1.29VDC. Station pressure recordings were viewed randomly on the computer for the past 3 years. No issues were identified. Al Johnson accompanied the team to the valve settings within the operating area encompassed by the Donaldson station. Random manual valves were operated by Mr. Johnson to check for operational capability. No issues were identified.

9/25/07 BEH
The audit continued at the Viking Station where Corey Fkjerven and Tim Peterson were in attendance. The same tests with rectifiers were performed as noted at the Donaldson facility. No issues were noted as the potentials were highest at 1.62VDC "on" and 1.21 "off". No issues were noted as a result of viewing station pressures. Mr. Fkjerven accompanied the team to all of the valve sites within the operational area corresponding with the Viking station. Random manual valves were exercised, with no concerns noted.
Larry Sand, EEC Project Coordinator had a construction crew conducting a remediation dig in the middle of County Road 71 (Pennington County) as a result of a pig run. The team observed an asbestos removal technician removing the coal tar coating from the exposed pipe. The pipe is to be examined for a suspected dent as identified by the pig run. In a recent discussion with Mr. Sand it was determined that a dent was identified. The circumstances of the dent only required the pipe to be recoated, which has occurred and the road is once again open to traffic. Downstream of the Red Lake River there are 3 pipelines exposed over County Ditch Number Twenty One. This site is one that was not included in the Atmospheric Corrosion Control program that was examined during the "in office" audit in Superior, WI. The audit team hiked into the site from County Road 75 to examine the site. The pipe coating was in excellent shape on all 3 pipelines. P/S potentials were -1.25VDC at the site. No issues were identified. Enbridge will add the site to the program.

The Plummer Station is undergoing extensive renovation. Three projects are underway. The major project concerns line 4 (36 -48"). The discharge piping is being totally re-vamped, including the control valve facilities. The pump is being re-rated. While on site, the team observed contractors excavating and dismantling the unit including the building over the pump unit. This is the first in the series of all of the pumping units on line 4. The second project being done is the small diameter piping revamp. As a result of continuing leaks on small diameter piping particularly in the Clearbrook station and at the densitometer site upstream of Clearbrook, EEC has begun phasing out all small diameters piping with threaded fittings. After completion of the project in all facilities there will be no threaded pipe, unions, coupling, etc; limiting exposure to small leaks. The Plummer station is the first facility to begin the project. The 3rd project underway in Plummer is the expansion of the site to accommodate the future addition. A new dyke has been built surrounding the site, with landscaping through out the facility. One issue was noted; that being some poor coating at the soil/air interface on the discharge side of one unit. The team noted the issue, contacted the PLM crew in Thief River Falls and had them dig up the site and recoat the interface. The action was completed within 2 days and a picture has been sent to this office showing the remediation. No further concern on that issue. PS potentials were all good within the station. The audit continued on to the valve setting upstream of the Lost River in Oklee and continued to the valve setting near Trail at the crossing of State Highway 92. Rectifiers and PS potentials were noted , with no potential issues.

9/26/07 BEH
The audit continued at the Clearbrook Terminal. Accompanying the team was Blake Olson, the terminal manager. Pipe to soil potentials were taken throughout the terminal.
One discrepancy was noted. The PS potential on the firefighting piping at fire valve H-6 (M) had a potential of -.790VDC. Nearby rectifiers were cycled but no discernable shift was noted at this valve. Other tests over the firefighting piping show acceptable levels of cathodic protection. It is not clear if the entire fire piping is steel. The corrosion technician was to examine records to determine if this may be the case. This valve setting may be isolated by plastic piping. P/S potentials on piping connecting the Minnesota Pipeline (MPL) facility were checked at the isolating gaskets. EEC's potentials were -1.510VDC, while MPL's were -.770VDC. MPL is undergoing extensive revisions as part of the MinnCan project, with some of the rectifiers in their facility shut off at this time.

At this time Tank 64 is undergoing an API 653 inspection. Mark Allen is the contract Certified 653 inspector. The primary and secondary seals on the floating roof are being replaced. The foam system is being changed from a roof system to a wall system to further enhance the fire fighting potentials.

Another project underway at the terminal is the installation of electrical piping to the meter skid for unit 3. This is the preliminary phase of the project. The skid piping will begin in the near future.

While at the terminal a GE MFL tool was being launched on the 36" portion of line 4. This is the second run of this tool. The first attempt was a failure, as the pressure switch failed and the unit ran without any recording. This tool is an expandable unit and has been run on the 48" portion of line 4. The pig will run to the Cass Lake station. The team observed the launch. No concerns.

Records were checked involving monthly breakout tank inspections. No issues. Valve/relief valve inspections records were checked. Contact was made with the Edmonton Control Center and valve 2HPCV was remotely operated successfully. This is a 16" control valve on Unit 2 (26" line).

The team moved on to the Wilton Station where Sam Sparhawk (E/M Technician) accompanied the team examining the valve settings and rectifiers within the operational area of the station. No valve issues were noted and rectifiers and PS potentials were all acceptable. The audit terminated at the valve setting upstream of the Mississippi River in Bemidji. An exit interview was held within the facilities in Bemidji and the audit was turned over to MNOPS inspector Brian Pierzina to begin on 9/27 in Cass Lake.

9/27/07 BEP
The inspection began at the North Cass Lake pumping station, where Lines 1 and 2 are pumped on. Representing Enbridge were Patsy Bolk, Jay Johnson, Mike Goman, John Bissell, and German Melendrez. Jim Forbes (mechanic) and

Dave Keith (electrician) were also on-site to discuss and review station particulars. There was one rectifier at the station, which included a distributed anode bed, anode flex, and a deep well anode bed. The rectifier was only putting out 1.8 amps, which appeared to all be coming from the distributed anodes and anode flex. There didn't appear to be any current flowing through the deep well anode bed. Each junction box had a rheostat, but the corrosion technician, John Bissell, was unfamiliar with the intention or function of the design. It was installed under the direction of the previous corrosion technician. John indicated he would look into it, and make sure it was functioning as intended. No low potentials were identified during any portion of the field inspection. Following the walk-through at North Cass Lake Station, the crew proceeded to the South Cass Lake Station, where Lines 3 and 4 are pumped on. There was a dual diameter MFL tool being run from Clearbrook to Cass Lake, which was due to land at 4:00 PM. The technicians indicated the tool would be left in the trap until the following morning.

From Cass Lake, the team proceeded upstream to the crossing of the Necktie River, where the Minnesota DNR had indicated the 18 inch Line 1 was totally exposed, and poorly coated. Enbridge subsequently had inspected the pipe, and were making plans to re-coat the pipeline in the winter. We did walk out and look it over as part of the field inspection. There were no line markers at the crossing, or for a significant length of the pipeline through the swamp.

Following the river crossing inspection (and lunch), the MFL tool was nearby, so we observed the pig tracking operations at two locations in Bemidji. A geophone system was used to listen as the pig passed by, as well as an AGM reference which signaled the tool as it passed by. At the second site, which was a main line valve setting, two AGM boxes were placed 10 and 15 feet upstream of the center of the valve, which will allow for better correlation of the tool signals and distances during log analysis.

The team then proceeded to the Sucker Bay Road valve site, at MP 967, where the rectifier output was 7.9 V, and 2.35 A. The On reading for the Line 2 valve was -1.64 V, and the Off reading was -1.355 V.

The team then proceeded to the Deer River pumping station, where all four lines are pumped on. A new diking system had recently been installed. In addition, Line 2 station bypass piping had been exposed for corrosion assessments. However, this work was being done at the direction of the Bemidji PLM crew, who were busy with other functions, so no assessments were being performed at the time of the inspection.

9/28/07 BEP
The field inspection began in Grand Rapids at the Highway 169 crossing for Lines 1 and 4, and the idle Line 2 (seven mile diversion). CP On readings were -1.106, -1.152, and -1.018, respectively. The team the proceeded to the Gunn Road valve site, at MP 1012, where the auto potential rectifier was outputting 34.1V and 10.2 A. The Line 1 Blackberry pumping station was inspected next. At the time of the inspection, the Line was idle, but there was a 15 psig differential between the suction and discharge pressures (S-206 psig, D-221 psig). A check valve in the station piping keeps the pressures from equalizing. Observed Steve Newton, station electrician, perform gas monitor calibrations for the VFD building and Unit 3.

After Blackberry, the team proceeded to MP 1035, where CP test stations had been missed as part of the annual CP survey. This location was in the middle of the Wawina swamp, and recent heavy rains had raised water levels to the point that CP readings were not practical. John Bissell had gone to the site following the records portion of the audit, however, and obtained CP readings.

The field inspection continued at the Floodwood pumping station, which pumps on Lines 2, 3 and 4, and concluded at the Gowan pumping station, which pumps on Line 1. The recap consisted of a review of items identified during the audit. Patsy Bolk expected to get a letter out on 10/1 which would address the items raised during the record portion of the audit. The recap included discussions of the importance of understanding how something was designed to function (N. Cass Lake CP system), so it's apparent when it's not functioning properly. Also discussed were the need to better manage information on exposed and shallow pipelines, which Mike Goman reported they had taken to heart following the records inspection. The only other items discussed were the issues associated with lack of atmospheric corrosion inspections and line markers at the Necktie River crossing.

10/9/07 BEP
Received a hard copy response to the issues identified during the records portion of the audit from Patsy Bolk, dated October 1, 2007. The detailed response addresses each item thoroughly. The following is a summary of the Enbridge response:

The 2005 and 2006 DOT Annual reports incorrectly reported the 20" Line 1 as transporting crude, when it was predominantly NGL, and these will be revised. The inaccuracy was attributed to mis-communication, and has been addressed by implementing a new information transfer process.

Procedures 2.0, 4.0, PI-03 step 4.3, and Section 8.0 from the Pipeline Integrity Excavation Program appear to adequately address the Safety Related Condition Reporting concern. These procedures weren't presented during the audit.

As stated during the audit, training records demonstrated compliance. Enbridge will review their practices to ensure and demonstrate compliance.

AOC's can be sorted on occurred date by requesting a modification of a view in the Notes database. The sorting issue is already thought to have been addressed in FACMAN, which is the current system for recording AOC's.

A revision request has been submitted for Book 7 (Emergency Response), Section 02-02-01, to clearly require consideration for notifying local officials in each and every situation.

The response provides a number of examples of AOC's from OQ Tasks, implying that operation of a safety device would be defined as an AOC in the Field, rather than the Control Center.That appears to be a stretch, but the response goes on to indicate Enbridge is reviewing this item with the understanding that the Control Center may have first notice, so they are developing procedures for each type of safety device and how the Control Center will react to them. As part of this, the Control Center is going to include all safety device activations as AOC's.

The Main Line Relief issue actually relates to two small thermal relief valves that serve the booster pump discharge lines. A historical documentation error prior to 2006 inadvertently omitted these two valves from the paper forms, and this issue carried into 2005. The practice was for personnel to check all manifold relief valves at the Terminal at the same time, and record the checks after they were all complete. This documentation issue was identified in 2006, and corrected going forward.

The response addressed the various corrosion control issues as follows:
MP 1035.483 - test point was missed - skipped by contractor because it's a "winter read", not picked up by the corrosion technician
MP 1043.064C - no need for additional test station
MP 1081.77 - reviewing the need for and feasibility of installing additional test stations.
MP 826 - Stephen Rectifier - Information was provided indicating the rectifier was checked and/or repaired at least once per month from September through December, of 2006.
MP 831.065 - does not exist. There are test stations at MP 830.800 and 831.724. The area is a farm field. There are readings for this milepost in 2004, but John Bissell believes they were recorded in error.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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.**

11-18-06

Inspection Report	**Post Inspection Memorandum**
Inspector/Submit Date: J.T. Williams 10-13-06	**Inspector/Submit Date:** J.T. Williams 11/15/06 **Peer Review/Date:** Charles P. Goetz 11/16/06 **Director Approval/Date:** 12/01/2006

POST INSPECTION MEMORANDUM (PIM)	
Name of Operator: Enbridge Energy	**OPID #:** 11169
Name of Unit(s): Lakehead - Tonawanda	**Unit # (s):** 1611
Records Location: Tonawanda, NY	
Unit Type & Commodity: Hazardous Liquid - Crude Oil	
Inspection Type: Standard Inspection	**Inspection Date(s):** October 10, 11, 2006
PHMSA Representative(s): Robert Smallcomb PHMSA, Al Saraceni, Jim Williams NYS DPS	**AFO Days:** 3 12

Summary:

We conducted a standard inspection of Enbridge's Unit #1611, Lakehead Pipeline. The unit consists of 20 miles of coated cathodically protected 12" steel pipeline and a pump station. The inspection included a records evaluation, field observations, and a Protocol 9 inspection. Our audit did include procedures since a team audit earlier this year was conducted. Terry Wasielewski was our NYS representative. We found all records were readily available and organized. We also obtained an IMP report to help enable us to schedule on site observations of an actual dig. Furthermore, we viewed the company's abnormal operating condtions database.

X-Team O&M conducted earlier in 2006 by PHMSA. No procedures reviewed.

Findings:

We found no instances of probable non-compliance nor did we identify any areas of concern.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

11-18-06

Name of Operator: **Enbridge Energy**	
OP ID No. [1]	**Unit ID No.** [1] **1611**
H.Q. Address:	**System/Unit Name & Address:** [1]
Enbridge Energy 1100 Louisiana Suite 3200 Houston, TX 77002	Chicago Region Line V-10 Two Mile Creek Road Tonawanda, NY 14150
Co. Official: Dan Tutcher	**Activity Record ID#:**
Phone No.: (713) 650-8900	**Phone No.:** (716) 692-0091
Fax No.: (713) 653-6711	**Fax No.:**
Emergency Phone No.: 800-858-5253	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Marc Curry	Senior Technician	716-692-0091 Ext 10
Jay Johnson	Compliance Coordinator	715-394-1512
Randy Roach	Project Coordinator	989-684-0160 Ext 16
Kimberly Harris	Corrosion Manager	219-775-7315

PHMSA Representative(s) [1] **A. Saraceni & J. Williams, PHMSA-Bob Smallcomb**	**Inspection Date(s)** [1] **Oct. 10,11,, 2006**
Company System Maps (copies for Region Files):	Copies on file in the Buffalo Office.

Unit Description:

Consists of approximately 20 miles of 12" coated protected steel pipe and one pump station. Our field evaluation verified a highly acceptable level of personnel knowledge.

Portion of Unit Inspected [1]

We evaluated OQ databases for company employees, contract welders, abnormal operating conditionsand incidents. We found no instances of probable non-compliance, nor areas of concern. We did not audit any procedures because they were covered in a team audit earlier this year. Terry Wasielewski is our NYS representative. We covered field and records.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and

[1] Information not required if included on page 1.

more restrictive new or amended regulations that became effective between 03/14/01 and 03/14/06.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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CONVERSION TO SERVICE		S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				x

Comments:

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
*	.49	Complete Annual Report and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Amdt 195-80 pub. 1/06/04, eff. 2/05/04.				x
* .402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)). Amdt 195-75 pub. 1/08/02, eff. 2/07/02				x
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				x
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				x
	.54(b)	Supplemental report - required within 30 days of information change/addition				x
	.55	Safety-related conditions (SRC) - criteria				x
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				x
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				x

Comments:

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				x

Comments:

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				x
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				x
		Welding procedures must be qualified by destructive testing.				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				x
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2001 Ed.)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 192-81 corr. Pub. 9/09/04.				x
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				x
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				x
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				x
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **§195.228(b)** and per the requirements of **§195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				x
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				x
		2. By qualified personnel				x
		3. By a process that will indicate any defects that may affect the integrity of the weld				x
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				x
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				x

Comments:

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions).				x
	.302(b)	Except for lines converted under **§195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				x
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				x
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				x

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SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				x
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				x
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				x
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with **§195.302**.				x
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				x
	.306	Appropriate test medium				x
	.308	Pipe associated with tie-ins must be pressure tested.				x
	.310(a)	Test records must be retained for useful life of the facility.				x
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				x
	.310(b)(2)	Test instrument calibration data.				x
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				x
	.310(b)(4)	Date and time of the test.				x
	.310(b)(5)	Minimum test pressure.				x
	.310(b)(6)	Test medium.				x
	.310(b)(7)	Description of the facility tested and the test apparatus.				x
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				x
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				x
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x

Comments:

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES				S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				x
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				x
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				x
	~~.402 (c)(5)~~	~~Analyzing pipeline accidents to determine their causes?~~				~~x~~
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				x
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				x
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?				x
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				x
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				x
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per §195.59.				x
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				x
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				x
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				x
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				x

Comments:

		ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				x
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				x
		iii. Loss of communications?				x

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
		iv. The operation of any safety device?				x
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				x
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				x
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				x
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				x
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				x

Comments:

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				x
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				x
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				x
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				x
	.402(e)(5)	Controlling the release of liquid at the failure site?				x
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				x
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				x
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				x
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				x

Comments:

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under §195.402.				x
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				x
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				x

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		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				x
*	**.403(a)(5)**	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				x
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				x
	~~**.403(b)(2)**~~	~~Make appropriate changes to the emergency response training program~~				~~x~~
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				x

Comments:

		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
.402(a)	**.402(c)(1)**	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				x
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				x
		ii. Pump stations				x
		iii. Scraper and sphere facilities				x
		iv. Pipeline valves				x
		v. Facilities to which **§195.402(c)(9)** applies				x
		vi. Rights-of-way				x
		vii. Safety devices to which **§195.428** applies				x
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				x
	.404(a)(3)	The maximum operating pressure of each pipeline.				x
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				x
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				x
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under **§195.402** apply.				x
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				x
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				x
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by **§195.106**.				x
	.406(a)(2)	The design pressure of any other component on the pipeline.				
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				x
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				x
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				x
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				x
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				x

Comments:

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				x
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **§195.402(c)(9)**.				x
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				x
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				x
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				x

Comments:

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				x
	.410(a)(2)	Must have the correct characteristics and information				x
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

INSPECTION RIGHTS-of-WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				x
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**.				x

Comments:

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				x
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				x

Comments:

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				x
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year.				x
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				x

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Comments:

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PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
~~.402(a)~~	~~.422(a)~~	~~Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner~~ and are made so as to prevent damage to persons and property.				x
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				x

Comments:

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				x
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				x
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.				x
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				x
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				x
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.				x
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				x

Comments:

SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				x
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				x
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				x
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.				x
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				x
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				x
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				x

Comments:

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				x
		The equipment must be:				
		a. In proper operating condition at all times.				x
		b. Plainly marked so that its identity as firefighting equipment is clear.				x
		c. Located so that it is easily accessible during a fire.				x

Comments:

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				x

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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **§195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years				x
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.**				x
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				x
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:

		SIGN PROCEDURES	S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				x
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x

Comments:

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				x

Comments:

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PUBLIC EDUCATION PROCEDURES			S	U	N/A	N/C
.402(a) *	.440	Establishing a continuing educational program (in English and other pertinent languages) to better inform the public in how to recognize and report potential hazardous liquid or carbon dioxide pipeline emergencies [prior to June 20, 2006]				x
		Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				

Comments:

DAMAGE PREVENTION PROGRAM PROCEDURES			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				x
	.442(b)	Does the operator participate in a qualified One-Call program?				x
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				x
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				x
		ii. How to learn the location of underground pipelines before excavation activities are begun.				x
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				x
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				x
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				x
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				x
		ii. In the case of blasting, any inspection must include leakage surveys.				x

Comments:

CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				x

Comments:

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Comments:

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

*	SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)		S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				x
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				x
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				x
		2) Is a segment that is relocated, replaced, or substantially altered?				x
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				x
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				x
		b. All coating damage discovered must be repaired.				x
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**?				x
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				x
		2) Is a segment that is relocated, replaced, or substantially altered?				x
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				x
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				x
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				x

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
	.567	Test leads installation and maintenance.				x
	.569	Examination of Exposed Portions of Buried Pipelines.				x
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-96** (incorporated by reference).				x
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**.				x
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.				x
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-96.**				x
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				x
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months**				x
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**				x
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				x
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				x
	.575	Are there adequate provisions for electrical isolations?				x
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				x
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				x
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				x
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**				x
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				x
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				x
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				x
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months**				x
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				x

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				x
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?**				x
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				x

Comments:

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.262	Pumping Stations	1A			
.262	Station Safety Devices	2A			
.308	Pre-pressure Testing Pipe - Marking and Inventory			3A	
.403	Supervisor Knowledge of Emergency Response Procedures				4A
.410	Right-of-Way Markers	5A			
.412	ROW/Crossing Under Navigable Waters				6A
.420	Valve Maintenance				7A
.420	Valve Protection from Unauthorized Operation and Vandalism	8A			
.426	Scraper and Sphere Facilities and Launchers	9A			
.428	Pressure Limiting Devices				10A
.428	Relief Valves - Location - Pressure Settings - Maintenance				10A
.428	Pressure Controllers				10A
.430	Fire Fighting Equipment	11A			
.432	Breakout Tanks			12A	
.434	Signs - Pumping Stations - Breakout Tanks	13A			
.436	Security - Pumping Stations - Breakout Tanks	14A			
.438	No Smoking Signs	15A			
.501-.509	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	16A			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	17A			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	18A			
.575	Electrical Isolation; shorted casings	19A			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)	20A			

PART 195 - RECORDS REVIEW	S	U	N/A	N/C
CONVERSION TO SERVICE				

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.	23B			
.5(c)	Pipeline Records (Life of System)	23B			
	Pipeline Investigations	23B			
	Pipeline Testing	23B			
	Pipeline Repairs	23B			
	Pipeline Replacements	23B			
	Pipeline Alterations	23B			
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	24B			
.52	Telephonic Reports to NRC (800-424-8802)	25B			
.54(a)	Written Accident Reports (DOT Form 7000-1)	25B			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	25B			
.56	Safety Related Conditions	25B			
.57	Offshore Pipeline Condition Reports	26B			
.59	Abandoned Underwater Facility Reports	26B			
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	27B			
.214(b)	Test Results to Qualify Welding Procedures	27B			
.222	Welder Qualification	27B			
.234(b)	Nondestructive Technician Qualification	27B			
.589	Cathodic Protection	27B			
.266	Construction Records	27B			
.266(a)	Total Number of Girth Welds	27B			
	Number of Welds Inspected by NDT	27B			
	Number of Welds Rejected	27B			
	Disposition of each Weld Rejected	27B			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	27B			
.266(c)	Location of each Crossing with another Pipeline	27B			
.266(d)	Location of each buried Utility Crossing	27B			
.266(e)	Location of Overhead Crossings	27B			
.266(f)	Location of each Valve and Test Station	27B			
	PRESSURE TESTING				
.310	Pipeline Test Record	28B			
.305(b)	Manufacturer Testing of Components	29B			
.308	Records of Pre-tested Pipe	30B			
	OPERATION & MAINTENANCE				

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	1			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	2			
.402(c)(10)	Abandonment of Facilities	3			
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	4			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	5			
.402(d)(1)	Response to Abnormal Pipeline Operations	6			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	6			
.402(e)(1)	Notices which require immediate response	7			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	8			
.402(e)(9)	Post Accident Reviews	9			
.403(a)	Emergency Response Personnel Training Program	10			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	11			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	12			
.404(a)(1)	Maps or Records of Pipeline System	13			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	13			
.404(a)(3)	MOP of each Pipeline	14			
.404(a)(4)	Pipeline Specifications	13			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	15			
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs)	16			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	17			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	18			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	19			
.406(a)	Establishing the MOP	20			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	21			
.412(a)	Inspection of the ROW	22			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	23			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk	23A			
.420(b)	Inspection of Mainline Valves	24			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)	25			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			25	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)			25	
.430	Inspection of Fire Fighting Equipment	26			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).			25	
.440	Public Education/Awareness Program	27			
DAMAGE PREVENTION PROGRAM					
.442(c)(1)	List of Current Excavators	28			
.442(c)(2)	Notification of Public/Excavators	28			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	28			
CORROSION CONTROL					
.555	Supervisors maintain thorough knowledge of corrosion procedures.	29			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	30			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	31			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests **(1 per yr/15 months)**	32			
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	33			
~~**.589(c)/.573(b)**~~	~~External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas **(1 per 3**~~ **cal yr/39 months)**	34			
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	35			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks			25	
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	36			
.589(c)/.575	Electrical isolation inspection and testing	37			
.589(c)/.577	Testing for Interference Currents	38			
.589(c)/.579(a)	Corrosive effect investigation	39			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment **(2 per yr/7½ months)**	40			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	41			
.589(c)/.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**	42			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	43			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	43			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	44			

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	45		
194.111	RSPA Tracking Number: **868** Approval Date: **10/25/99**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	46		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	47		
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	48		
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]	48		

Comments *(If any of the above is marked N or N/A, please indicate why, either in this box or in a referenced note):*

OPA Inspection Guidance

<u>OPA-1</u> - **RSPA Tracking Number**: This is also known as the "sequence number." It is a four-digit number that PHMSA HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, PHMSA HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by PHMSA. The operator should be able to produce their PHMSA plan approval letter. When PHMSA HQ approves a plan, the approval is valid for five years from the date of the approval letter.

<u>OPA-2</u> - **Names and phone numbers**: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

<u>OPA-3</u> - **Proof of OSRO contract**: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSROs) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

<u>OPA-4</u> - **Exercise documentation**: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to PHMSA for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that PHMSA HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

<u>OPA-5</u> - **Training records**: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Recent PHMSA Advisory Bulletins (Last 2 years)

Leave this list with the operator.

Number	Date	Subject
ADB-04-02	July 22, 2004	Pipeline Safety: Semi-Annual Reporting of Performance Measures for Gas Transmission Pipeline Integrity Management
ADB-04-03	August 18, 2004	Pipeline Safety: Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities
ADB-04-04	September 23, 2004	Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Ivan
ADB-04-05	November 26, 2004	Pipeline Safety: Operator Qualification Requirements
ADB-05-01	January 21, 2005	Pipeline Safety: Semi-Annual Reporting of Performance Measures for Gas Transmission Pipeline Integrity Management
ADB-05-02	April 6, 2005	Pipeline Safety: Strapping Table Calibration for Pipeline Breakout Tank Operators
ADB-05-03	May 23, 2005	Pipeline Safety: Planning for Coordination of Emergency Response to Pipeline Emergencies
ADB-05-04	July 29, 2005	Integrity Management Notifications for Gas Transmission Lines
ADB-05-05	August 10, 2005	Pipeline Safety Advisory Bulletin - Inspecting and Testing Pilot-Operated Pressure Relief Valves
ADB-05-06	August 11, 2005	ADB-05-06 - Pipeline Safety - Countermeasures to Prevent Human Fatigue in the Control Room
ADB-05-07	September 7, 2005	Pipeline Safety Advisory - Potential for damage to Natural Gas Distribution Pipeline Facilities Caused by the Passage of Hurricane Katrina
ADB-05-08	September 7, 2005	Pipeline Safety Advisory - Potential for damage to Pipeline Facilities Caused by the Passage of Hurricane Katrina
ADB-06-01	January 17, 2006	Pipeline Safety: Notice to Operators of Natural Gas and Hazardous Liquid Pipelines To Integrate Operator Qualification Regulations into Excavation Activities

For more PHMSA Advisory Bulletins, go to http://ops.dot.gov/regs/advise.htm

Field Notes:

1. We evaluated annual reviews for 2004-2006. All manuals contained a log showing dates reviewed.

2. All areas get immediate responses and are treated equally.

3. Enbridge has no abandoned lines under navigatable waterways.

4. Enbridge sponsors Safety Com solutions' presentations for excavators and public officials. The last presentation was 5/10/06. Also, Paradigm mails awareness literature to excavator, public officials, and the land owners.

5. All normal operating conditions are logged and to clear it a Maximo tracking number is assigned which the employee's supervisor must sign off on.

6. All AOC's are logged and assigned a Maximo tracking number. Reports are checked and cleared by a supervisor.

7. Line 10 has not had an incident requiring immediate response.

8. There has been no need to notify fire, police, and other public officials of an emergency.

9. There have been no accidents on Line 10.

10. Maintained by regional safety training coordinator. I observed several records for Neil Cooney.

11. Line 10/Enbridge has three emergency based manuals. I observed the modification log and the manual have been updated every 15 months.

12. I observed qualifications in a database detailing supervisor knowledge of Emergency Response Procedures.

13. I observed alignment sheets, flow diagrams, and site safety plot plans.

14. I obtained copies of MOP records and found no problems.

15. Pump station daily suction, case, and discharge pressure records are stored on Yogagowa digital chart records.

16. I observed records back to 2004 in the AOC database.

17. Pipeline maintenance system maintains all repairs to the pipe.

18. We observed one record from May 14, 2003. The SCADA system shut down pump unit # because of a deficient outer bearing.

19. All inspection and test records are maintained for at least two years.

20. Line 10 lowered its line pressure.

21. AOC database is the filing place.

22. We reviewed ROW inspections for 2006 and we found no areas of concern.

23. We reviewed the findings of the 2003 inspections of the Niagara and Buffalo river crossings and we found no areas of concern.

24. I observed records from 2004-2006 and all value inspections were compliant.

25. I observed record for 10/25/05 and 9/28/04 the test pressure was 490 PSIG. The unit has no tanks.

26. All fire fighting equipment was marked, maintained, and accessible.

27. The Public Awareness Programs were audited earlier this year and no areas of concern were identified.

28. Line 10 is a member of the local one-call system.

29. I obtained copies of Kimberly Harris' Corrosion Supervisor, qualifications detailing her knowledge of corrosion procedures.

30. I examined the test lead report for 2005 and found it compliant.

31. Exposed pipe inspection reports are in the PLM Activity System. I observed records in the system and they were compliant.

32. I reviewed the year survey and found that deficiencies are noted and are compliant.

33. A close interval is scheduled for 2007. No records for past surveys were available.

34. Line 10 has no unprotected pipe.

35. I examined rectifier inspection records for 1/16/04 to 5/7/06 and found no problem.

36. I observed the criteria in Book 3, Table I, obtained a spread detailing corrective actions required by IMP.

37. I observed records for pipe and casing readings. Four shorts were identified and two have been repaired at this time.

38. No interference currents have been identified.

39. Line 10 used in-line inspection tools and I obtained a spread sheet detailing the anomalies.

40. We obtained all off the records for the foil on Grand Island, these were acceptable.

41. No pipe has been removed.

42. I observed records for the 2005 O&M corrosion study. Funds will be allocated in 2007 to repair areas that were identified.

43. There has been in non-IMP areas. IMP rules are stricter.

44. On alignment sheets and annual survey binder.

45. Enbridge's system for the plan is found in book #7.

46. The names and numbers in the FRP are current.

47. I observed copies of the written contract for spill control.

48. I observed a copy of a drill held on 6/14/06 for Line 10.

Field Review

1A. The pump station building is adequately ventilated and equipped with hazardous vapor warning devices. The facility is fenced and is greater than 50 feet from the boundaries of the station. The station was also equipped with numerous dry chemical fire extinguishers.

2A. The pumps are equipped with over pressuring safety devices that are constantly monitored, a high-level sump tank alarm, and there are emergency shut down switches.

3A. There is not pre-tested pipe stored at this unit.

4A. We observed no Emergency Response Training because none was scheduled during our audit.

5A. We observed right-of-way line markers at the following locations and they were compliant.
West River Road, Grand Island
Baseline Road, Grand Island
East River Road, Grand Island
I-190
River Road, Tonawanda
Mineral Springs Road, West Seneca
Clint Street-Buffalo
Millersport Highway
Tonawanda Pump Station
Tonawanda channel of Niagara River
Chippewa Channel of Niagara River

6A. There was no inspection scheduled for crossings under a navigable waterway.

7A. We observed no value maintenance. None was scheduled during our visit.

8A. we found that valves were protected from unauthorized operation and vandalism. We made field observations at the following locations:
-Chippewa Channel Launcher
-Tonawanda Channel Receiver
-Williamsville Station
-Clinton Street
-Mineral springs Road/Receiver

9A. We observed that scraper and sphere facilities had pressure gauges, pressure relief valves, and pressure relief piping at the following locations.
-Chippewa Channel Launcher Facility
-Tonawanda Channel Receiver Facility
-Mineral Springs Road Receiver Facility

10A. We observed no pressure limiting device, relief valve, or pressure controller testing because none was scheduled during our visit.

11A. We observed a 150 lb and three 35 lb dry chemical (Purple K) fire extinguishers in and near the pump station.

12A. The unit has no break-out tanks.

13A. We observed signs around the pump station, visible to the public, displaying the name and telephone of the operator.

14A. The Tonawanda Pump Station facility is fenced in.

15A. We observed no smoking signs at the Tonawanda Pump Station.

16A. We reviewed Operator Qualifications and we documented our observations on a Form 15 Protocol Field Report.

17A. We observed pipe-to-soil readings at the following locations and found them compliant:

Chippewa Channel	-1.586mv	
Tonawanda Channel	-1.925mv	
Staley Road	-1.560mv casing	.737 mv
Millersport Road	-1.795mv	
Clinton	-1.921mv	

18A. We examined readings on rectifiers at the following locations and we found them to be operating well within their design range.

-Tonawanda Channel
-Millersport Road
-Clinton Street

We examined readings of bonds at the following locations and we found they were compliant:
-Chippewa Channel
-River Road-Tonawanda
-Mineral Springs Road

19A. Enbridge demonstrated electrical isolation on Staley Road as follows:

Pipe-to-Soil	-1.560 mv
Casing	- .737 mv

20A. Enbridge took a survey in 2005 and deficiencies identified by their investigation will be corrected in 2007. We plan to follow up on their corrective action during the 2007 audit year.

23B. Lakehead had been used to carry crude oil since its construction.

24B. We obtained and reviewed Enbridge's 2006 report.

25B. Nothing has been reported since May 14, 2003.

26B. Lakehead has no offshore or abandoned underwater facilities.

27B. There has been no construction activities on the line since the Tonawanda Pump Station was built several years ago (1997).

28B. We reviewed the original pressure test records for the pipeline and we found no areas of concern.

29B. We did not review any records of manufacturer's testing of components because there was no construction on the pipeline.

30B. There was no pre-tested pipe at this location.

OPERATOR QUALIFICATION
FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	October 10, 11, 2006
Name of Operator:	Enbridge/Lakehead Pipeline
Inspection Location(s):	Tonawanda, Grand Island
Supervisor(s) Contacted:	Marc Carry
# Qualified Employees Observed:	1
# Qualified Contractors Observed:	2

Individual Observed	Title/Organization	Phone Number	Email Address
David Hill	Roberts P/L Construction		
Nicholas Deaton	Roberts P/L Construction		
Kimberly Harris	Enbridge PIpeline		

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Al Saraceni	Eastern NY	Alfred_Saraceni@dps.state.ny.us
Jim Williams	Eastern NY	James_Williams@dps.state.ny.us

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is available for convenience as the last page of this form. Other formats can also be used. Only the Inspection Results are imported into the database.

9.01 Covered Task Performance

Have the qualified individuals performed the observed covered tasks in accordance with the operator's or contractor's approved procedures, qualification evaluation process, and/or the manufacturer's instructions?

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The employee or contractor individual(s) should be observed performing two separate covered tasks, with only one of the covered tasks being performed as a shop simulation. Obtain a copy of the procedure(s) used to perform the task(s). The individuals should be able to describe key items to be considered for correct performance of the task, and demonstrate strict compliance with procedure requirements. If a crew performing a job is observed (such as installing a service line, tapping a main and supplying gas to a meter set), the individual covered tasks should be identified and documented and the crew member performing the task(s) should be questioned as above.

Additional considerations for covered task observations:

1. Determine if procedures prepared by the operator to conduct the task(s) are present in the field and are being used as necessary to perform the task(s).
2. Confirm that the procedures being used in the field are the same (content, revision number, and/or date issued) as the latest approved procedures in the operator's O&M manual.
3. Confirm that the procedures employed by contractor individuals performing covered tasks are those approved by the operator for the tasks being performed.
4. Ensure that procedure adherence is accomplished and that "work-arounds"[1] are not employed that would invalidate the evaluation and qualification that was performed for the individual in performance of the task.
5. Determine if all of the tools and special equipment identified in procedures are present at the job site and are properly employed in the performance of the task, and if techniques and special processes specified are used as described.

9.02 Qualification Status

[1] A "work-around" is a situation where the individual is using a procedure that wouldn't work the way it was written (due to an inadequate procedure or an equipment change that made the procedure steps invalid), or the individual has found a "better" way to get the job done faster instead of using the tool the way it was designed (e.g., not making depth measurements on a tapping tool because you had never drilled through the bottom of the pipe), or not taking the time to follow the manufacturer's instructions (not marking the stab depth when using a Continental coupling to join two sections of plastic pipe) because he never experienced a problem.

Are the individuals performing covered tasks currently qualified to perform the tasks?

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The name of each individual observed should be noted and a subsequent review of their qualification records performed to ensure that: 1) the individual was qualified to perform the task observed; and 2) the individual's qualifications are current. A review of the evaluation requirements contained in the operator's or contractor's OQ written program should be performed to ensure that all requirements were met for the current qualification. In addition, a review of the evaluation instruments (written tests, performance evaluation checklists, etc.) may be performed to determine if any of these contain deficiencies (e.g., too few questions to ensure task knowledge, failure to address critical task requirements). Reviews of qualification records and/or evaluation instruments should ensure that AOC evaluation has been performed.

9.03 Abnormal Operating Condition Recognition and Reaction

Are the individuals performing covered tasks cognizant of the AOCs that are applicable to the tasks observed?

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: This inspection should focus on an individual's knowledge of the AOCs applicable to the covered task being performed and the ability to recognize and react to those AOCs. The information gained during the inspection should be compared to the requirements for qualification applied by the operator or contractor during the evaluation process for the subject covered task (e.g., knowledge of task-specific AOCs in addition to generic AOCs). If contractor individuals are observed, confirm whether the AOCs identified in the operator's written program are the ones used for qualification of the contractor individual.

9.04 Verification of Qualification

Are qualification records verified at the job site to be current, and is personal identification of contractor individuals performing covered tasks checked, prior to task performance?

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: Supervisors, crew foremen or other persons in charge of field work must be able to verify that the qualifications of individuals performing covered tasks. This typically applies to individuals employed by the operator that are from another district or field office, where the qualification status may be unknown or uncertain, or to contractor individuals. Employee records should be made available through company databases or other means of verification, while contractors should be required to provide documentation of qualification prior to beginning work, and also provide a form of identification that is satisfactory to correlate the qualification documentation with the individual performing the task.

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: If the field inspection is performed subsequent to the headquarters inspection (six months or more), the OQ database or inspection records should be checked to determine if any potential issues that were identified as having implications for incorrect task performance (e.g., no skills evaluation for tasks requiring knowledge and skills; hands-on evaluations were performed as a group as opposed to individually; span of control was not specified on a task-specific basis; evaluation and qualification on changed tasks or changed procedures not performed; inadequate provisions for, or inadequate implementation of requirements for, suspension of qualification following involvement in an incident or for reasonable cause) have been corrected.

Field Inspection Notes

The following table is provided for *convenience* in recording the tasks observed and the individuals performing those tasks. Other formats, and even separate files, may also be used. This information is *not* imported into the OQ database.

No	Task Name	Name/ID of Individual Observed						Comments
		David Hill		Nicholas Deaton		Kimberly Harris		
		Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	
1	Pipe to soil readings	N	N	N	Y	Y	Y	
2	Rectifier Readings	N	N	N	Y	Y	Y	
3	Bond readings	N	N	N	Y	Y	Y	
4	Check external corrosion	N	Y	N	Y	N	Y	
5	Line Location	N	Y	N	Y	N	N	
6	Maintain Line Markers	N	Y	N	Y	N	N	
7								
8								

Example table use (can be deleted):

No	Task Name	Name/ID of Individual Observed						Comments
		Bill Smith		Mary Jones		Clint Nelson		
		Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	
1	Cathodic Reading	Y	Y					
2	Critical Valve Operation			Y	Y	Y	N	Clint Nelson lacked required training.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: Enbridge (US), Inc.	
OP ID No. [1] **11169**	**Unit ID No.** [1] **1343, 2953, 12823**
H.Q. Address:	**System/Unit Name & Address:** [1]
1100 Louisiana St. Suite 3300 Houston, TX 77002	1343 - Fort Atkinson 2953 - Bay City 12823 - Griffith
Co. Official: Mr. Terry McGill	**Activity Record ID#:** 117279, 117280, 117281
Phone No.: 713-650-8900	**Phone No.:**
Fax No.: 713-653-6711	**Fax No.:**
Emergency Phone No.: 800-858-5253	**Emergency Phone No.:** Same

Persons Interviewed	Titles	Phone No.
Jay Johnson	Compliance	
Vince Kolbruck	Engineer	
Kim Davis	Corrosion Engineer	

PHMSA Representative(s) [1] **David Barrett** **Inspection Date(s)** [1] **See Below in Portion inspected**

Company System Maps (copies for Region Files): Yes

Unit Description:

1343 Ft. Atkinson -- 34" Line 6A from Superior to MP 386 (Dundee, IL). 24" Line 14 from Superior to Burlington, IL Station.

2953 Bay City -- 30" Line 5 from Lewiston Sta. to Canadian Border near Marysville, MI.
30" Line 6B from New Carlisle, IN to Canadian Border near Sarnia

12823 Griffith -- 34" Line 6A from Dundee, IL to Griffith. 30" Line 6B from Griffith to New Carlisle, IN. 24" Line 14 from Mokena, IL to Burlington Station.

Portion of Unit Inspected [1]

All 3 Units were inspected. O&M records were reviewed, and the R/W inspected with stops at various pump stations and facilities. P/S readings were taken with no deficiencies noted. A team O&M inspection was completed the week of May 9, 2006 and was led by SW Region.

Unit 1343 -- Ft. Atkinson -- 9 AFODs from 9/18 to 11/9/2006
Unit 2953 -- Bay City -- 9 AFODs from 10/16 to 11/3/2006
Unit 18253 -- Griffith --- 5 AFODs week of 10/23/2006.

FINDINGS: A thermal relief valve was present at station, and at time of inspection the TRV was isolated. Upon further review of P&ID it was demonstrated that TRV was not necessary due to operation of station. Final disposition of the TRV for DOT record checks was resolved.

A non-standard was used in a pressure transmitter cabinet to cap lines, but was changed to a bushing per Enbridge standards.

In the Chicago Region it was unclear if insulator kits on flanges at pipeline interconnects were checked, but upon further review insulators were checked. Improved documentation was recommended.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Periodic training for emergency response was completed as scheduled. However, documentation could be clearer to show that Action Items are implemented.

Marginally cleared R/W was noted, but all clearing was scheduled following the harvest season.

Not all districts were using the latest Enbridge form to determine root cause, but a notice was issued by the districts to assure use of the new form prior to the end of inpection visit.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during PHMSA inspections. Refer to the Hub Joint O&M team inspection schedule to identify inter-regional operators. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/14/01 and 03/14/06.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	CONVERSION TO SERVICE	S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				x

Comments:
See O&M inspection.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
*	.49	Complete Annual Report and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Amdt 195-80 pub. 1/06/04, eff. 2/05/04.				x
* .402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)). Amdt 195-75 pub. 1/08/02, eff. 2/07/02				x
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				x
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				x
	.54(b)	Supplemental report - required within 30 days of information change/addition				x
	.55	Safety-related conditions (SRC) - criteria				-x
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				x
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				x

Comments:
Team O&M in May 2006.

		SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				x

Comments:
Team O&M in May 2006.

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
*	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				x
.402(c)/ .422		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				x
		Welding procedures must be qualified by destructive testing.				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				x
*	**.222(a)**	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2001 Ed.)**, except that a welder qualified under an earlier edition than listed in **' 195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 192-81 corr. Pub. 9/09/04.				x
*	**.222(b)**	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	**.226(a)**	Arc burns must be repaired.				x
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				x
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				x
	Nondestructive Testing Procedures					
*	**.228 /.234**	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **' 195.228(b)** and per the requirements of **' 195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				x
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				x
		2. By qualified personnel				x
		3. By a process that will indicate any defects that may affect the integrity of the weld				x
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				x
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 9 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				x

Comments:
Team O&M in May 2006.

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	**.302(a)**	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions).				x
	.302(b)	Except for lines converted under **' 195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				x
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in ' 195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				x
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				x
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				x
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				x
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with ' 195.302.				x
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				x
	.306	Appropriate test medium				x
	.308	Pipe associated with tie-ins must be pressure tested.				x
	.310(a)	Test records must be retained for useful life of the facility.				x
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				x
	.310(b)(2)	Test instrument calibration data.				x
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				x
	.310(b)(4)	Date and time of the test.				x
	.310(b)(5)	Minimum test pressure.				x
	.310(b)(6)	Test medium.				x
	.310(b)(7)	Description of the facility tested and the test apparatus.				x
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				x
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				x
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x

Comments:
Team O&M in May 2006.

			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				x
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				x
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Team O&M in May 2006.

		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
.402(a)	**.402(c)**	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				x
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				x
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				x
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **' 195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				x
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **' 195.406**?				x
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **' 195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				x
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				x
		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59.				x
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section, where the potential exists for the presence of flammable liquids or gases?				x
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				x
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				x
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				x

Comments:
Team O&M in May 2006.

		ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C
.402(a)	**.402(d)**	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				x
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				x
		iii. Loss of communications?				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
		iv. The operation of any safety device?				x
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				x
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				x
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				x
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				x
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				x

Comments:
Team O&M in May 2006.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				x
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				x
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				x
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				x
	.402(e)(5)	Controlling the release of liquid at the failure site?				x
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				x
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				x
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				x
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				x

Comments:
Team O&M in May 2006.

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				x
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				x
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				x
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				x
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				x
	.403(b)(2)	Make appropriate changes to the emergency response training program				x
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				x

Comments:
Team O&M in May 2006.

		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				x
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				x
		ii. Pump stations				x
		iii. Scraper and sphere facilities				x
		iv. Pipeline valves				x
		v. Facilities to which ' **195.402(c)(9)** applies				x
		vi. Rights-of-way				x
		vii. Safety devices to which ' **195.428** applies				x
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				x
	.404(a)(3)	The maximum operating pressure of each pipeline.				x
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				x
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				x
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under ' **195.402** apply.				x
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				x
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				x
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Team O&M in May 2006.

MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by ' **195.106**.				x
	.406(a)(2)	The design pressure of any other component on the pipeline.				x
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				x
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				x
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				x
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				x
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				x

Comments:
Team O&M in May 2006.

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				x
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by ' **195.402(c)(9)**.				x
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				x
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				x
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				x

Comments:
Team O&M in May 2006.

LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				x
	.410(a)(2)	Must have the correct characteristics and information				x
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Team O&M in May 2006.

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				x
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 **years**.				x

Comments:
Team O&M in May 2006.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				x
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				x
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				x

Comments:
Team O&M in May 2006.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.				x
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding 72 **months**, but at least **twice** each calendar year.				x
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:

		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				x
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				x

Comments:
Team O&M in May 2006.

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				x
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				x
	.424(b)(2)	Have procedures under **' 195.402** containing precautions to protect the public.				x
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				x
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				x
	.424(c)(2)	Have procedures under **' 195.402** containing precautions to protect the public.				x
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				x

Comments:
Team O&M in May 2006.

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				x
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Team O&M in May 2006.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				x
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				x
		2. **HVL** pipelines at intervals not to exceed 72 **months**, but at least **twice** each calendar year.				x
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				x
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				x
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				x

Comments:
Team O&M in May 2006.

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				x
		The equipment must be:				
		a. In proper operating condition at all times.				x
		b. Plainly marked so that its identity as firefighting equipment is clear.				x
		c. Located so that it is easily accessible during a fire.				x

Comments:

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
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		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 6 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under ' **195.402(c)(3)**. -Owner/operator visual, external condition inspection interval n.t.e. one month. (more frequent inspections may be needed based on conditions at particular sites) -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				x
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.**				x
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				x
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
Team O&M in May 2006.

		SIGN PROCEDURES	S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				x
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				x

Comments:

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				x

Comments:
Team O&M in May 2006.

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				x

Comments:
Team O&M in May 2006.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PUBLIC EDUCATION PROCEDURES			S	U	N/A	N/C
.402(a) *	.440	Establishing a continuing educational program (in English and other pertinent languages) to better inform the public in how to recognize and report potential hazardous liquid or carbon dioxide pipeline emergencies [prior to June 20, 2006]				x
		Public Awareness Program in accordance with API RP 1162 [HQ clearinghouse review after June 20, 2006] Amdt 195-83 pub. 5/19/05, eff. 06/20/05.				

Comments:
Team O&M in May 2006.

DAMAGE PREVENTION PROGRAM PROCEDURES			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				x
	.442(b)	Does the operator participate in a qualified One-Call program?				x
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				x
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				x
		ii. How to learn the location of underground pipelines before excavation activities are begun.				x
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				x
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				x
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				x
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				x
		ii. In the case of blasting, any inspection must include leakage surveys.				x

Comments:
Team O&M in May 2006.

CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				x

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Team O&M in May 2006.

	PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES	**S**	**U**	**N/A**	**N/C**
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

	SUBPART G - OPERATOR QUALIFICATION PROCEDURES	**S**	**U**	**N/A**	**N/C**
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

*		**SUBPART H - CORROSION CONTROL PROCEDURES** (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	**S**	**U**	**N/A**	**N/C**
.402(a)	**.555**	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance?				x
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				x
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				x
		2) Is a segment that is relocated, replaced, or substantially altered?				x
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				x
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				x
		b. All coating damage discovered must be repaired.				x
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**?				x
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				x
		2) Is a segment that is relocated, replaced, or substantially altered?				x
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				x
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				x
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
	.567	Test leads installation and maintenance.				x
	.569	Examination of Exposed Portions of Buried Pipelines.				x
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-96** (incorporated by reference).				x
	.573	a. (1) Pipe to soil monitoring **(annually / 15months).**				x
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months).**				x
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-96.**				x
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				x
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				x
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 22 mos.**				x
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				x
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b).**				x
	.575	Are there adequate provisions for electrical isolations?				x
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				x
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				x
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				x
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 2 months.**				x
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				x
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				x
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				x
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				x
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	X			
.52	Telephonic Reports to NRC (800-424-8802)	X			
.54(a)	Written Accident Reports (DOT Form 7000-1)	X			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	X			
.56	Safety Related Conditions	X			
.57	Offshore Pipeline Condition Reports	X			
.59	Abandoned Underwater Facility Reports	X			
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification				
.214(b)	Test Results to Qualify Welding Procedures				
.222	Welder Qualification				
.234(b)	Nondestructive Technician Qualification				
.589	Cathodic Protection				
.266	Construction Records				
.266(a)	Total Number of Girth Welds				
	Number of Welds Inspected by NDT				
	Number of Welds Rejected				
	Disposition of each Weld Rejected				
.266(b)	Amount, Location, Cover of each Size of Pipe Installed				
.266(c)	Location of each Crossing with another Pipeline				
.266(d)	Location of each buried Utility Crossing				
.266(e)	Location of Overhead Crossings				
.266(f)	Location of each Valve and Test Station				
	PRESSURE TESTING				
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			
.308	Records of Pre-tested Pipe	X			
	OPERATION & MAINTENANCE				

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities	X			
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	X			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			X	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	X			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			
.440	Public Education/Awareness Program	X			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
	CORROSION CONTROL				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)	X			
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)			X	
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	X			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (**2 per yr/7½ months**)	X			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)	X			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:

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.** Refer to the last page of this form for **PIM** example entries.

11/1/06

Inspection Report		Post Inspection Memorandum	
Inspector/Submit Date:	J. Williams 5/5/06	**Inspector/Submit Date:**	J. Williams 5/5/06
		Peer Review/Date:	Charles P. Goetz 5/5/06
		Director Approval/Date:	11/15/06

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Pipeline Co.	**OPID #:**	11169
Name of Unit(s):	Lakehead	**Unit #(s):**	1611
Records Location:	Tonawanda, NY		
Unit Type & Commodity:	12" rectified, coated, steel pipe – Crude Oil		
Inspection Type:	Specialized	**Inspection Date(s):**	4/13/06
PHMSA Representative(s):	James T. Williams	**AFO Days:**	1

Summary:

An internal inspection tool detected an anomalie in Enbridge's pipeline off Park Club Lane in the Town of Amherst. The company used the one call notification system, they excavated under ticket #03316-140-014-00, and they were compliant with 16 NYCRR Part 753, Damage Prevention. The map the crew had at the site was current, dated 2/3/04. They found a 36" concrete water main on top of their pipeline and they temporarily stopped excavation pending guidance from their Engineering Dept. I checked operator qualifications for Ronald Skrocki, Michael McCamey, and Dennis Maillette and found they were compliant. The crew complied with company procedures for the work associated with this project and copies of their procedures for trenching and excavation, Book 3, Section 4 and for Pipe Repair and Modification, Book 3, Section 6, were available on site.

Findings:

I found that Enbridge's personnel were qualified and knowledgeable about their tasks. There were no instances of probable non-compliance found during my inspection.

OPERATOR QUALIFICATION FIELD INSPECTION PROTOCOL FORM

QFS. 11/1/06

Inspection Date(s):	October 10, 11, 2006
Name of Operator:	Enbridge/Lakehead Pipeline
Inspection Location(s):	Tonawanda, Grand Island
Supervisor(s) Contacted:	Marc Carry
# Qualified Employees Observed:	1
# Qualified Contractors Observed:	2

Individual Observed	Title/Organization	Phone Number	Email Address
David Hill	Roberts P/L Construction		
Nicholas Deaton	Roberts P/L Construction		
Kimberly Harris	Enbridge PIpeline		

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Al Saraceni	Eastern NY	Alfred_Saraceni@dps.state.ny.us
Jim Williams	Eastern NY	James_Williams@dps.state.ny.us

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is available for convenience as the last page of this form. Other formats can also be used. Only the Inspection Results are imported into the database.

9.01 Covered Task Performance

Have the qualified individuals performed the observed covered tasks in accordance with the operator's or contractor's approved procedures, qualification evaluation process, and/or the manufacturer's instructions?

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The employee or contractor individual(s) should be observed performing two separate covered tasks, with only one of the covered tasks being performed as a shop simulation. Obtain a copy of the procedure(s) used to perform the task(s). The individuals should be able to describe key items to be considered for correct performance of the task, and demonstrate strict compliance with procedure requirements. If a crew performing a job is observed (such as installing a service line, tapping a main and supplying gas to a meter set), the individual covered tasks should be identified and documented and the crew member performing the task(s) should be questioned as above.

Additional considerations for covered task observations:

1. Determine if procedures prepared by the operator to conduct the task(s) are present in the field and are being used as necessary to perform the task(s).
2. Confirm that the procedures being used in the field are the same (content, revision number, and/or date issued) as the latest approved procedures in the operator's O&M manual.
3. Confirm that the procedures employed by contractor individuals performing covered tasks are those approved by the operator for the tasks being performed.
4. Ensure that procedure adherence is accomplished and that "work-arounds"[1] are not employed that would invalidate the evaluation and qualification that was performed for the individual in performance of the task.
5. Determine if all of the tools and special equipment identified in procedures are present at the job site and are properly employed in the performance of the task, and if techniques and special processes specified are used as described.

9.02 Qualification Status

[1] A "work-around" is a situation where the individual is using a procedure that wouldn't work the way it was written (due to an inadequate procedure or an equipment change that made the procedure steps invalid), or the individual has found a "better" way to get the job done faster instead of using the tool the way it was designed (e.g., not making depth measurements on a tapping tool because you had never drilled through the bottom of the pipe), or not taking the time to follow the manufacturer's instructions (not marking the stab depth when using a Continental coupling to join two sections of plastic pipe) because he never experienced a problem.

Are the individuals performing covered tasks currently qualified to perform the tasks?

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The name of each individual observed should be noted and a subsequent review of their qualification records performed to ensure that: 1) the individual was qualified to perform the task observed; and 2) the individual's qualifications are current. A review of the evaluation requirements contained in the operator's or contractor's OQ written program should be performed to ensure that all requirements were met for the current qualification. In addition, a review of the evaluation instruments (written tests, performance evaluation checklists, etc.) may be performed to determine if any of these contain deficiencies (e.g., too few questions to ensure task knowledge, failure to address critical task requirements). Reviews of qualification records and/or evaluation instruments should ensure that AOC evaluation has been performed.

9.03 Abnormal Operating Condition Recognition and Reaction

Are the individuals performing covered tasks cognizant of the AOCs that are applicable to the tasks observed?

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: This inspection should focus on an individual's knowledge of the AOCs applicable to the covered task being performed and the ability to recognize and react to those AOCs. The information gained during the inspection should be compared to the requirements for qualification applied by the operator or contractor during the evaluation process for the subject covered task (e.g., knowledge of task-specific AOCs in addition to generic AOCs). If contractor individuals are observed, confirm whether the AOCs identified in the operator's written program are the ones used for qualification of the contractor individual.

9.04 Verification of Qualification

Are qualification records verified at the job site to be current, and is personal identification of contractor individuals performing covered tasks checked, prior to task performance?

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: Supervisors, crew foremen or other persons in charge of field work must be able to verify that the qualifications of individuals performing covered tasks. This typically applies to individuals employed by the operator that are from another district or field office, where the qualification status may be unknown or uncertain, or to contractor individuals. Employee records should be made available through company databases or other means of verification, while contractors should be required to provide documentation of qualification prior to beginning work, and also provide a form of identification that is satisfactory to correlate the qualification documentation with the individual performing the task.

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: If the field inspection is performed subsequent to the headquarters inspection (six months or more), the OQ database or inspection records should be checked to determine if any potential issues that were identified as having implications for incorrect task performance (e.g., no skills evaluation for tasks requiring knowledge and skills; hands-on evaluations were performed as a group as opposed to individually; span of control was not specified on a task-specific basis; evaluation and qualification on changed tasks or changed procedures not performed; inadequate provisions for, or inadequate implementation of requirements for, suspension of qualification following involvement in an incident or for reasonable cause) have been corrected.

Field Inspection Notes

The following table is provided for *convenience* in recording the tasks observed and the individuals performing those tasks. Other formats, and even separate files, may also be used. This information is *not* imported into the OQ database.

No	Task Name	Name/ID of Individual Observed						Comments
		David Hill		Nicholas Deaton		Kimberly Harris		
		Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	
1	Pipe to soil readings	N	N	N	Y	Y	Y	
2	Rectifier Readings	N	N	N	Y	Y	Y	
3	Bond readings	N	N	N	Y	Y	Y	
4	Check external corrosion	N	Y	N	Y	N	Y	
5	Line Location	N	Y	N	Y	N	N	
6	Maintain Line Markers	N	Y	N	Y	N	N	
7								
8								

Example table use (can be deleted):

No	Task Name	Name/ID of Individual Observed						Comments
		Bill Smith		Mary Jones		Clint Nelson		
		Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	Performed (Y/N)	Qualified (Y/N)	
1	Cathodic Reading	Y	Y					
2	Critical Valve Operation			Y	Y	Y	N	Clint Nelson lacked required training.

Activity ID#
117856

RECEIVED MAY 2 5 2006

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.**

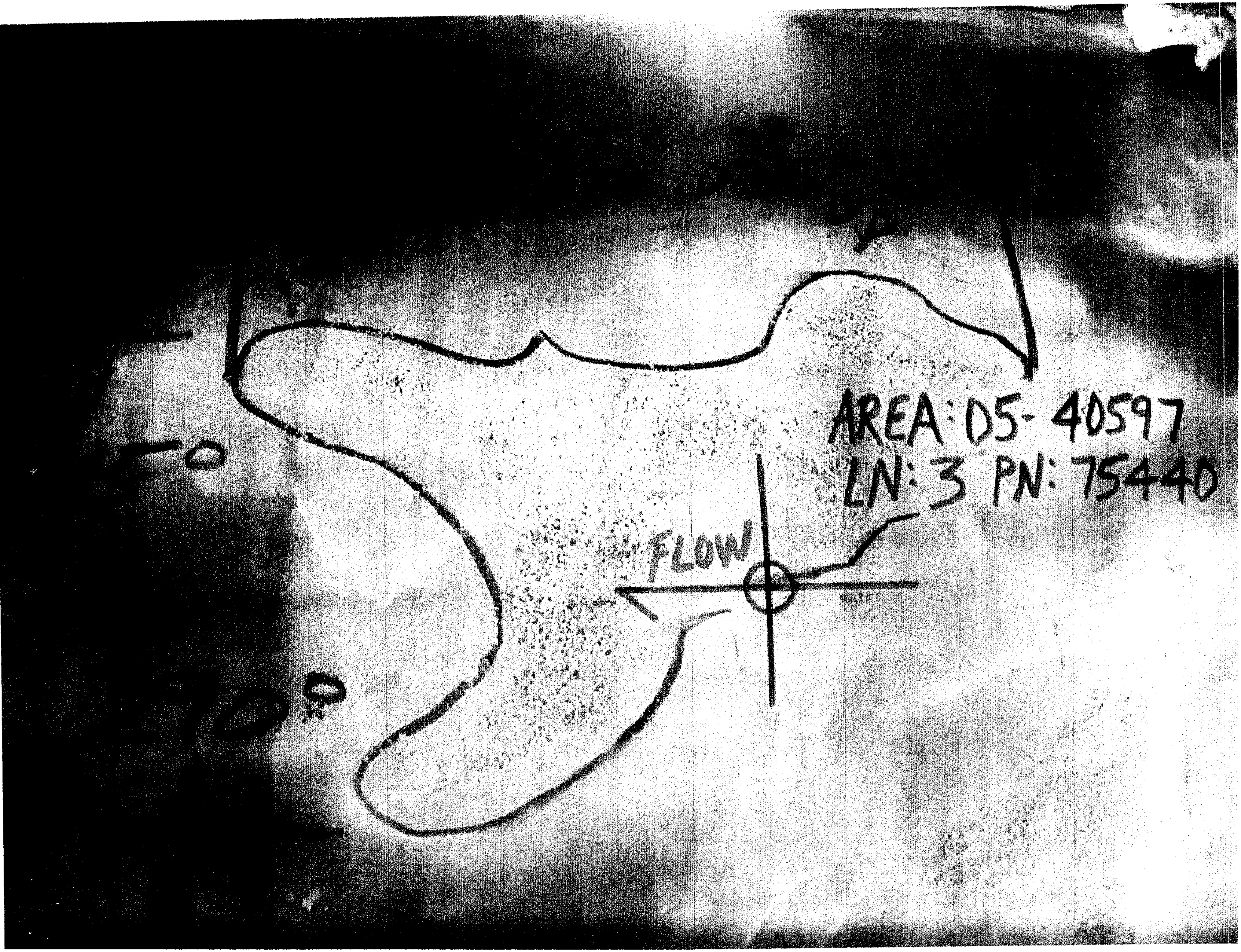
Inspection Report		**Post Inspection Memorandum**
Inspector/Submit Date:	May 05, 2006	**Inspector:** Boyd Haugrose, MNOPS
Peer Review/Date:	5/22/06	**Peer Reviewer:**
Director Approval/Date:		**Director Approval**

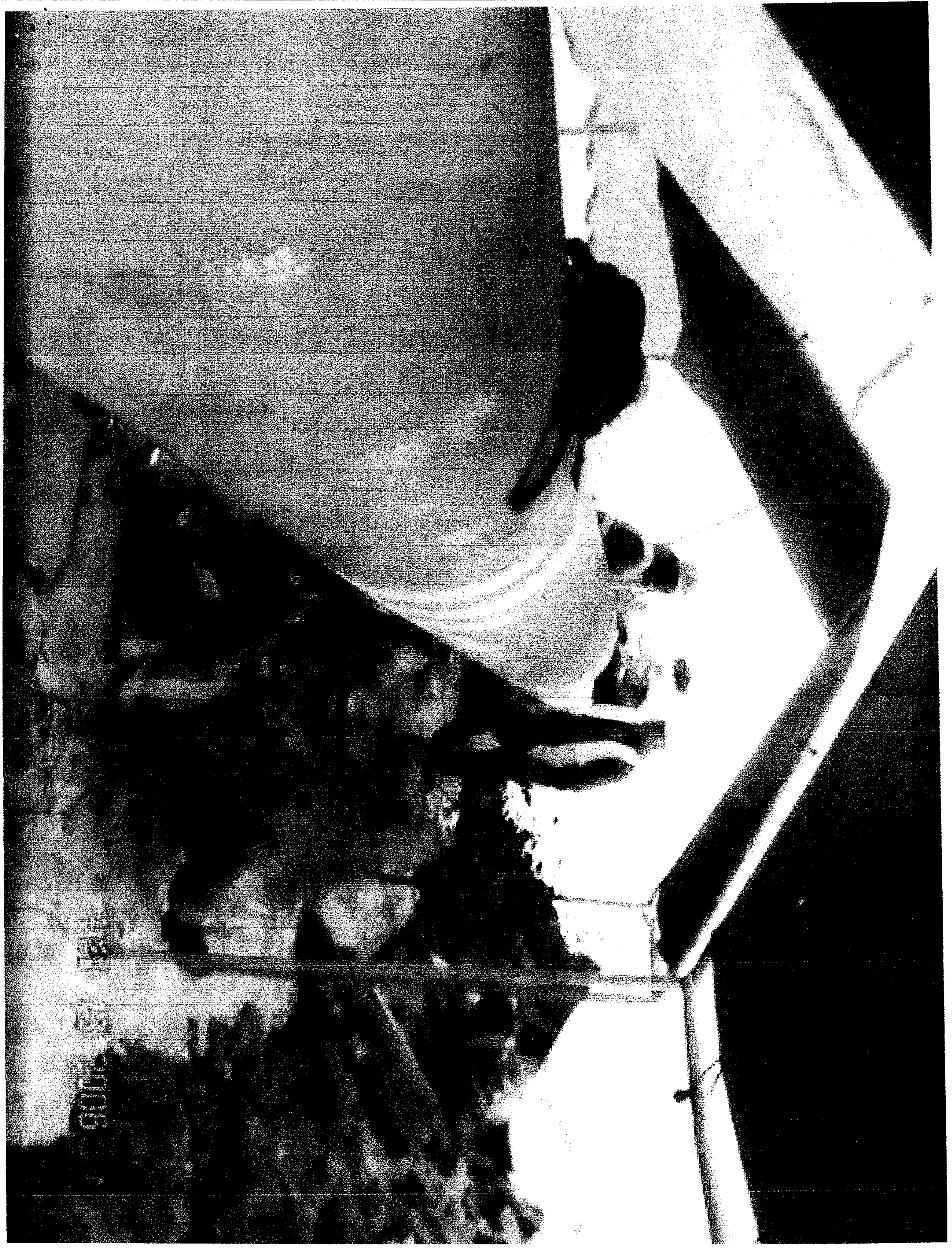
POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Company, Inc.		**OPID #:11169**
Name of Unit(s):	ND - Clearbrook		**Unit #(s):** 3083
Records Location:	119 N. 25th St East, Superior, WI		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil		
Inspection Type:	Integrity Management 410, Field – Crack Anomaly Investigations	**Inspection Date(s):**	See Below
For OPS :			**AFO Days:**
For MNOPS :	Boyd Haugrose		**AFO Days:** 11
MNOPS CASE #: 006305			

Inspection Dates:
January 19, 20, February 2, 7, 8, 9, 10, 14, 16, 23, April 27, 2006

Summary:
This memorandum relates to Enbridge Energy's 2005 Crack Investigation program as it relates to its Integrity Management Plan. The memorandum focuses on that portion of the investigation that resulted from identified anomalies detailed by the 2001and 2005 PII Ultrascan CD ILI tool runs from Gretna to Superior, WI.

Five dig sites were identified within Minnesota from the North Dakota Border to the Clearbrook Terminal near Clearbrook, MN. MNOPS Inspector Boyd Haugrose observed the excavation, assessment, remediation and backfill operations at least partially on the 5 sites as time allowed. Two interviews were conducted within the area headquarters at Bemidji, MN, with Larry Sands, the Enbridge Project Coordinator.


AREA: 05-40597
LN: 3 PN: 75440
FLOW



RECEIVED APR 2 4 2006

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 31, 2006 REV'D 041706	**Inspector:**	Brian Pierzina, Senior Engineer
Peer Review/Date:	4/17/06	**Peer Reviewer:**	[signature]
Director Approval/Date:		**Director Approval**	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Enbridge Energy Company, Inc.	**OPID #:**	11169
Name of Unit(s):	Clearbrook - Deer River, Deer River – Superior	**Unit #(s):**	3083
Records Location:	119 North 25th Street East, Superior, Wisconsin		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil		
Inspection Type:	Field – Crack Anomaly Investigations	**Inspection Date(s):**	See Below
For OPS :		**AFO Days:**	
For MNOPS :	Brian Pierzina	**AFO Days:**	(19)
MNOPS CASE #: 005817			

Inspection Dates:
January 10, 13, 17, 19, 20, 25, 26, 27, 30, 31, February 1, 2, 3, 8, 10, 13, 22, 23, March 8, 2006

Summary:
This report is related to the 2006 Crack Investigation Program conducted by Enbridge Energy Company on the 34 inch Line 3 between Clearbrook, Minnesota and Superior Wisconsin. The dig/repair program resulted from a 2005 ILI tool run using the PII UltraScan CD tool.

There were a total of 59 dig sites involving 408 reported anomalies. Eleven of the dig sites were in HCAs. The reported anomalies were predominantly linear defects affecting the longitudinal seam of A.O. Smith flash weld pipe, and U.S. Steel SAW pipe, or crack fields (SCC) on the pipe body. Many of the defects that were investigated did not require repair. In addition, many of the repairs that were made, were made because the repair was more practical than other mitigation options, such as grinding extensive lengths of SCC.

There were at least two defects requiring repair that were not reported by the tool vendor, but were discovered as a result of other anomaly investigations. One was a short longitudinal crack across a girth weld at or near MP 972, and the other was an ID connected hook type defect(s) near MP 1032. In general, the tool reported defects could be confirmed during the field investigation, although in many cases the actual depths were less than reported, hence no repair was required.

Enbridge used a combination of their own PLM personnel and contractors to perform the work, with Minnesota Limited doing most of the work in the center part of the state, and UPI doing most of the work downstream from Wawina to Superior. They also used an additional contractor in Wisconsin. Contract crews had inspectors on site, as well as Project Coordinators from Enbridge managing the program. NDT was performed by Pfinde, using FAST ultrasonic inspection, and magnetic particle inspection (MPI). All personnel involved seemed to be familiar with applicable procedures and requirements, and associated safety precautions. Information was freely exchanged by Enbridge representatives, which was extremely helpful, considering the number of locations work was taking place.

Based on discussions during the planning for Enbridge's upcoming IMP Audit, MNOPS also completed the Hazardous Liquid IMP Field Verification Inspection Form at the request of SW Region personnel. The project seemed like a good application to use the form, and see how it fits into a typical dig program. The completed form is attached. Also included is a CD containing various photographs of the project. There were no violations identified as a result of this inspection.

In conjunction with these activities, a meeting was held February 1, 2006 in Kansas City, where Enbridge representatives discussed the status of their crack investigation program in conjunction with the Return to Service Plan that was established following the July 4, 2002 Line 3 rupture in Cohasset. Enbridge has requested the remaining pressure restriction resulting from that rupture be removed, based on their mitigation efforts through ILI, inspection and repair.

US Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

Hazardous Liquid IMP Field Verification Inspection
49 CFR Parts 195.450 and 195.452

General Notes:

1. This Field Verification Inspection is performed on field activities being performed by an Operator in support of their Integrity Management Program (IMP).
2. This is a two part inspection:
    i. A review of applicable Operations and Maintenance (O&M) and IMP processes and procedures applicable to the field activity being inspected to ensure the operator is implementing their O&M and IMP Manuals in a consistent manner.
    ii. A Field Verification Inspection to determine that activities on the pipeline and facilities are being performed in accordance with written procedures or guidance.
3. Not all parts of this form may be applicable to a specific Field Verification Inspection, and only those applicable portions of this form need to be completed. The applicable portions are identified in the Table below by a check mark. For those applicable sections, mark the form "Satisfactory"; "Unsatisfactory"; or Not Checked ("N/C").

Operator Inspected: Enbridge Energy Company
Op ID: 11169 – OPS Unit 3083

Perform Activity *(denoted by mark)*	Activity Number	Activity Description
X	1A	In-Line Inspection
	1B	Hydrostatic Pressure Testing
	1C	Other Assessment Technologies
X	2A	Remedial Actions
X	2B	Remediation – Implementation
	3A	Installed Leak Detection System Information
	3B	Installed Emergency Flow Restrictive Device
X	4A	Field Inspection for Verification of HCA Locations
X	4B	Field Inspection for Verification of Anomaly Digs
	4C	Field Inspection to Verify adequacy of the Cathodic Protection System
X	4D	Field inspection for general system characteristics

Hazardous Liquid IMP Field Verification Inspection Form

Name of Operator: Enbridge Energy Company

Headquarters Address:
1100 Louisiana Avenue, Suite 3200
Houston, TX 77002

Company Official: Dan Tutcher

Phone Number: 713-821-2054

Fax Number: 713-653-8711

Operator ID: 11169

Activity ID: 3083

Persons Interviewed	Title	Phone No.	E-Mail
Mike Goman	**Sr. Compliance Coordinator Primary Contact**	715-394-1523	mike.goman@enbridge.com
Patsy Bolk	Compliance Coordinator	715-394-1504	Patsy.bolk@enbridge.com
Craig Goplin	Project Coordinator	218-591-1118	craig.goplin@enbridge.com
Ron Hautamaki	Project Coordinator	218-391-0096	ron.hautamaki@enbridge.com
Larry Sand	Project Coordinator	218-766-9593	larry.sand@enbridge.com

OPS/State Representative(s): _Brian Pierzina Dates of Inspection: 1/10,13,17,19,20,25,26,27,30,31/06, 2/1,2,3,8,10,13,22,23/06, 3/8/06

Inspector Signature: ___________________________

System Descriptions:
Inspection relates to 34 inch Line 3 from Clearbrook, MN to Superior, WI. Crude oil pipeline system with pumping stations at Clearbrook, Cass Lake, Deer River, and Floodwood, MN. Pipeline has a history of longitudinal seam failures, and was recently inspected with the PII USCD tool for the second time since 2002, following a 7/4/02 rupture at MP 1002.73, in Cohasset, MN.

Site Location of field activities:
Various dig sites (appr. 50) between Clearbrook, MN and Superior, WI. MNOPS only attended digs in Minnesota. Inspection days also include a 2/1/06 meeting with Enbridge, Central Region and MNOPS personnel to discuss the status of crack detection efforts, and any other concerns related to removal of the final pressure restriction resulting from the Cohasset rupture.

Key Documents Reviewed:

Document Title	Document No.	Rev. No	Date
UltraScan CD Final Report	Run ECS205		9/30/05
Enbridge – Line 3 Clearbrook to Superior Internal Inspection Questionaire			10/17/02
Enbridge O&M Book 3 – 06-04-01 Appendix (Pressure Restriction for Pipeline Inspection/Repair	Book 3 06-04-01 Appendix		12/19/05
Enbridge O&M Book 4 – Welding 02-02-02	Book 4 02-02-02		5/2/05
Enbridge Spreadsheet – Line 3 Crack Digs Clearbrook - Superior			3/8/06

art 1 - Performance of Integrity Assessments

	Satisfactory	Unsatisfactory	N/C	Notes
erify that Operator's O&M and IMP procedural :quirements (e.g. launching/receiving tools) for erformance of ILI were followed.	X			Notes: Launching and receiving procedures are in Book 3 Sections 08-03-01 and 08-03-02, respectively. MNOPS was not present for the tool run. Tool System and calibration checks are addressed in the Final Report to Enbridge, as well as speed of travel and rotational movement. The CD tool was run April 29 – May 2, 2005, and had an average speed of 4.27 ft/sec. The tool sensors were calibrated for the crude product that would be in the line (HSB). A Caliper Tool run was not required due to the recent run from 2002. Girth welds were correlated to the 2002 USCD tool run.
Verify Operator's ILI procedural requirements were followed (e.g. operation of trap for launching and receiving of pig, operational control of flow), as appropriate.				
Verify ILI tool systems and calibration checks before run were performed to ensure tool was operating correctly prior to assessment being performed, as appropriate.				
Verify ILI complied with Operator's procedural requirements for performance of a successful assessment (e.g. speed of travel within limits), as appropriate.				
Document ILI Tool Vendor and Tool type (e.g. MFL, Deformation). Document other pertinent information about Vendor and Tool, as appropriate				
Other:				

	Satisfactory	Unsatisfactory	N/C	Notes
'erify that hydrostatic pressure tests complied with 'art 195 Subpart E requirements.			X	Notes:
Review documentation of Hydrostatic Pressure Test parameters and results. Verify test was performed without leakage and in compliance with Part 195 Subpart E requirements.				
Review test procedures and records and verify test acceptability and validity.				
Review determination of the cause of hydrostatic test failures, as appropriate.				
Document Hydrostatic Pressure Test Vendor and equipment used, as appropriate.				
Other:				

	Satisfactory	Unsatisfactory	N/C	Notes
/erify that application of "Other Assessment 'echnology" complied with Operator's requirements, hat appropriate notifications had been submitted to)PS, and that appropriate data was collected.			X	Notes:
Review documentation of notification to OPS of Operator's application of "Other Assessment Technology". Verify compliance with Operator's procedural requirements and performance of assessment within parameters originally submitted to OPS.				
Verify that appropriate tests are being performed and appropriate data is being collected, as appropriate.				
Other.				

Part 3 - Preventive and Mitigative Actions

	Satisfactory	Unsatisfactory	N/C	Notes: Enbridge has had a leak detection system installed for Line 3 for some time. The system continuously monitors the pipeline for leaks.
Identify installed leak detection systems on pipelines and facilities that can affect an HCA.			X	
Document leak detection system components installed on system to enhance capabilities, as appropriate.				
Document the frequency of monitoring of installed leak detection systems and verify connection of installed components to leak detection monitoring system, as appropriate,				
Other:				

	Satisfactory	Unsatisfactory	N/C	Notes: Enbridge has been converting a number of manually operated valves to remotely operated valves. These installations are a part of their Volume Out risk analysis within their IMP, but not related to this project.
Verify additional preventive and mitigative actions implemented by Operator.			X	
Document Emergency Flow Restrictive Device (EFRD) component(s) installed on system. Note that EFRD per §195.450 means a check valve or remote control valve as follows: (1) Check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction. (2) Remote control valve or RCV means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.				
Document the frequency of monitoring of installed EFRDs and verify connection of installed components to monitoring/operating system, as appropriate.				
Comment on the perceived effectiveness of the EFRD in mitigating the consequences of a release on the HCA that it is designed to protect.				
Other:				

Part 4 - Field Investigations (Additional Activities as appropriate)

4A. Field Inspection for Verification of HCA Locations	Satisfactory	Unsatisfactory	N/C	Notes
Review HCAs locations as identified by the Operator. Utilize NPMS, as appropriate.	X			Notes: Of the 59 dig sites involved in the project, 11 were in HCAs. No discrepancies were identified as a result of field observations.
Verify population derived HCAs in the field are as they appear on Operator's maps and NPMS, as appropriate. Document newly constructed (within last 2-3 years) population and/or commercial areas that could be affected by a pipeline release, as appropriate. Note that population derived HCAs are defined in §195.450				
Verify drinking water and ecological HCAs in the field are as they appear on Operator's maps and NPMS, as appropriate. Document newly established drinking water sources and/or ecological resources areas (within last 2-3 years) that could be affected by a pipeline release. Note that unusually sensitive areas (USAs) are defined in §195.6				
Verify commercially navigable waterway HCAs in the field are as they appear on Operator's maps and NPMS, as appropriate. Document any activity (commercial in nature) that could affect the waterways status as a commercially navigable waterway, as appropriate. Note that commercially navigable waterway HCAs are defined in §195.450				

[illegible]	Satisfactory	Unsatisfactory	N/C	Notes
Verify repair areas, ILI verification sites, etc.	X			Notes: The dig program involved 59 dig sites to address 408 reported anomalies. 11 of the dig sites were in HCAs. Additional digs may be issued in the future.
Identify anomaly dig sites in the area, if possible, that will not be investigated as part of this field activity (e.g. three other digs to be performed in this area, but not part of this inspection)				

[illegible]	Satisfactory	Unsatisfactory	N/C	Notes:
In case of hydrostatic pressure testing, Cathodic Protection (CP) systems must be evaluated for general adequacy.			X	
Review records of CP readings from CIS and/or annual survey to ensure minimum code requirements are being met, if available.				
Review results of random field CP readings performed during this activity to ensure minimum code requirements are being met, if possible.				
Perform random rectifier checks during this activity and ensure rectifiers are operating correctly, if possible.				

4D. Field Inspection for general system characteristics	Satisfactory	Unsatisfactory	N/C	Notes
Through field inspection determine overall condition of pipeline and associated facilities for a general estimation of the effectiveness of the operator's IMP implementation.	X			Notes: The pipeline was built between 1964 and 1967 with primarily A.O. Smith and U.S. Steel pipe. It is predominantly coated with Polyken Tape, and has experienced significant disbondment. Numerous longitudinal seam failures have been experienced throughout the operating history of the pipeline. The operator has been actively involved in the development of crack detection technology through ILI. All other conditions associated with the ROW and observed facilities were acceptable.
Visit nearby pump stations, valve settings, aboveground crossings, etc. to ensure minimum code requirements are being met, if possible and as appropriate.				
Evaluate condition of the ROW to ensure minimum code requirements are being met, as appropriate.				
Comment on Operator's apparent commitment to the integrity and safe operation of their system, as appropriate.				
Other				

Post Inspection Memorandum (PIM)

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Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	December 20, 2005	**Inspector:**	Brian Pierzina
Peer Review/Date:	12/19/05	**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 - Deer River	**Unit #(s):**	3083
Records Location:	119 North 25th Street East, Superior, Wisconsin		
Unit Type & Commodity:	Interstate Hazardous Liquid – Crude Oil		
Inspection Type:	Integrity Management 410	**Inspection Date(s):**	12/7,14/2005
For OPS :		**AFO Days:**	
For MNOPS :	Brian Pierzina	**AFO Days:**	(2)
MNOPS CASE #: 005817			

Summary:

On December 7, 2005 Brian Pierzina drove to Clearbrook, where Enbridge was going to be investigating crack indications downstream of the Clearbrook Terminal. However, Enbridge's plans had changed due to operational considerations, and the investigations were post-poned until later. Craig Goplin, Project Coordinator for Enbridge, apologized for the mix-up, as he had forgotten to pass this information along. He said they would instead begin their investigations downstream of Cass Lake, around MP 972, next week.

On December 14, 2005, BEP met the crew at dig site #2 (MP 971.8131), where three features were going to be inspected. The inspection at dig site #1 (MP 971.7201), just upstream, had been completed the previous day, and was a re-coat, meaning no repair was necessary. Dig site #2 was in the same area of crack investigations in 2003, following the Cohasset rupture. The downstream defect was identified by NDT as a lamination, just as it had been in 2003. The tool analysis seemed to indicate it was a surface breaking defect, but ultrasonic and magnetic particle testing did not indicate any surface defects. The upstream feature also did not require repair, but upon further inspection of some external corrosion, the NDT technician identified a longitudinal crack through the girth weld that required a four foot repair sleeve. This was not the tool reported defect. The crack was approximately one half inch long, and of undetermined depth. It would have been necessary to grind on the weld to get an accurate depth measurement, and personnel on site determined they would just install a repair sleeve, in order to avoid grinding on the girth weld. The third feature was an undetermined anomaly associated with the long seam in the A.O. Smith pipe. It appeared the seam may have been ground at the factory. Ultrasonic inspection identified an inclusion approximately 3 inches long, that the operator decided to repair with a sleeve. The repair work will continue into next week.

Some of the pending crack investigations are in wet areas, and Enbridge is attempting to freeze down the access roads to minimize the need for swamp mats. This work will likely continue through the holidays, so it's not expected that anymore features will be evaluated until after the first of the year. MNOPS will provide further updates once the crack investigation program resumes.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Inspection Report	**Post Inspection Memorandum**
Inspector/Submit Date: 1-4-06	**Inspector/Submit Date:** 10-12-05 **Peer Review/Date:** 10-13-05 **Director Approval/Date:** 10/17/05

POST INSPECTION MEMORANDUM (PIM)	
Name of Operator: Enbridge	**OPID #:** 11169
Name of Unit(s): Superior and Escanaba	**Unit # (s):** 1323 and 1353
Records Location: Superior, WI	
Unit Type & Commodity: Interstate Liquid – Crude Oil and Natural Gas Liquids	
Inspection Type: IO1 Unit Inspection	**Inspection Date(s):** 9/05 to 9/09/05 and 9/19 to 9/23/05
OPS Representative(s): Joshua Johnson	**AFO Days:** 10

Summary:

Records review was performed at Enbridge's Superior Office with Steve Sweney and Brian Pierzina of the Minnesota Office of Pipeline Safety from September 6-7. On September 8-9, the field portion of the Superior Unit was performed including lines 1, 2, 3 and 4 from the Minnesota border to Superior Station, Superior Station, and line 5 from Superior Station to Ino Station.

The week of September 19- 23 the field review of the Escanaba unit was performed – which covered from near Lewiston, MI to past Gogebic Station covering approximately 285 pipeline miles. The following stations were also audited: Indian River, Mackinaw, North Straights, Naubinway, Gould City, Manistique, Rapid River, Iron River, and Gogebic.

Findings:

Office Records – All records reviewed for the Superior and Escanaba units appeared to be satisfactory. Several mainline valve inspections records were confusing (valves marked open and closed) and Enbridge will redesign their forms to clarify this in the future. The Minnesota inspectors had a couple of issues with possible missing public officials, late telephonic reports on a tank leak in Clearbrook, and not notifying the police as required by their procedures after the February 2004 release near Grand Rapids.

Field Review – All cathodic protection readings were adequate and all above ground facilities were in good shape with minimal surface corrosion. Right of way was prominently in good condition with some brush and small trees in some locations which were on the maintenance schedule to be cleared. Two pipeline markers had old Lakehead markers on one side and new Enbridge markers on the side facing the road. The number on the Lakehead markers connects to the Enbridge Control Center.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: Enbridge Energy, Limited Partnership	
OP ID No. [1] 11169	**Unit ID No.** [1] 1323 and 1353
H.Q. Address:	**System/Unit Name & Address:** [1]
1100 Louisiana Street Suite 3300 Houston, TX 77002-5217	Enbridge Pipelines (Lakehead) L.L.C. 119 N. 25th Street East Superior, WI 54880
Co. Official: Dan C. Tutcher	**Activity Record ID#:** 115014 & 115012
Phone No.: 713-650-8900	**Phone No.:** 715-394-1400
Fax No.: 713-653-6711	**Fax No.:** 715-394-1500
Emergency Phone No.: 800-858-5253	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Mark Willoughby	Manager, Compliance	715-394-1534
Mike Goman	Senior Compliance Coordinator	715-394-1523
Jay Johnson	Compliance Coordinator	715-394-1512
Patsy Bolk	Compliance Analyst	715-394-1504
		Others on included sheet

OPS Representative(s) [1] Joshua Johnson	**Inspection Date(s)** [1] **Sept 6-9 and Sept 19-23, 2005**
Company System Maps (copies for Region Files):	Previously provided

Unit Description:

The Superior Unit consists of the former Lakehead Pipeline in Wisconsin, beginning at the Minnesota border, and concluding at Superior Terminal. It included 18, 26, 34, and 36 inch pipeline primarily transporting crude oil as well as NGL in the 18" pipeline and includes a tank farm at Superior. The unit also consists of the 30" line #5 from MP 1098.10 (Superior Terminal) to MP 1137.3 (Ino Station) The Escanaba Unit consists of the 30" line #5 from MP 1137.32 (Ino Pump Station.) to 1548.60 (Lewiston pump station) and includes the Indian River, Mackinaw, North Straights, Naubinway, Gould City, Manistique, Rapid River, Iron River, and Gogebic pump stations.

Portion of Unit Inspected [1]

The inspection consisted of record review at the Superior Office, and field review of pumping stations and other facilities along the pipeline ROW.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections. If the inspection is in the OPS Joint O&M inspection 5 year period, procedures necessitated by new or amended regulations

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

placed in force after the Joint Team O&M Inspection, and those known to have changed since the Joint Team Inspection, should be reviewed. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 2/25/00 and 2/25/05.

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CONVERSION TO SERVICE		S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				X

Comments:
This item was not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
*	.49	NLT June 15, 2005, operator must complete Annual Report and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Amdt 195-80 pub. 1/06/04, eff. 2/05/04.				X
* .402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)). Amdt 195-75 pub. 1/08/02, eff. 2/07/02				X
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
This item was not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.						
* .402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				X
		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				X
		Welding procedures must be qualified by destructive testing.				X

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		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2001 Ed.)**, except that a welder qualified under an earlier edition than listed in §195.3 may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 192-81 corr. Pub. 9/09/04.				X
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	.226(a)	Arc burns must be repaired.				X
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				X
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				X
	Nondestructive Testing Procedures					
*	.228 /.234	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per **§195.228(b)** and per the requirements of **§195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				X
	.234(b)	Nondestructive testing of welds must be performed:				X
		1. In accordance with written procedures for **NDT**				X
		2. By qualified personnel				X
		3. By a process that will indicate any defects that may affect the integrity of the weld				X
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				X
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 6 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be pressure tested.				X
	.302(b)	Except for lines converted under §195.5, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				X
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				X
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				X
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				X

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		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				X
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				X
	.303	Procedures for the risk based alternative to pressure testing?				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with §195.302.				X
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph (a) of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
*	.310(b)(10)	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
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			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:

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Comments:
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		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				X
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				X
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				X
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				X
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?				X
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				X
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				X
*		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per §195.59. Amdt 195-69 pub. 9/8/00, eff. 10/10/00.				X
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				X
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				X
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				X
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				X

Comments:
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		ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				X
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				X
		iii. Loss of communications?				X

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
		iv. The operation of any safety device?				X
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				X
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:
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EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under §195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X

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	EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)		S	U	N/A	N/C
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				X
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				X
	.403(b)(2)	Make appropriate changes to the emergency response training program				X
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				X

Comments:
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	MAPS and RECORDS PROCEDURES		S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				X
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				X
		ii. Pump stations				X
		iii. Scraper and sphere facilities				X
		iv. Pipeline valves				X
		v. Facilities to which §195.402(c)(9) applies				X
		vi. Rights-of-way				X
		vii. Safety devices to which §195.428 applies				X
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				X
	.404(a)(3)	The maximum operating pressure of each pipeline.				X
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				X
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				X
	.404(b)(1)	The discharge pressure at each pump station.				X
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under §195.402 apply.				X
	.404(c)	Each operator shall maintain the following records for the periods specified:				X
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				X
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				X
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				X

Comments:

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		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by §195.106.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	80% of the test pressure (Subpart E).				X
	.406(a)(4)	80% of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	80% of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **§195.402(c)(9)**.				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		LINE MARKER PROCEDURES	S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
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INSPECTION RIGHTS-of-WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				X
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years.**				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				X
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times.				X
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year.				X
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				X

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Comments:
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		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				X
		2. **HVL** pipelines at intervals not to exceed 7½ **months**, but at least **twice** each calendar year.				X
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				X
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				X
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				X
		The equipment must be:				
		a. In proper operating condition at all times.				X
		b. Plainly marked so that its identity as firefighting equipment is clear.				X
		c. Located so that it is easily accessible during a fire.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				X

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BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 4 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **§195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years.				X
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.**				X
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

SIGN PROCEDURES			S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

SECURITY of FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
This item was not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

SMOKING OR OPEN FLAME PROCEDURES			S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:
This item was not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a)	.440	Is there a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				X
		Is the program conducted in English and other languages where appropriate?				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				X
	.442(b)	Does the operator participate in a qualified One-Call program?				X
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				X
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				X
		ii. How to learn the location of underground pipelines before excavation activities are begun.				X
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				X
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				X
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				X
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				X
		ii. In the case of blasting, any inspection must include leakage surveys.				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				X

Comments:
This item was not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

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PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				X

*	SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01; eff. 1/28/02)		S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered.				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-96** (incorporated by reference).				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months).**				X
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months).**				X
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-96.**				X
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				X
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				X
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.**				X
		Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				X
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**				X
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				X
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b).**				X
	.575	Are there adequate provisions for electrical isolations?				X
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects.				X
		b. Design & install CP systems to minimize effects on adjacent metallic structures.				X
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				X
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				X
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**				X
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				X
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				X
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				X
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				X
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				X
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				X
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)** ?				X

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*	SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)		S	U	N/A	N/C
	.589	Corrosion Control Records Retention (Some are required for 5 yrs; Some are for the service life).				X

Comments:
These items were not checked because the focus of the inspection was field and records, and a headquarters O&M inspection had been conducted previously.

Alert Notices:
What process does the Operator have to address Alert Notices?

Comments:
Patsy Bolk receives these from WinDot and sends them out to the appropriate individuals in the company.

Recent Pipeline Safety Advisory Bulletin
ADB-04-03 in August 18, 2004 Federal Register, pp. 51348-51349 (Ref. **fr18au04N Pipeline Safety: Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities)**
Reference http://www.gpoaccess.gov/fr/advanced.html

Best Practice: Stress Corrosion Cracking
Pipeline Safety Advisory Bulletin ADB-03-05 in October 8, 2003 Federal Register, pp. 58166-58168 (Ref. **fr08oc03N Pipeline Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Liquid Pipelines**).
Reference http://www.gpoaccess.gov/fr/advanced.html

Is the operator aware of the SCC bulletin, and is the operator reviewing their system for the potential of SCC? Y/N **Yes**

PART 195 - FIELD REVIEW		S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory	X			
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers	X			
.412	River Crossings	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			

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	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings - Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks	X			
.434	Signs - Pumping Stations - Breakout Tanks	X			
.436	Security - Pumping Stations - Breakout Tanks	X			
.438	No Smoking Signs	X			
.501-.509	Operator Qualification Questions, Observations - See Attachment 3	X			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)	X			

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	X			
.52	Telephonic Reports to NRC (800-424-8802)	X			
.54(a)	Written Accident Reports (DOT Form 7000-1)	X			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	X			
.56	Safety Related Conditions	X			
.57	Offshore Pipeline Condition Reports			X	
.59	Abandoned Underwater Facility Reports			X	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	X			
.214(b)	Test Results to Qualify Welding Procedures	X			
.222	Welder Qualification	X			

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.234(b)	Nondestructive Technician Qualification	X			
.589	Cathodic Protection	X			
.266	Construction Records	X			
.266(a)	Total Number of Girth Welds	X			
	Number of Welds Inspected by NDT	X			
	Number of Welds Rejected	X			
	Disposition of each Weld Rejected	X			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	X			
.266(c)	Location of each Crossing with another Pipeline	X			
.266(d)	Location of each buried Utility Crossing	X			
.266(e)	Location of Overhead Crossings	X			
.266(f)	Location of each Valve and Test Station	X			
PRESSURE TESTING					
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			
.308	Records of Pre-tested Pipe	X			
OPERATION & MAINTENANCE					
.402(a)	Annual Review of O&M Manual **(1 per yr/15 months)**	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities			X	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes **(1 per yr/15 months)**	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)	X			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).	X			
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/7½ months** HVL)	X			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			
.440	Public Education	X			
DAMAGE PREVENTION PROGRAM					
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
CORROSION CONTROL					
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)	X			
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)	X			
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks	X			
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment (**2 per yr/7½ months**)	X			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)	X			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:
Items marked "N/A" did not apply to the operator's facilities in these units. There were no violations identified as a result of the field or records review of the units audited.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]			
194.111	RSPA Tracking Number: Approval Date:			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]			
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]			
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]			

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*
This item was not reviewed as part of this inspection.0

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1
SCADA Liquid Worksheet

If an item is found to be unsatisfactory, an explanation must be included in this report.

The topics on this worksheet regard general SCADA functionality. A more thorough SCADA evaluation may be warranted based on the results of this worksheet or prompts by other events.

1. Pipeline Safety Advisory Bulletins (reference http://www.gpoaccess.gov/fr/advanced.html)

Review the following with the operator:

• Advisory Bulletin ADB-99-03 in July 16,1999 Federal Register p.38501 (Ref.**fr16jy99N Potential Service Interruptions in Supervisory Control and Data Acquisition Systems**) - discuss SCADA system performance.

• Advisory Bulletin ADB-03-09 in December 23, 2003 Federal Register, pp. 74289-74290 (Ref. **fr23de03N Pipeline Safety: Potential Service Disruptions in Supervisory Control and Data Acquisition Systems**) – discuss consideration of possible SCADA system disruptions caused by system maintenance or upgrade.

Comments:

System Performance –Enbridge monitors the general health of each SCADA servers and they are checked and signed off each working day.

Disruptions caused by system maintenance or upgrade – Enbridge has several SCADA servers in which an operator is controlling one on. Most system upgrades or maintenance is done on a backup server and when the operators are ready they can switch control to that backup server. All changes made to a production system are tested in a test environment first.

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. 195.402(d)(1)(iii) - Loss of communications.

- Off-site Back-up Center
- Data transfer to redundant or off-site processors
- Battery and/or Emergency Generator
- Redundant data communications paths, automatic restoration or manual?
- Data Reduction & Archiving
- Indication of stale, forced or manually overridden data, or system lock-up
- Operating practices during data communications outages

Comments:

- Enbridge's SCADA systems do have an off-site back-up center.
- All field and operator entered data is transferred to the off-site data center (hot standby's).
- Enbridge has UPS and an emergency Generator for our SCADA systems.
- The data communications paths are redundant so all systems are getting live data.
- The SCADA data is archived on each SCADA server so the off-site back-up center has a copy as well as the main center.

Operators have a visual indication of bad quality, forced, and manually overridden data. As well, the operators can tell if there is a system lockup because they are always viewing the plc heartbeats. If these stop updating they will know there is a system lockup. There are also clocks on the key displays to make sure the screens are updating.

3. §195.404 - Pump station discharge pressure records.

- Discharge Pressure records in SCADA or at field locations?
- Data Reduction & Archiving
- Data acquisition frequency

Comments:

- Discharge pressures are stored in our SCADA system. Each SCADA server will have a copy of the history that includes discharge pressure. History is taken every 20 seconds.

4. §195.404 Maps and records.

Attachment 1
SCADA Liquid Worksheet

If an item is found to be unsatisfactory, an explanation must be included in this report.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of the following pipeline facilities:
(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c) (9) applies;

(vii) Safety devices to which §195.428 applies.

(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations.
- Ensure pipeline safety parameters are current (i.e., MOP, alarm set points, etc.)
- Review any emergency or abnormal operating condition or schedule deviation records generated by the SCADA system (alarm logs, trending data, etc.). Compare abnormal operating conditions noted in the SCADA data with the operator's report and reporting procedures as related to those abnormal operating conditions.
- Data Reduction & Archiving
- Data acquisition frequency

Comments:
- SCADA screen changes are verified and signed off by operations
- Safety parameters are within the SCADA system and it is the responsibility of the CCO to set them.
- Each SCADA server will have a copy of the history.

History is taken every 20 seconds and alarm logs are real time. Historical data is archived for over 5 years.

5. §195.408 - Communications.

(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system

(b)(1) Monitoring operational data as required by §195.402(c)(9)
- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-short Reports
- Maintaining pressures within limits described in **§195.406 Maximum Operating Pressure**

Comments:
- Quality of data is monitored and displayed to operators.
- Analogs must stay within their designed range or the operator will get an alarm.
- Alarms are logged and the operators have several different ways to view their alarms.
- We also log commands the same way as alarms and the operators can view them as well.

There is logic within our PLC's to make sure pressures stay within their limits.

6. §195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance
- Over-Short Reports
- Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments:
Enbridge employs real time transient models (RTTM) on our all pipelines. We have in total, 18 RTTMs that function as our CPM systems on our pipelines. The CPM systems at Enbridge meet the requirements of not only DOT Part 195 and API 1130, but also the requirements of NEB's Onshore Pipeline Regulations and CSA Z662 Appendix E.

The system performs a material balance at 5 minute, 20 minute and two hour intervals. Each 'window' provides for a progressively smaller leak detection threshold. The systems provide leak detection during all operating conditions: steady state, shutdown and

Attachment 1
SCADA Liquid Worksheet

If an item is found to be unsatisfactory, an explanation must be included in this report.

Comments:
transient. Each system is tuned to the specific pipeline, its operation and to accommodate the fluids shipped in that line.

§195.420 & .428 - Testing of applicable SCADA controlled valves, safety devices, and overfill systems functionality.

- Frequency of testing
- Inclusion of SCADA component in the tests

Comments:
All SCADA changes and additions are tested end to end before operators will use them on the running pipeline. Frequency of tests after that is left up to CCO to do. SCADA components are tested in a test environment before each upgrade is performed.

Attachment 2
Internal Corrosion Worksheet - Liquid Pipelines

If an item is found to be unsatisfactory, an explanation must be included in this report.

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: X N: ____

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: X N: ____

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: X N: ____

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y: X N :____

5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: ____ N: X

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y: ____ N: X

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y: X N:____

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion? Y: X N: ____

9. Does the operator track internal corrosion and take corrective action to prevent recurrence? Y: X N: ____

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
    ____ Gas and Fluid analysis
    ____ Rates of pipeline corrosion as determined by coupons
    ____ Solids removed from the system
    ____ Analysis of inhibitor samples from the pipeline
    X Magnetic and electronic device (pigs)
    X Other

11. Is the inhibitor compatible with the product being transported? Y: X N: ____ N/A: ____

Comments:
The operator has an internal corrosion program and uses hydrogen foils to help with inhibitor injections. Enbridge regularly conducts internal inspections to identify metal loss and to repair these locations.

Attachment 3
Operator Qualification Worksheet

For any item below checked N, an explanation must be included in this report.

The following questions are to be used by the inspector to provide information in determining a need for a more intensive OQ field inspection.

1. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual's performance of a covered task may have contributed to an incident? Y X N _____

2. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual is identified who may no longer be qualified to perform a covered task? Y X N _____

3. Do the individuals performing covered tasks know how to recognize and react to abnormal operating conditions (AOCs) that may be encountered while performing tasks? Y X N _____

4. Are the employee and/or contractor individuals observed performing covered tasks qualified per OQ program requirements? (Documentation may be a hardcopies or database records available at the job site or local office.) Y X N _____

5. Are the individuals who are observed performing covered tasks adhering to operator's procedures? Y X N _____

Comments:

9.6.05

Attendance Sheet

Meeting Description Enbridge Records

Date 9/06/05 **Location** Superior, Wi

	Person Attending	Title	Company	Phone Humber	E-mail Address
1	Joshua Johnson	General Eng	OPS-PHMSA	816-415-9264	joshua.johnson@dot.gov
2	Brian Pierzina	Sr. Engineer	MNOPS	218-327-4218	brian.pierzina@state.mn.us
3	JAY JOHNSON	COMP COORD.	ENBRIDGE	715/394-1512	JAY.JOHNSON@ENBRIDGE.COM
4	STEVE SWENEY	SR. ENG. SPEC	MNOPS	651/296-9639	steve.sweeney@state.mn.us
5	Patsy Bolk	Compliance Analyst	Enbridge	715 394-1504	patsy.bolk@enbridge.com
6	Leisa Doberstein	Compliance Qualification Coordinator	Enbridge	780-420-8788	leisa.doberstein@enbridge.com
7					
8	RANDY WILBERG	SAFETY & COMP COORDINATOR	ENBRIDGE	715-394-1412	RANDY.WILBERG@ENBRIDGE.COM
9	CHUCK PAYMENT	CONT. EMP.	ENBRIDGE	218-428-7847	PAYMENTC@ENBRIDGE.COM
10	MIKE GOMAN	SR. COMP. COORDINATOR	ENBRIDGE	715-394-1523	MIKE.GOMAN@ENBRIDGE.COM
11	Todd Gilseth	Safety	Enbridge	218-759-6615	Todd.Gilseth@Enbridge.com
12	MARK JERABEK	COMMUNICATIONS	ENBRIDGE	715-394-1538	mark.jerabek@enbridge.com
13	John W Bissell	Sr. CP Special	ENB	715-394-1417	john.bissell@enbridge.com
14	MATT J. Wright	CP Specialist	ENB	918-285-1133	Matt.J.Wright@enbridge.com
15	Gordy Jensen	CP Specilist	ENB	715-394-1526	Gordon.Jensen@enbridge.com
16	Kimberly-Joy Harris	Sr CP Specialist	Enbridge	219-922-3133 x236	Kimberly.Harris@Enbridge.com
17	Dan Klavner	Regional Eng.	ENB	715-394-1414	dan.klavner@enbridge.com
18					
19					
20					

Attendance Sheet

Meeting Description Enbridge - Escanaba Unit

Date ________ Location ________

	Person Attending	Title	Company	Phone Number	E-mail Address
1	Joshua Johnson	General Engineer	USDOT-PHMSA	816-329-3825	joshua.johnson@dot.gov
2	JAY JOHNSON	COMP COORD	ENBRIDGE	715/394-1512	jay.johnson@enbridge.com
3	Gregg Harrom	Tech. Supr.	Enbridge	906-789-1221, ext 15	gregg.harrom@enbridge.com
4	Michael Skaggs	Elect. Tech.	Enbridge	231-238-0887	Mike.Skaggs@enbridge.com
5	John Bissell	Sr Cath. Prot. Sp.	ENB	715-394-1417	john.bissell@enbridge.com
6	Gordy Jensen	Cath Prot. Sp	ENB	715-394-1526	Gordon.Jensen@enbridge.com
7	Mike Burnis	Elect. Tech.	ENB	906-477-6722	Mike.Burnis@enbridge.com
8	Tracey Stine	Elect Tech	ENB	(906) 265-3722	tracey.stine@enbridge.com
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge

Date(s): 9/8/05 to 9/9/05

Unit: Superior

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
Superior Terminal						
Line 5 Discharge	24"	-1.301				
Booster Pump		-1.234				
Line 1 Receiver	18"	-1.503				
Line 2 Receiver	22"	-1.530				
Line 3 Receiver	26"	-1.372				
Line 4 Receiver	36"	-1.368				
HVL Relief Tank		-1.488				
Rectifier 1097Q				27.3 V	12.7 Amps	
Tank 2 -East		-1.399				
-North		-1.588				
-West		-1.591				
-South		-2.066				
Rectifier 1097G				7.4V	35.25 Amps	
Tank 8 -East		-1.925				
-North		-2.260				
-West		-2.345				
-South		-1.993				
Tank 4 -East		-2.522				
-North		-2.548				
-West		-2.382				
-South		-2.590				
Tank 30 -East		-1.537				
-North		-1.516				
-West		-1.495				
-South		-1.534				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	Enbridge	**Date(s):**	9/8/05 to 9/9/05
Unit:	Superior		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
Superior Terminal						
Tank 11 -East		1.768				
-North		1.580				
-West		1.528				
-South		1.683				
Rectifier 1097B				7.1 V	29.4 Amp	
Tank 2 -East		-1.543				
-North		-1.605				
-West		-1.585				
-South		-1.670				
Rectifier 1097C				6.9 V	40.1 Amp	
Tank 14 -East		-1.650				
-North		-1.563				
-West		-1.604				
-South		-1.706				
Tank 16 -East		-1.785				
-North		-1.811				
-West		-1.629				
-South		-1.858				
-Center		-1.925				
Tank 27 -East		-1.058				
-North		-1.001				
-West		-1.093				
-South		-1.015				
Rectifier 1097P				17.0 V	14.3 Amp	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge **Date(s):** 9/8/05 to 9/9/05

Unit: Superior

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Rectifier Amps	Remarks
Superior Terminal						
Tank 24 -East		-1.346				
-North		-1.483				
-West		-1.285				
-South		-1.310				
Border to Superior						
Rectifier 1087				10.6 V	5.9 Amp	
MP 1088 Exposed Span	18"	-1.310				
(Line 1)						
Milepost 1088.5 – Line 1	18"	-1.476				
Line 2	22"	-1.494				
Line 3	26"	-1.483				
Line 4	36"	-1.518				
Ino Station						
Suction	24"	-1.465				
Discharge	24"	-1.967				
MP 1135.32 (Rd 244)	24"	-1.698				
MP 1132.6 (Battle Axe Rd)	24"	-1.760				
MP 1127.62 (Muskeg Rd)	24"	-1.574				
Valve						
MP 1122.59 (Co Rd H)	24"	-0.986	-0.590			
MP 1115.5 (Peterson Rd)	24"	-2.302	-0.957	7.9 V	8.4 Amps	
MP 1109.6	24"	-1.395	-0.922			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge

Date(s): 9/19 to 9/23/05

Unit: Escanaba

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
Indian River Station - 1515						
Sump		-3.169				
Discharge Valve		-2.495				
Control Valve		-1.484				
Suction Valve		-1.743				
Rectifier 1515				11.1 V	4.0 Amps	
MP 1541.1 Fairgrieve		-1.844				
MP 1534.9 F44		-1.650				
MP 1526.7 Sturgeon Valley		-1.865	-0.462			
MP 1521.7 Glen Rose Dr		-1.921				
MP 1508.9 Valve		-1334				Valve Operated
MP 1498.8 Rectifier				11.1 V	11.4 Amps	
Valve		-1.640				
MP 1487.79 Hebron Rd		-2.232				
MP 1482.66		-1.852				
MP 1481.23 X-ing with		-2.153 (E)				
GLGT		-2.245 (GL)				
Mackinaw Station						
Station Rectifier				17.15V	4.1 Amps	
Sump		-1.243				
Launcher		-1.346				
Receiver – West Loop		-1.542				
Receiver – East Loop		-1.290				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge

Date(s): 9/19 to 9/23/05

Unit: Escanaba

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
North Straights Station						
Station Rectifier				8.23V	9.27 Amps	
Launcher – East Loop		-1.908				
Launcher – West Loop		-2.039				
Reciever		-2.245				
MP 1471.57 Cheeseman Rd		-2.107				
MP 1465.50 Valve		-1.585				Valve Operated
MP 1460.18		-2.253				
MP 1456.29		-1.712				
MP 1453.22 Valve		-1.897				Valve Operated
MP 1449.98		-2.281	-0.186			
Naubinway Station						
Station Rectifier "A"				36.26 V	4.0 Amps	
Station Rectifier "B"				65.1 V	7.7 Amps	
Discharge Valve		-3.661				
Sump		-2.042				
Suction Valve		-2.436				
MP 1436.34		-2.672				
MP 1425.17		-1.892	-0.276			Old Lakehead sign on one sign
Gould City Station						
Station Rectifier				27.9 V	6.6 Amps	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	Enbridge	**Date(s):**	9/19 to 9/23/05
Unit:	Escanaba		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
Sump		-1.978				
Discharge Valve		-2.563				
Suction Valve		-2.560				
Control Valve		-2.046				
MP 1412 Highway 77		-1.275	-0.701			
MP 1396.39 DS Escanaba Rv		-2.320				
Manistique Station						
Rectifier				48.5 V	2.9 Amps	
Discharge		-3.533				
Suction		-3.662				
Sump		-5.24				
MP 1387.57		-1.806	-0.490			
MP 1382.61		-2.272				
MP 1373.13 Valve		-1.538				Valve Operated
MP 1369.63 Rectifier		-2.655	-0.641	24.22 V	8.8 Amps	
MP 1365.30		-1.409				
MP 1359.22		-2.098				
Rapid River Station						
Station Rectifier				33.2 V	5.7 Amps	
Sump		-1.645				
Suction Valve		-7.20				
Discharge Valve		-6.03				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge | **Date(s):** 9/19 to 9/23/05

Unit: Escanaba

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 1351.52		-0.556	-3.121	16.82 V	6.2 Amps	
MP 1343.74 Downstream Escanaba River Valve		-1.482		27.6 V	2.1 Amps	Valve Operated
MP 1341.41		-1.932				
MP 1334.34 Upstream Escanaba River Valve		-2.001		5.45 V	0.12 Amps	Valve Operated
MP 1329.2		-2.370		25.5 V	0.4 Amps	Former Arnold Pump Station
MP 1325.00		-2.327				
MP 1318.54 Valve		-1.945				Valve Operated
MP 1318.86		-1.842				
MP 1314.34		-4.61	-0.607			
MP 1307.35 Valve		-1.980				Valve Operated
MP 1306.92		-2.421				
MP 1301.69		-2.057	-0.868			
MP 1296.64		-1.578	-0.610			
MP 1289.12		-2.238	-0.387			
MP 1287.02 Rectifier				10.93 V	2.3 Amps	
MP 1280.3		-1.845				
MP 1274.42		-1.737	-0.514			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge **Date(s):** 9/19 to 9/23/05

Unit: Escanaba

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
Iron River Station						
Station Rectifier				48.3 V	7.9 Amps	
Sump		-4.076				
Receiver		-5.04				
Launcher		-3.025				
MP 1265.26		-4.28		40.4 V	7.8 Amps	
MP 1254.3		-2.169				
MP 1247.89 Valve		-1.181				Valve Operated
MP 1239.65		-1.895	-0.348			
MP 1233		-4.77		36.6 V	7.9 Amps	
Geobic Station						
Station Rectifier				55.1 V	15.8 Amps	
Sump		-8.22				
Discharge Valve		-2.424				
Suction Valve		-2.471				
MP 1218.98		-2.282	-2.282	25.7 V	8.8 Amps	Casing is wax filled
MP 1212.18 Valve		-1.231				Valve Operated
MP 1212.06		-1.837				
MP 1205.08 Valve						Valve Operated
MP 1197.04		-1.211				

Activity ID 115066 **RECEIVED NOV 2 1 2005**

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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:	Steve Sweney & Brian Pierzina November 14, 2005	**Inspector/Submit Date:**	October 7, 2005
		Peer Review/Date:	11/15/05
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Enbridge Energy Limited Partnership	**OPID #:**	11169
Name of Unit(s):	Enbridge Pipelines (Lakehead) – Minnesota portion OPID 11169 Federal System 152 CE System 1, OPS Unit 3083	**Unit # (s):**	3083
Records Location:	Superior, WI		MNOPS Case 5488
Unit Type & Commodity:	Hazardous Liquid – Crude Oil and NGL		
Inspection Type:	Field and Records	**Inspection Date(s):**	7/28/05 &9/6-9/05
OPS Representative(s):	Brian Pierzina (7/28/05 & 9/6-9/05) & Steve Sweney (9/6-9/05); Joshua Johnson represented US DOT OPS.	**AFO Days:**	9 (MNOPS only)

Summary:

The inspection consisted of a Field and Records review and Field OQ review for the Enbridge Pipelines (formerly Lakehead) in Minnesota, including the 18, 20, 26, 34, 36, and 48 inch pipelines and associated pumping stations, valves, and other facilities. The records were reviewed at the operator's Superior Office September 6-7, and the field review was conducted September 8-9. MNOPS inspector Steve Sweney conducted the inspection for the ND border to Bemidji, and MNOPS inspector Brian Pierzina did the portion from Bemidji to the Wisconsin border. Central Region inspector Joshua Johnson covered portions of Wisconsin and Michigan. The operator was well prepared, and the personnel were knowledgeable and informative

This is the final report related to our recent Field & Records/OQ9 inspection of Enbridge Energy Company (Lakehead) LLC OPID 11169, Federal System 152 CE System 1, OPS Unit 3083, conducted on July 28 and September 6-9, 2005. The PIM/digital images were sent by email on October 7, 2005; and by U.S. mail on October 11, 2005. Please note that PIM item 195.404(a)(2) was checked as unsatisfactory, but has since been found to be satisfactory, as indicated in this report. No non-compliances were found. MNOPS case 5488 is closed.

Findings:

There were no violations identified as a result of the Field or Records review. Upstream of Clearbrook, consideration was initially given to a possible probable violation of 195.404(a)(2), related to Viking Gas Transmission Company's pipeline crossing at Enbridge MP 813.5. At first, we understood that the Viking crossing was not indicated on an Enbridge alignment sheet, nor on the cathodic protection annual testing printouts for 2002, 2003 or 2004 (but, for the latter, was not required per 195.404(a)(2)). Of late, we have learned that the Viking crossing was indeed listed on the Enbridge "route sheet," aka alignment sheet, at the time of our inspection. We have confirmed that the Viking crossing point with Enbridge (MP 813.5) is indicated on the route sheet for that area. There is no interference bond at the crossing point. A cathodic protection (CP) test station has been added at the crossing point for the 2005 (and future) cathodic protection annual CP surveys, and Enbridge CP test data has been requested from Viking for CP survey years 2002-2004. Emails from Patsy Bolk dated Thursday, October 20 and Monday, November 14, 2005, provided additional documentation related to the Viking crossing, which now satisfies my initial concerns, so the issue is closed

The 2004 Annual Report was initially found to be incorrect concerning pre-1970 ERW pipe, but later judged to be adequate upon further explanation by the operator (see detail below). There was some confusion in compiling the data which is in the process of being corrected. The data available concerning a 5/20/04 leak on Tank #58, in Clearbrook appeared to indicate a non-compliance for telephonic reporting, but the operator later provided information that NRC Report #722365 was provided in compliance with the regulations. A review of public official liaison activities indicated some small volunteer fire departments may not be included in the operator's public awareness program. As a result of additional evaluation, at least six small departments have been added into the company's program. It was recommended that aerial patrol documentation and follow-up include confirmation of One Call information

Findings:

for excavation related activities, and that patrol information be readily presented by Milepost, such that particular areas, and even HCA's, be evaluated for increased activity. The operator was currently working on database modifications that may allow this to be done more easily. Abnormal Operating Conditions are typically initiated at the Edmonton Control Center. Depending on the circumstances, the response to the condition may generate a FACMAN or Maximo record of the response, investigation, and mitigation of the problem. In some examples that were reviewed, it required additional contacts to determine how individual AOC's were resolved.

The Field portion of the inspection began 9/8/05 at Wrenshall, and concluded 9/9/05 at the North Cass Lake pumping station. All facilities appeared to be well maintained. Initial cathodic protection testing provided strange readings, and it was determined the technician's meter had gone bad. We discussed AOC's of cathodic protection testing, and it was agreed that erroneous readings could be expanded within the operator's OQ program to instruct personnel on the recognition of erroneous readings, and provide guidance related to the proper course of action, for situations like high levels of telluric current activity. At the Deer River pumping station, there were two AOC's on-going at the time of the inspection. The Unit 2 discharge valve for Line 2 locked out on a fail to open signal. The technicians tested the valve, and then conducted a second test to confirm the valve was properly finctioning. On Line 4, Unit #1 locked out on high current draw. We observed the technician test the motor and wire insulation, and visually inspect the panel and wires at the motor. These OQ activities, as well as valve maintenance, CP testing, rectifier inspection, bond inspection, and pressure sensor testing were evaluated as part of the Field OQ review.

9-29-05, SMS: The following documentation covers inspection activity related to Federal Inspection Unit 3803 (OPID 11169, Federal System 152 CE System 1; MNOPS Inspection Unit 153163). The office portion of the F&R inspection was conducted in Superior, Wisconsin, on September 6-7, 2005. The field portion of the inspection was conducted from a point near the Red River (North Dakota border) to Bemidji, Minnesota, on September 8-9, 2005. Participating Enbridge personnel in the office portion: Patsy Bolk, Compliance Analyst; Leisa Doberstein, Compliance Qualification Coordinator; Todd Gilseth, Safety Training & Compliance Analyst; Mike Goman, Senior Compliance Coordinator; Kimberly Harris, Senior CP Specialist; Jay Johnson, Compliance Coordinator; Randy Wilberg, Safety Training & Compliance Coordinator; Josh Johnson, Federal OPS General Engineer; Brian Pierzina, MNOPS, and others (see sign-in sheet in hard file for office portion). Participating Enbridge personnel in the field portion: Patsy Bolk, Compliance Analyst; Todd Gilseth, Safety Training & Compliance Analyst; Kimberly Harris, Senior Cathodic Protection (CP) Specialist (who indicated that all of the pipelines are electrically continuous and who performed all of the CP testing using Enbridge equipment, with all rectifiers 'on' except where noted); and Blake Olson, Clearbrook Terminal Supervisor. The field portion began at 9:00 AM on September 8, near the east side of the Red River/ND border, at mainline valves at MP 805 where cathodic protection (CP) was -1.150v. There are five pipelines between this point and the Clearbrook Terminal. They are Line 1-20" HVL, Line 2-26", Line 3-34"&36", Line 4-48"&36", and Line 13-18". Our three vehicle caravan criss-crossed the pipeline on gravel roads over much the westerly extent of their pipeline system, where above-ground conditions including the presence of line markers were observed. At MP 811.5, a line marker at County Road 23 (220th Street) was observed to have been knocked down, probably by agricultural equipment getting too close from the adjacent farm field. Enbridge's Todd Gilseth followed-up immediately, and indicated on 9-9-05 that the subject line marker had been replaced. At the Donaldson Pump Station at MP 814, CP was -1.271v on the Line 4 discharge pressure take-off line. Viking Gas Transmission Company's pipeline crossing at Enbridge MP 812.7 was not observed to be indicated on Enbridge alignment sheets, nor on the cathodic protection printouts for 2002, 2003 or 2004. ("Viking 04" was observed on a Viking marker post located several hundred feet to the north of the crossing point, which is in a farm field). Initially, we believed that this could be a probable violation of 195.404(a)(2) and expected further explanation and response from Patsy Bolk. We understood that the Viking crossing was not indicated on an Enbridge alignment sheet; nor on the cathodic protection annual testing printouts for 2002, 2003 or 2004 (but, for the latter, was not required per 195.404(a)(2)). Of late, we have learned that the Viking crossing was indeed listed on the Enbridge "route sheet," aka alignment sheet, at the time of our inspection. We have confirmed that the Viking crossing point with Enbridge (MP 813.5) is indicated on the route sheet for that area. There is no interference bond at the crossing point. A cathodic protection (CP) test station has been added at the crossing point for the 2005 (and future) cathodic protection annual CP surveys, and Enbridge CP test data has been requested from Viking for CP survey years 2002-2004. (Emails from Patsy Bolk dated Thursday, October 20 and Monday, November 14, 2005, provided additional documentation related to the Viking crossing, which now satisfies my initial concerns, so the issue is closed). We stopped at a rectifier at MP 840.8 where CP was -1.428v on the 48" MLV, and -1.472v on the 34" MLV (Line 3). At the Viking Pump Station (MP 848), CP was -1.875v on the Line 1 pump piping. At the Plummer Pump Station (MP 877), I spent time observing gas sensors and heat detectors, and spoke with Rick Kimball and Rick Matilla on local abnormal operating condition recognition as part of an OQ evaluation per Attachment 3, Operator Qualification Worksheet, of the OPS Form 3. We spent some time discussing rectifier safety upon first touching a rectifier box with intent of opening the box and making observations, including checking the voltage and amperage outputs. Enbridge indicated an intent to provide these workers with shirt-pocket voltage detector probes (light sticks) to detect any direct shorts of electrical current to the boxes prior to touching with the human hand (such would be a practical personal safety matter, and would not be an OQ requirement). At the time of my visit, lines 1, 3 and 4 were running, while lines 2 and 13 were out-of-service. I also checked several fire extinguishers, including a larger wheeled fire extinguisher (last checked 9-6-05), and found no probable violation. CP at Line 1 (20") was -1.670v. On the west side of the Red Lake River (MP 864), the rectifier was reading 11.7 volts and 9.3 amperes. CP on Line 4 was

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Findings:

-1.674v. Line 4 has a hydrogen foil at this location, for which I requested a history of the data for further consideration and evaluation; expect further explanation and response from Patsy Bolk. On the east side of the Red Lake River (MP 865), CP on Line 3 (34") was -1.361v. At MP 864.5, there is a thirty foot wide (at the top) county ditch where the 18", 26"' and 34" pipelines are exposed in their entirety to the atmosphere (see digital images). The 18" pipeline "looked shallow" (installed in 1949), so I used my tape measure to estimate 24" of cover where the pipeline intersects the near edge of the agricultural field to the east. Todd Gilseth checked further and learned that the subject line had been probed in that area and was found to be 28" or more deep. This area will be considered for future line lowering to acquire additional depth over the 18" line. The other two pipelines were observed be deeper at the ditch crossing. At MP 896 near Trail, Minnesota, the rectifier was reading 14.1 volts and 6.3 amperes. CP on Line 2 (26") was -1.824v. At the Clearbrook Terminal (MP 909), I met terminal supervisor Blake Olson, and electrical technician Sam Sparhawk, and others. We spent time in Blake Olson's office learning about the terminal and current activities. I learned that recent floor scans have not included Tank 59, which has perimeter anodes, but no under-tank anodes or under-tank reference electrode capability. Kimberly Harris indicated an intent to work with local corrosion technician John Bissell to propose next action for Tank 59 in 2006, such as a floor scan or under-tank anode and reference cell placement to further promote the integrity of the tank floor. Tank 60 had just undergone floor remediation, but the D doors were still off, so we went inside and had a quick look around before a thunderstorm drifted over and we evacuated the tank. While inside the tank, I observed the new floor surface and walked around, looking at the bottom of the floating roof, roof legs, and the primary seal at the inside surface of the tank wall. On our way out of the terminal, we drove by Tank 59, where Kimberly Harris determined that CP was perimeter anodes only, and not under-tank anodes with permanent reference electrode capability. The following is a matrix that depicts perimeter versus under-tank grid anodes, and an indication of recent floor scans.

Tank	Perimeter	Under-tank Grid	Floor Scan
56	x		x
57	x		x
58	x		x
59	x		
60	x		x
61		x	
62		x	x
63		x	
64		x	

At the Wilton Pump Station (MP 929), the rectifier was reading 11.0 volts and 5.1 amperes. On piping inside the station, CP was-2.6v, obviously in the influence of the nearby distributed anode bed. At this location, only the rectifier located in the station wa cycled on and off for the purpose of making an evaluation of voltage drop in the area. I drove with Kimberly Harris to MP 928 where we observed an 'on' reading of-1.962v and an 'off' reading of-1.505v, while the Wilton rectifier was manually cycled. It should be noted that no other company or foreign rectifiers were cycled, and therefore, the 'off' reading was likely influenced by other current sources. This was the only place where a rectifier was cycled during this inspection west of Bemidji. Thefield portion was concluded at the Bemidji Office where we searched for but could not find pretested 34" emergency stock pipe as follows from records for Bemidji that I viewed while in Superior, Wisconsin: 'Stock pipe, 34", 0.344" wall, X52, 2 joints, 80' approximately, Berg Steel Pipe Corporation, DSAW, 1052 minimum test pressure, 3-7-00, test report no.: 999-00-04, water, 39'-8", 39-1".' There were many sticks of pre-tested stock pipe of varying diameters evident at the Bemidji Office yard; just not thesticks for which I was searching. Patsy Bolk called me after the inspection and said the subject pretested pipe was found to exist in their Griffith, Indiana, pipeline maintenance facility, and that the record I viewed (requested her to fax a copy to me) made no mention of the referenced stock pipe actually being located in Bemidji.

10-5-05, SMS: At the current time, I am awaiting from Patsy Bolk, 1. an email with a written explanation of the Bemidji stock pipe issue (Note: An email from Patsy Bolk dated Friday, October 14, 2005, provided additional documentation of the stock pipe issue, which now satisfies my initial concerns, so the issue is closed); 2. emails with a written explanation of the "missing" Viking Gas Transmission Company pipeline crossing information(which were received on October 20 and November 14, 2005, which verified further that the Viking crossing had been missing on the annual CP testing reports for 2002, 2003, 2004(but was not required per 195.404(a)(2)), and was demonstrated on November 14, 2005, to have existed on the route sheet, aka alignment sheet, at the time of the inspection); 3. an email with beta foil history for Line 4 at MP 864 (west side of Red Lake River MLV) (Note: An email from Patsy Bolk dated Friday, October 14, 2005, provided additional documentation of the beta foil history, which now satisfies my initial concerns, so the issue is closed); 4. an email with 'Tank 58 post-accident review' documentation for the release due to a floor crack on 5-20-04 resulting in $50,000 in clean-up and repairs (Note: An email from Mike Goman dated Tuesday, September 13, 2005, provided additional documentation of the post accident review, which now satisfies my initial concerns, so the issue is closed); 5. an email with further explanation of intent regarding the2004 annual report to DOT (dated June, 2005) which might

Findings:
have contained inaccuracies with regard to ERW data (Note: An email from Patsy Bolk dated October 14, 2005, provided additional documentation of the reporting concern, which now satisfies my initial concerns, so the issue is closed); 6. an email that addresses non-destructive testing of up to five welds associated with the Viking Station pipe replacement effort in July of 2004 to replace old 34" fittings and dead leg(s) (Note: An email from Mike Goman dated Tuesday, September 13, 2005, provided an additional sketch and radiographic examination reports, which now satisfies my initial concerns about item 6., so the issue is closed); and 7. an email that addresses Kimberly Harris' stated intent to work with local corrosion technician John Bissell to propose next action(s) for Tank 59 in 2006, such as a floor scan or under-tank anode and reference cell placement to further promote the integrity of the tank floor. (Note: An email from Patsy Bolk dated Thursday, October 20, 2005, provided additional documentation of the plans to address Tank 59 which now satisfies my initial concerns, so the issue is closed).

Name of Operator: Enbridge Energy, Limited Partnership	
OP ID No. [1] 11169	**Unit ID No.** [1] 3083
H.Q. Address:	**System/Unit Name & Address:** [1]
1100 Louisiana Street Suite 3300 Houston, TX 77002-5217	Enbridge Pipelines (Lakehead) L.L.C. 119 N. 25th Street East Superior, WI 54880
Co. Official: Dan C. Tutcher	**Activity Record ID#:**
Phone No.: 713-650-8900	**Phone No.:** 715-394-1400
Fax No.: 713-653-6711	**Fax No.:** 715-394-1500
Emergency Phone No.: 800-858-5253	**Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Mark Willoughby	Manager, Compliance	715-394-1534
Mike Goman	Senior Compliance Coordinator	715-394-1523
Jay Johnson	Compliance Coordinator	715-394-1512
Patsy Bolk	Compliance Analyst	715-394-1504
Leisa Doberstein	Compliance Qualification Coordinator	800-379-4781 (ext. 8788)

OPS Representative(s) [1] Joshua Johnson **Inspection Date(s)** [1] S eptember 6-9, 2005

Company System Maps (copies for Region Files): previously provided

Unit Description:

[1] Information not required if included on page 1.

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This unit consists of the former Lakehead Pipeline in Minnesota, beginning at the North Dakota border, and concluding at the Wisconsin border. It includes 18, 20, 26, 34, 36, and 48 inch pipelines primarily transporting crude oil as well as NGL in the 18/20 inch pipeline. It includes a tank farm at Clearbrook, MN, receipt from Enbridge North Dakota (formerly Portal) and delivery to Minnesota Pipeline at Clearbrook. There are numerous pumping stations along the pipeline route, including Donaldson, Viking, Plummer, Clearbrook, Wilton, Cass Lake, Deer River, Blackberry, Floodwood, and Gowan.

Portion of Unit Inspected [1]

The inspection consisted of record review at the Superior Office, and field review of pumping stations and other facilities along the pipeline ROW.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections. If the inspection is in the OPS Joint O&M inspection 5 year period, procedures necessitated by new or amended regulations placed in force after the Joint Team O&M Inspection, and those known to have changed since the Joint Team Inspection, should be reviewed. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 2/25/00 and 2/25/05.

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Unless otherwise noted, all code references are to 49CFR Part 195. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	CONVERSION TO SERVICE	S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				X

Comments:
This item was Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
*	.49	NLT June 15, 2005, operator must complete Annual Report and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Amdt 195-80 pub. 1/06/04, eff. 2/05/04.				X
* .402(a) .402(c) (2)	.50	Accident report criteria, as detailed under 195.50. In general, **5 gallons** or more, **death or personal injury necessitating hospitalization**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. Note: A release of less than 5 gals may still require reporting. See (195.50(b) and 195.52(a)(4)). Amdt 195-75 pub. 1/08/02, eff. 2/07/02				X
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				X
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				X
	.54(b)	Supplemental report - required within 30 days of information change/addition				X
	.55	Safety-related conditions (SRC) - criteria				X
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				X
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				X

Comments:
This item was Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by ' 195.422 and ' 195.200.						
*		Welding must be performed by qualified welders using qualified welding procedures.				X
.402(c)/ .422	.214(a)	Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? Amdt. 195-81 pub. 6/14/04, eff. 7/14/04.				X

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SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
		Welding procedures must be qualified by destructive testing.				X
	.214(b)	Each welding procedure must be recorded in detail including results of qualifying tests.				X
*	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104 (19th Ed., 1999)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2001 Ed.)**, except that a welder qualified under an earlier edition than listed in ' **195.3** may weld, but may not requalify under that earlier edition. Amdt 195-81 pub. 6/14/04, eff. 7/14/04.; Amdt 192-81 corr. Pub. 9/09/04.				X
*	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
Alert Notice 3/13/87		In the welding of repair sleeves and fittings, do the operator's procedures give consideration to the use of low hydrogen welding rods, cooling rate of the weld, metallurgy of the materials being welded (weldability carbon equivalent) and proper support of the pipe in the ditch?				
.402(c)/ .422	**.226(a)**	Arc burns must be repaired.				X
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				X
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				X
	Nondestructive Testing Procedures					
*	**.228 /.234**	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **Section 9 of API 1104 (19th)** and as per ' **195.228(b)** and per the requirements of ' **195.234** in regard to the number of welds to be tested? Amdt 195-81 pub. 6/14/04, eff. 7/14/04.				X
	.234(b)	Nondestructive testing of welds must be performed:				X
		1. In accordance with written procedures for **NDT**				X
		2. By qualified personnel				X
		3. By a process that will indicate any defects that may affect the integrity of the weld				X
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				X
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable (Section 6 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	**.302(a)**	Each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be pressure tested.				X
	.302(b)	Except for lines converted under ' **195.5**, certain lines listed under this section may be operated without having been pressure tested per Subpart E.				X
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in ' 195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				X

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		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				X
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines)				X
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				X
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				X
	.303	Procedures for the risk based alternative to pressure testing?				X
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				X
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with **' 195.302**.				X
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				X
	.306	Appropriate test medium				X
	.308	Pipe associated with tie-ins must be pressure tested.				X
	.310(a)	Test records must be retained for useful life of the facility.				X
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				X
	.310(b)(2)	Test instrument calibration data.				X
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				X
	.310(b)(4)	Date and time of the test.				X
	.310(b)(5)	Minimum test pressure.				X
	.310(b)(6)	Test medium.				X
	.310(b)(7)	Description of the facility tested and the test apparatus.				X
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				X
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				X
*	**.310(b)(10)**	Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C

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			SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.402	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				X
		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				X
		c.	Appropriate parts must be kept at locations where O&M activities are conducted.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		MAINTENANCE & NORMAL OPERATION PROCEDURES	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				X
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				X
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				X
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **' 195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				X
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **' 195.406**?				X
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **' 195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				X
	.402(c) (10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				X
*		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per ' 195.59. Amdt 195-69 pub. 9/8/00, eff. 10/10/00.				X
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				X
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				X
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				X
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				X
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				X
		iii. Loss of communications?				X
		iv. The operation of any safety device?				X
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				X
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				X
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				X
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				X
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				X

Comments:

These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

EMERGENCY PROCEDURES			S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				X
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				X
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				X
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				X
	.402(e)(5)	Controlling the release of liquid at the failure site?				X
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				X
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				X
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				X
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				X

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under ' 195.402.				X
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				X
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				X
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				X
*	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				X
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				X
	.403(b)(2)	Make appropriate changes to the emergency response training program				X
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

MAPS and RECORDS PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				X
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				X
		ii. Pump stations				X
		iii. Scraper and sphere facilities				X
		iv. Pipeline valves				X
		v. Facilities to which ' **195.402(c)(9)** applies				X
		vi. Rights-of-way				X
		vii. Safety devices to which ' **195.428** applies				X
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.	X			

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		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
	.404(a)(3)	The maximum operating pressure of each pipeline.				X
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				X
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				X
	.404(b)(1)	The discharge pressure at each pump station.				X
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under ' **195.402** apply.				X
	.404(c)	Each operator shall maintain the following records for the periods specified:				X
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				X
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				X
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously. However, 195.404(a)(2) was checked for the Viking Gas crossing at MP 812.7, where the crossin g had not been noted on the alignment sheets used during the field audit, nor on the cathodic protection annual testing documentation for 2002, 2003, and 2004. Separate violation report to follow.

		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by ' **195.106**.				X
	.406(a)(2)	The design pressure of any other component on the pipeline.				X
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				X
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				X
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				X
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				X
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				X
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				

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		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
	.408(b)(1)	Monitoring operational data as required by ' 195.402(c)(9).				X
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				X
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				X
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		LINE MARKER PROCEDURES	S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				X
	.410(a)(2)	Must have the correct characteristics and information				X
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				X
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years.**				X

Comments:
The se items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES	S	U	N/A	N/C
* .402(a)	.413(a)	Procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) that are at risk of being an exposed underwater pipeline or a hazard to navigation. Gathering lines of 4 ½ inches (114mm) nominal outside diameter or smaller are exempt. (Procedures must be in effect August 10, 2005.) Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(b)	Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				

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		UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES	S	U	N/A	N/C
*	.413(c)(1)	Promptly, but no later than 24 hours after discovery, notify the NRC by phone.				X
*	.413(c)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
*	.413(c)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation. Amdt 195-82 pub. 8/10/04, eff. 9/09/04.				X
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		VALVE MAINTENANCE PROCEDURES	S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times.				X
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **72 months**, but at least **twice** each calendar year.				X
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				X
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				X
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				

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		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(b)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				X
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				X
	.424(c)(2)	Have procedures under ' **195.402** containing precautions to protect the public.				X
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				X
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				X
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				X
		2. **HVL** pipelines at intervals not to exceed **72 months**, but at least **twice** each calendar year.				X
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.				X
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (' 195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				X
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				X

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				X
		The equipment must be:				
		a. In proper operating condition at all times.				X
		b. Plainly marked so that its identity as firefighting equipment is clear.				X
		c. Located so that it is easily accessible during a fire.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**;				X
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 4 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **' 195.402(c)(3).** -Owner/operator visual, external condition inspection interval n.t.e. one month. -External inspection, visual, by an Authorized Inspector at least every five years or at the quarter corrosion rate life of the shell, which ever is less. -External ultrasonic thickness measurement of the shell based on the corrosion rate. If the corrosion rate is not known, the maximum interval shall be five years				X
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.**				X
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier. -Based on thickness of the tank bottom and the corrosion rate but n.t.e. 20 years.				X
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

SIGN PROCEDURES			S	U	N/A	N/C
* .402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				X
		Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03.				X

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Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

SECURITY of FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				X

Comments:
This item was Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

SMOKING OR OPEN FLAME PROCEDURES			S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				X

Comments:
This item was Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

PUBLIC EDUCATION PROCEDURES			S	U	N/A	N/C
.402(a)	.440	Is there a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				X
		Is the program conducted in English and other languages where appropriate?				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

DAMAGE PREVENTION PROGRAM PROCEDURES			S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				X
	.442(b)	Does the operator participate in a qualified One-Call program?				X
	.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				X
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				X
		ii. How to learn the location of underground pipelines before excavation activities are begun.				X
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				X

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		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				X
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				X
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				X
		ii. In the case of blasting, any inspection must include leakage surveys.				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator=s procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				X

Comments:
This item was Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

	PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES	S	U	N/A	N/C
.452	This form does not cover Liquid Pipeline Integrity Management Programs				

	SUBPART G - OPERATOR QUALIFICATION PROCEDURES	S	U	N/A	N/C
.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				X

*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.				X
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				
		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.				X
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				X
		2) Is a segment that is relocated, replaced, or substantially altered?				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				X
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				X
		b. All coating damage discovered must be repaired.				X
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				X
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				X
		2) Is a segment that is relocated, replaced, or substantially altered.				X
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				X
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				X
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				X
	.567	Test leads installation and maintenance.				X
	.569	Examination of Exposed Portions of Buried Pipelines.				X
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-96** (incorporated by reference).				X
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**.				X
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.				X
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-96.**				X
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				X
		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment				X
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.**				X
		Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months**				X
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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*		SUBPART H - CORROSION CONTROL PROCEDURES (Amdt 195-73 pub. 12/27/01, eff. 1/28/02)	S	U	N/A	N/C
		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)				X
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				X
	.575	Are there adequate provisions for electrical isolations?				X
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. b. Design & install CP systems to minimize effects on adjacent metallic structures.				X
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken.				X
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion.				X
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 2 months.**				X
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				X
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement).				X
	.583	Atmospheric corrosion monitoring				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				X
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				X
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				X
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				X
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)** ?				X
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**).				X

Comments:
These items were Not Checked because the focus of the inspection was Field and Records, and a Headquarters O&M inspection had been conducted previously.

Alert Notices:
What process does the Operator have to address Alert Notices?

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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Comments:
Recent Alert Notices were discussed. They are typically reviewed by numerous personnel for applicability and evaluation.

Recent Pipeline Safety Advisory Bulletin
ADB-04-03 in August 18, 2004 Federal Register, pp. 51348-51349 (Ref. **fr18au04N Pipeline Safety: Unauthorized Excavations and the Installation of Third-Party Data Acquisition Devices on Underground Pipeline Facilities)**
Reference http://www.gpoaccess.gov/fr/advanced.html

Best Practice: Stress Corrosion Cracking
Pipeline Safety Advisory Bulletin ADB-03-05 in October 8, 2003 Federal Register, pp. 58166-58168 (Ref. **fr08oc03N Pipeline Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Liquid Pipelines**).
Reference http://www.gpoaccess.gov/fr/advanced.html

Is the operator aware of the SCC bulletin, and is the operator reviewing their system for the potential of SCC? Y/N Y

PART 195 - FIELD REVIEW		S	U	N/A	N/C
.262	Pumping Stations	X			
.262	Station Safety Devices	X			
.308	Pre-pressure Testing Pipe - Marking and Inventory	X			
.403	Supervisor Knowledge of Emergency Response Procedures	X			
.410	Right-of-Way Markers	X			
.412	River Crossings	X			
.420	Valve Maintenance	X			
.420	Valve Protection from Unauthorized Operation and Vandalism	X			
.426	Scraper and Sphere Facilities and Launchers	X			
.428	Pressure Limiting Devices	X			
.428	Relief Valves - Location - Pressure Settings - Maintenance	X			
.428	Pressure Controllers	X			
.430	Fire Fighting Equipment	X			
.432	Breakout Tanks				X
.434	Signs - Pumping Stations - Breakout Tanks	X			
.436	Security - Pumping Stations - Breakout Tanks	X			
.438	No Smoking Signs	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.501-.509	Operator Qualification Questions, Observations - See Attachment 3	X			
.571	Cathodic Protection (test station readings, other locations to ensure adequate CP levels)	X			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	X			
.583	Exposed pipeline components (splash zones, water spans, soil/air interface, thermal insulation, disbanded coatings, supports, deck penetrations, etc.)	X			

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION TO SERVICE				
.5(a)(2)	All aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.			X	
.5(c)	Pipeline Records (Life of System)			X	
	Pipeline Investigations			X	
	Pipeline Testing			X	
	Pipeline Repairs			X	
	Pipeline Replacements			X	
	Pipeline Alterations			X	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	X			
.52	Telephonic Reports to NRC (800-424-8802)	X			
.54(a)	Written Accident Reports (DOT Form 7000-1)	X			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	X			
.56	Safety Related Conditions	X			
.57	Offshore Pipeline Condition Reports			X	
.59	Abandoned Underwater Facility Reports			X	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	X			
.214(b)	Test Results to Qualify Welding Procedures	X			
.222	Welder Qualification	X			
.234(b)	Nondestructive Technician Qualification	X			
.589	Cathodic Protection	X			
.266	Construction Records	X			

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
.266(a)	Total Number of Girth Welds	X			
	Number of Welds Inspected by NDT	X			
	Number of Welds Rejected	X			
	Disposition of each Weld Rejected	X			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	X			
.266(c)	Location of each Crossing with another Pipeline	X			
.266(d)	Location of each buried Utility Crossing	X			
.266(e)	Location of Overhead Crossings	X			
.266(f)	Location of each Valve and Test Station	X			
	PRESSURE TESTING				
.310	Pipeline Test Record	X			
.305(b)	Manufacturer Testing of Components	X			
.308	Records of Pre-tested Pipe	X			
	OPERATION & MAINTENANCE				
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	X			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	X			
.402(c)(10)	Abandonment of Facilities			X	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	X			
.402(c)(13)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.402(d)(1)	Response to Abnormal Pipeline Operations	X			
.402(d)(5)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.402(e)(1)	Notices which require immediate response	X			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	X			
.402(e)(9)	Post Accident Reviews	X			
.403(a)	Emergency Response Personnel Training Program	X			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	X			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	X			
.404(a)(1)	Maps or Records of Pipeline System	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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	PART 195 - RECORDS REVIEW	**S**	**U**	**N/A**	**N/C**
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	X			
.404(a)(3)	MOP of each Pipeline	X			
.404(a)(4)	Pipeline Specifications	X			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	X			
.404(b)(2)	Abnormal Operations (' 195.402) (maintain for at least 3yrs)	X			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	X			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	X			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.408(b)(2)	Filing and disposition of notices of abnormal or emergency conditions.	X			
.412(a)	Inspection of the ROW	X			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	X			
.413(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.420(b)	Inspection of Mainline Valves	X			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)	X			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			X	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-HVL; **2 per yr/72 months** HVL)			X	
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).			X	
.440	Public Education	X			
	DAMAGE PREVENTION PROGRAM				
.442(c)(1)	List of Current Excavators	X			
.442(c)(2)	Notification of Public/Excavators	X			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	X			
	CORROSION CONTROL				
.589(c)/.567	Test Lead Maintenance, frequent enough intervals	X			
.589(c)/.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.589(c)/.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/15 months**)	X			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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PART 195 - RECORDS REVIEW		S	U	N/A	N/C
.589(c)/.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)				X
.589(c)/.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas **(1 per 3 cal yr/39 months)**			X	
.589(c)/.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.589(c)/.573(d)	External Corrosion Control - Bottom of Breakout Tanks			X	
.589(c)/.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.589(c)/.575	Electrical isolation inspection and testing	X			
.589(c)/.577	Testing for Interference Currents	X			
.589(c)/.579(a)	Corrosive effect investigation	X			
.589(c)/.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment **(2 per yr/7½ months)**	X			
.589(c)/.579(c)	Inspection of Removed Pipe for Internal Corrosion	X			
.589(c)/.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**	X			
.589(c)/.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG	X			
.589(c)/.585(b)	Localized Corrosion Pitting – replace, repair, reduce MOP	X			
.589(a)&(b)	Cathodic Protection (Maps showing anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:
Items marked "N/A" did not apply to the operator's facilities in Minnesota. Items marked "N/C" were not checked as a part of this inspection. There were No Violations identified as a result of the Field or Records review for the inspection units downstream of Clearbrook. There was considerable discussion on areas where improvements could be made, such as patrol documentation and record-keeping, AOC data processing, and reporting.

The Annual Report was incorrect concerning pre-1970 ERW pipe. There was some confusion in compiling the data which is in the process of being corrected. The data available concerning a 5/20/04 leak on Tank #58, in Clearbrook appeared to indicate a non-compliance for telephonic reporting, but the operator later provided information that a NRC Report #722365 was provided in compliance with the regulations. A review of public official liaison activities indicated some small volunteer fire departments may not be included in the operator's public awareness program. As a result of additional evaluation, at least six small departments have been added into the company's program. It was recommended that aerial patrol documentation and follow-up include confirmation of One Call information for excavation related activities, and that patrol information be readily presented by Milepost, such that particular areas, and even HCA's, be evaluated for increased activity. The operator was currently working on database modifications that may allow this to be done more easily. Abnormal Operating Conditions are typically initiated at the Edmonton Control Center. Depending on the circumstances, the response to the condition may generate a FACMAN or Maximo record of the response, investigation, and mitigation of the problem. In some examples that were reviewed, it required additional contacts to determine how individual AOC's were resolved.

The Field portion of the inspection began 9/8/05 at Wrenshall, and concluded 9/9/05 at the North Cass Lake pumping station. All facilities appeared to be well maintained. Initial cathodic protection testing provided strange readings, and it was determined the technician's meter had gone bad. We discussed AOC's of cathodic protection testing, and it was agreed that erroneous readings could be expanded within the operator's program to instruct personnel on the recognition of erroneous readings, and provide guidance related to the proper course of action, for situations like high levels of telluric current activity. At the Deer River pumping station, there were two AOC's on-going at the time of the inspection. The Unit 2 discharge valve for Line 2 locked out on a fail to open signal. The technicians tested the valve, and then conducted a second test to confirm the valve was properly functioning. On Line 4, Unit #1 locked out on high current draw. We observed the technician test the motor and wire insulation, and visually inspect the panel and wires at the motor.

Comments:

These OQ activities, as well as valve maintenance, CP testing, rectifier inspection, bond inspection, and pressure sensor testing were evaluated as part of the Field OQ review.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]			
194.111	RSPA Tracking Number: Approval Date:			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]			
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			
194.107	Are there complete records of the operator=s oil spill exercise program? [OPA-4]			
194.117	Does the operator maintain records for spill response training (including HAZWOPER training)? [OPA-5]			

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:
This item was not reviewed as a part of this inspection.

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the Asequence number.@ It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP=s state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO=s) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator=s exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator=s personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA=s Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1
SCADA Liquid Worksheet

If an item is found to be unsatisfactory, an explanation must be included in this report.

The topics on this worksheet regard general SCADA functionality. A more thorough SCADA evaluation may be warranted based on the results of this worksheet or prompts by other events.

1. Pipeline Safety Advisory Bulletins (reference http://www.gpoaccess.gov/fr/advanced.html)

Review the following with the operator:

$ Advisory Bulletin ADB-99-03 in July 16,1999 Federal Register p.38501 (Ref.**fr16jy99N Potential Service Interruptions in Supervisory Control and Data Acquisition Systems**) - discuss SCADA system performance.

$ Advisory Bulletin ADB-03-09 in December 23, 2003 Federal Register, pp. 74289-74290 (Ref. **fr23de03N Pipeline Safety: Potential Service Disruptions in Supervisory Control and Data Acquisition Systems**) B discuss consideration of possible SCADA system disruptions caused by system maintenance or upgrade.

Comments:
The SCADA system was not reviewed as a part of this inspection, although numerous discussions concerning Control Center Operations and Abnormal Operating Conditions, and tracking of these fundions did take place.

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. 195.402(d)(1)(iii) - Loss of communications.

$ Off-site Back-up Center
$ Data transfer to redundant or off-site processors
$ Battery and/or Emergency Generator
$ Redundant data communications paths, automatic restoration or manual?
$ Data Reduction & Archiving
$ Indication of stale, forced or manually overridden data, or system lock-up
$ Operating practices during data communications outages

Comments:
This item was not reviewed as a part of this inspection.

3. ' 195.404 - Pump station discharge pressure records.

$ Discharge Pressure records in SCADA or at field locations?
$ Data Reduction & Archiving
$ Data acquisition frequency

Comments:
This item was not specifically reviewed as a part of this inspection.

4. ' 195.404 Maps and records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:
(1) Location and identification of the following pipeline facilities:
(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;

If an item is found to be unsatisfactory, an explanation must be included in this report.

(v) Facilities to which ' 195.402(c) (9) applies;

(vii) Safety devices to which ' 195.428 applies.

(b)(2) Any emergency or abnormal operation to which the procedures under ' 195.402 apply.

$ Ensure SCADA screens/status board are updated to reflect current pipeline configurations.
$ Ensure pipeline safety parameters are current (i.e., MOP, alarm set points, etc.)
$ Review any emergency or abnormal operating condition or schedule deviation records generated by the SCADA system (alarm logs, trending data, etc.). Compare abnormal operating conditions noted in the SCADA data with the operator=s report and reporting procedures as related to those abnormal operating conditions.
$ Data Reduction & Archiving
$ Data acquisition frequency

Comments:
This item was not reviewed as a part of this inspection.

5. ' 195.408 - Communications.

(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system
(b)(1) Monitoring operational data as required by ' 195.402(c)(9)
$ Status Monitoring
$ Alarm Thresholds
$ Alarm Management
$ Event Log
$ Over-short Reports
$ Maintaining pressures within limits described in **' 195.406 Maximum Operating Pressure**

Comments:
This item was not reviewed as a part of this inspection.

6. ' 195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance
$ Over-Short Reports
$ Must Comply with API 1130 requirements in operating, maintaining, testing, recordkeeping, and dispatcher training.

Comments:
This item was not reviewed as a part of this inspection.

' 195.420 & .428 - Testing of applicable SCADA controlled valves, safety devices, and overfill systems functionality.
$ Frequency of testing
$ Inclusion of SCADA component in the tests

Comments: This item was not reviewed as a part of this inspection.

Attachment 2

Internal Corrosion Worksheet - Liquid Pipelines

If an item is found to be unsatisfactory, an explanation must be included in this report.

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: X N: ____

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: X N: ____

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: X N: ____

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 2 months. Y: X N :____

5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: ____ N: X

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y: ____ N: X

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y: X N:____

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined forevidence of internal corrosion? Y: X N: ____

9. Does the operator track internal corrosion and take corrective action to prevent recurrence? Y: X N: ____

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
    - ____ Gas and Fluid analysis
    - ____ Rates of pipeline corrosion as determined by coupons
    - ____ Solids removed from the system
    - ____ Analysis of inhibitor samples from the pipeline
    - X Magnetic and electronic device (pigs)
    - X Other

11. Is the inhibitor compatible with the product being transported? Y: X N: ____ N/A: ____

Comments:
The operator has an active internal corrosion program on the 26 and 48 inch pipelines in Minnesota. Certain points on the pipelines are monitored using hydrogen foils, and inhibitor injections are scheduled accordingly. The operator regularly conducts internal inspections to identify metal loss, whether interior or exterior. The hydrogen foil data is collected continuously at each site and available on demand through remote access for authorized personnel.

Attachment 3
Operator Qualification Worksheet

For any item below checked N, an explanation must be included in this report.

The following questions are to be used by the inspector to provide information in determining a need for a more intensive OQ field inspection.

1. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual's performance of a covered task may have contributed to an incident? Y X N _____
2. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual is identified who may no longer be qualified to perform a covered task? Y X N _____
3. Do the individuals performing covered tasks know how to recognize and react to abnormal operating conditions (AOCs) that may be encountered while performing tasks? Y X N _____
4. Are the employee and/or contractor individuals observed performing covered tasks qualified per OQ program requirements? (Documentation may be a hardcopies or database records available at the job site or local office.) Y X N _____
5. Are the individuals who are observed performing covered tasks adhering to operator's procedures? Y X N _____

Comments:
Initial cathodic protection testing provided strange readings, and it was determined the technician's meter had gone bad. We discussed AOC's of cathodic protection testing, and it was agreed that erroneous readings could be expanded within the operator's program to instruct personnel on the recognition of erroneous readings, and provide guidance related to the proper course of action, for situations like high levels of telluric current activity. At the Deer River pumping station, there were two AOC's on-going at the time of the inspection. The Unit 2 discharge valve for Line 2 locked out on a fail to open signal. The technicians tested the valve, and then conducted a second test to confirm the valve was properly functioning. On Line 4, Unit #1 locked out on high current draw. We observed the technician test the motor and wire insulation, and visually inspect the panel and wires at the motor. These OQ activities, as well as valve maintenance, CP testing, rectifier inspection, bond inspection, and pressure sensor testing were evaluated as part of the Field OQ review.

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:	August 30, 2005	**Inspector:** Steve Sweney
Peer Review/Date:	8/30/05	**Peer Reviewer:** Charles R. Kenow
Director Approval/Date:		**Director Approval**

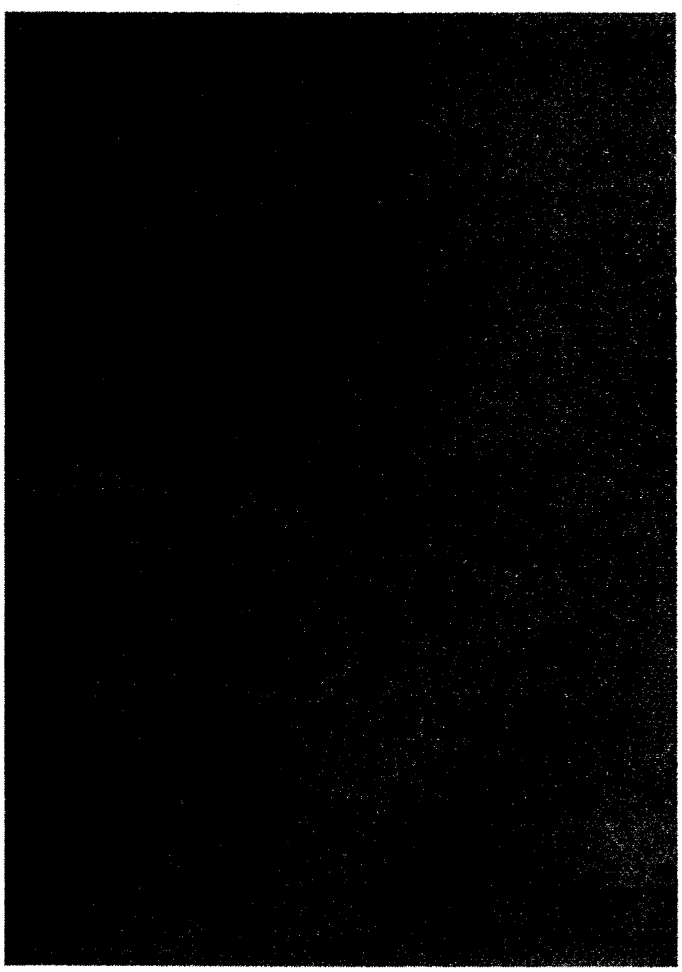
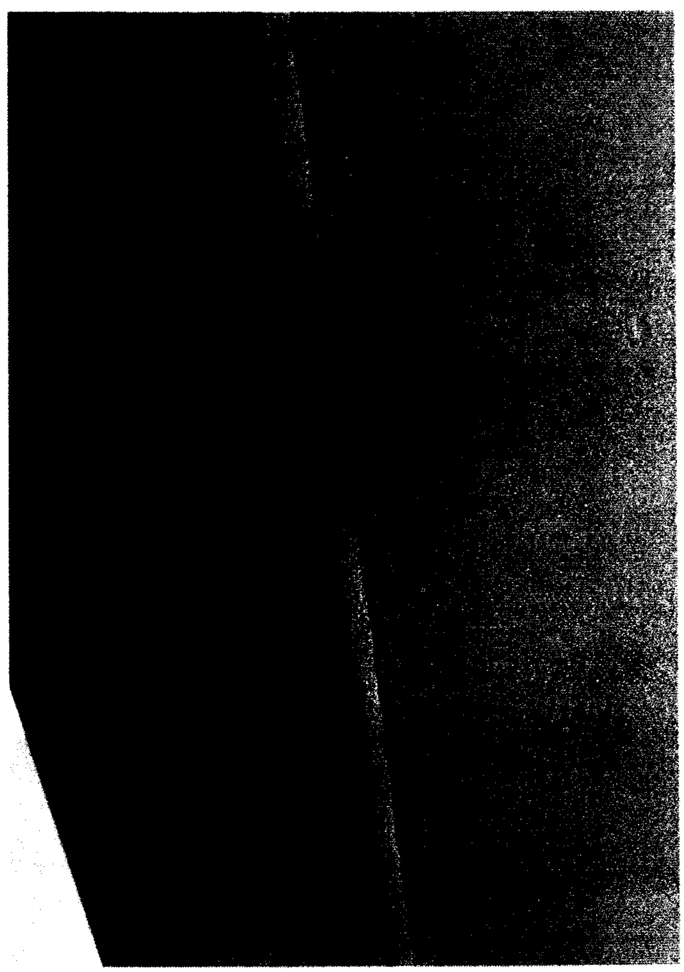
POST INSPECTION MEMORANDUM (PIM)				
Name of Operator:	Enbridge Energy Company, Inc. OPID 11169, Federal System 152 CE System 1, OPS Unit 3803		**OPID #:**	11169
Name of Unit(s):	Deer River - Superior		**Unit #(s):**	3803
Records Location:	119 North 25th Street East			
Unit Type & Commodity:	Hazardous Liquid, Crude Oil			
Inspection Type:	Construction Inspection 450	**Inspection Date(s):**	August 3, 2005	
For OPS :			**AFO Days:**	
For MNOPS :	Steve Sweney (AFO Days – 2; August 2-3, 2005)		**AFO Days:**	2
MNOPS CASE #: 005817				

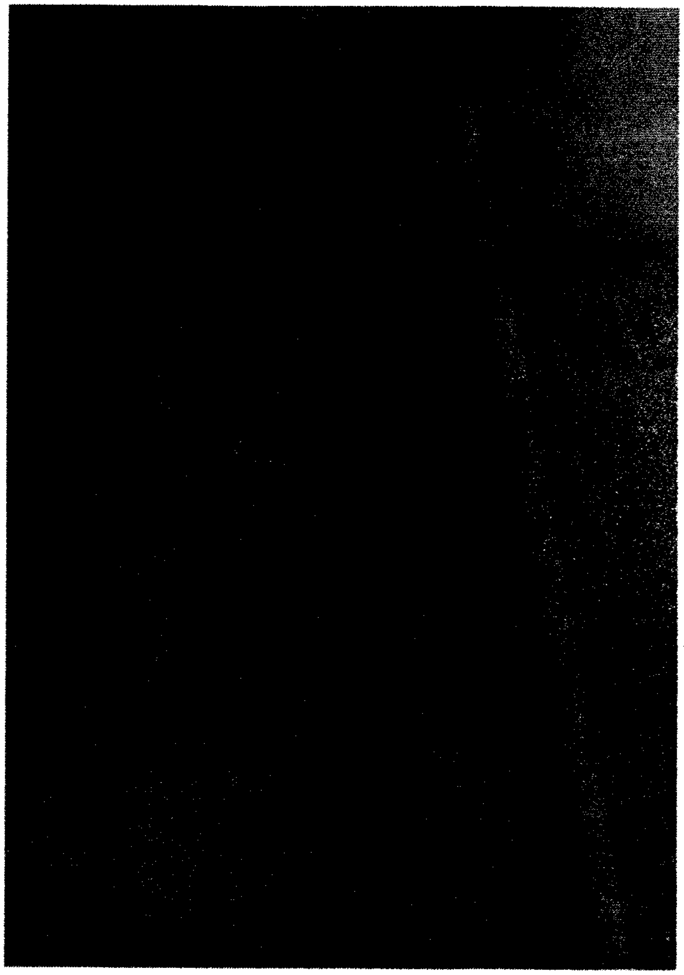
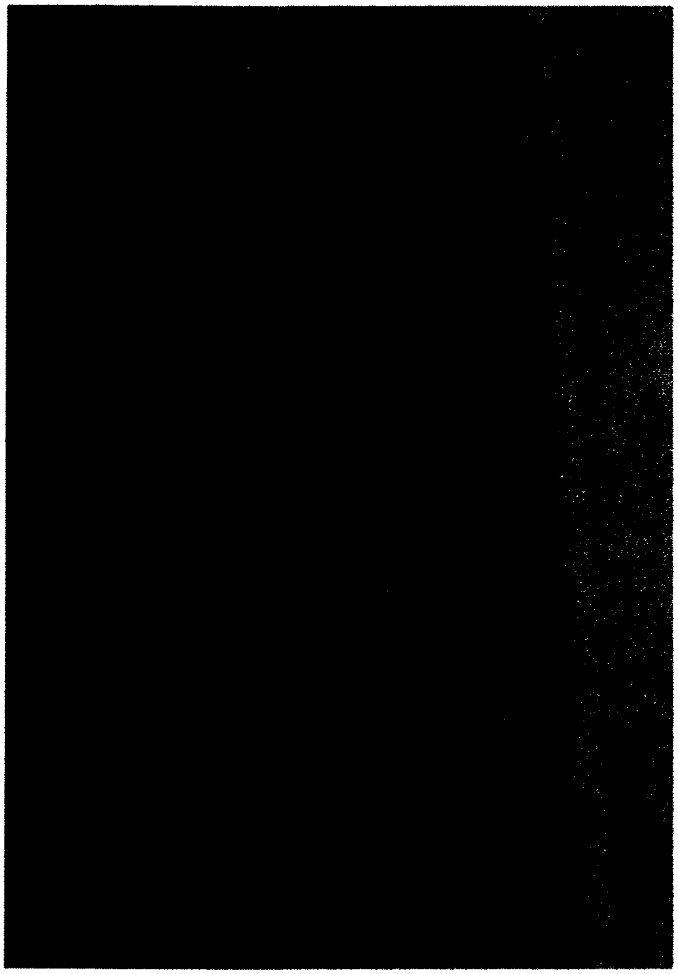
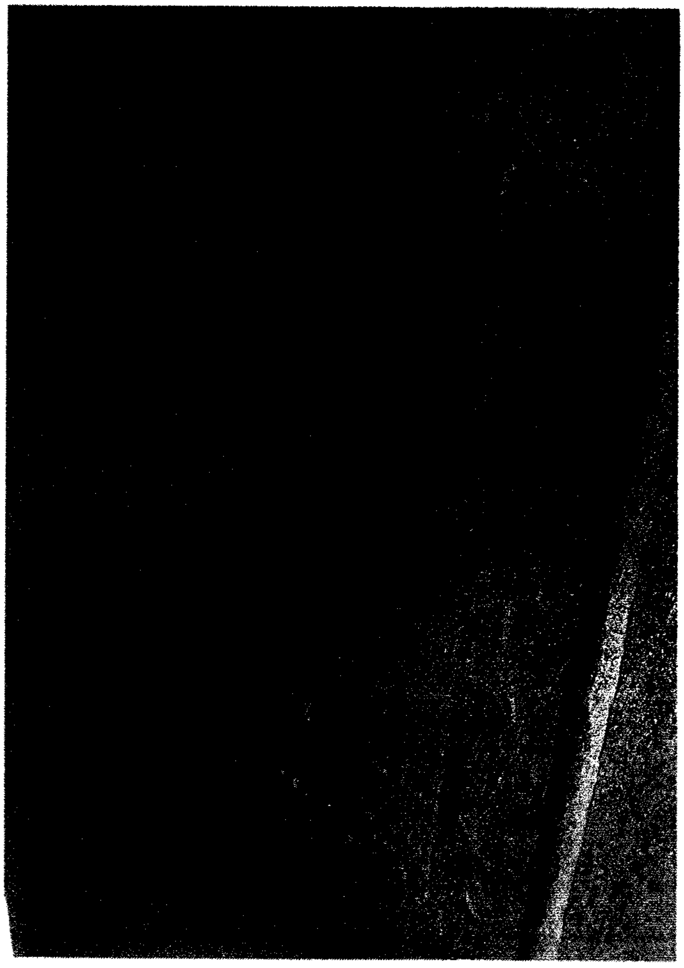
Summary: 8-2-05, SMS: I drove to the Deer River area from the Bemidji area. 8-3-05, SMS: Per a request from Brian Pierzina while he was in Detroit, I inspected two Enbridge verification dig locations near Cohasset, Minnesota. The Enbridge inspector was Craig Golpin. On-site contractors are Casper Construction (including exposure and preparation for inspection) and PFI NDE (including inspection and evaluation). Per Craig Golpin, Enbridge's 2000 crack tool run found some toe cracks in the long seam of the 34" crude oil pipeline where I observed the two digs.

First Observed Dig Site at MP 1002.29: Technician Mike Jeulson (PFI NDE) and Dennis Kaye aka "Hurricane" (Casper Construction, Grand Rapids). Polyken wrap had been removed and the pipe had been blasted prior to my arrival the first location at MP 1002.29. Mike Jeulson was evaluating toe cracks by magnetic particle flux (MFL) inspection method and ultrasonic testing with 30 degree offset transducer. Helper Dennis Kaye was observed to grind out the cracks. Later, Mike Jeulson was observed to be grinding out the cracks (see photos attached). Tool indications of crack depth were up to 30% of pipe wall, as verified in the field this day. A small colony of SCC was found adjacent to the long seam, and apparently this was not seen on the 2000 pig run.

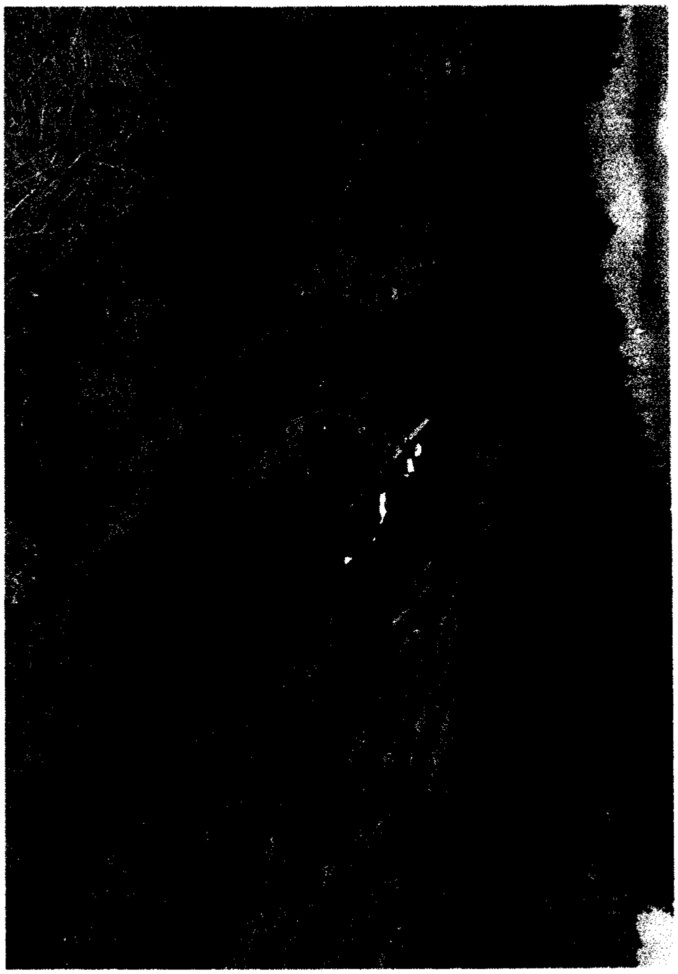
Second Observed Dig Site at MP 1002.00: This location is within site of the July 4, 2003, release location, approximately 500 feet to the west of the dig site. The inspector was Lowell Learn (Gulf Interstate Inspection, Houston, TX). They were in the process of blasting the 34" pipe, and had determined no indications to observe yet (see photos attached). Upon cleaning the pipe, they would be ready for inspection.







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.** Refer to the last page of this form for **PIM** example entries.

Inspection Report	**Post Inspection Memorandum**
Inspector/Submit Date: Phil Archuletta / 1-19-05	**Inspector/Submit Date:** Phil Archuletta / 11-12-04 P.A. **Peer Review/Date:** **Director Approval/Date:** 11/15/04

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	**Enbridge Energy, Limited Partnership**	**OPID #:**	11169
Name of Unit(s):	Bay City Griffith Fort Atkinson	**Unit # (s):**	295 1282 134
Records Location:	Griffith, IN		
Unit Type & Commodity:	Liquid / Crude & Products		
Inspection Type:	CE System	**Inspection Date(s):**	Records: 04/26/04 – 04/30/04 Field: 09/13/04 – 09/17/04 Field: 09/20/04 – 09/24/04 Field: 10/18/04 – 10/22/04
OPS Representative(s):	Phil Archuletta	**AFO Days:**	5.0 Records: 04/26/04 – 04/30/04 5.0 Field: 09/13/04 – 09/17/04 5.0 Field: 09/20/04 – 09/24/04 5.0 Field: 10/18/04 – 10/22/04

Summary:

On April 26-30, September 13–17, September 20-24 and October 18-22, I performed a CE system inspection of the Enbridge Energy Crude System #1 facilities contained in units 295 (Bay City), 1282 (Griffith) and 134 (Fort Atkinson). The inspection included a procedures, records and facilities review. A Joint O&M inspection was conducted in June, 2002 and thus only procedures with amendments since June, 2002 were evaluated during this inspection. Review of records at Enbridge Energy's Griffith, IN office and review of Enbridge Energy facilities in the states of Michigan, Indiana, Illinois and Wisconsin identified potential issues that are included in the "Findings:" section of this PIM.

Findings:

A. Review of Enbridge Energy's procedures identified the following issues: No non-compliance issues.

B. Review of Enbridge Energy's records identified the following issues: No non-compliance issues.

C. Field review of Enbridge Energy's field facilities identified the following issues:

(a) At MP 438.00, Mokena Station, the outer wrap at Unit #1 for both the suction and discharge piping is deteriorated at the pipe to soil interface.

(b) At MP 423.02, the pipe to soil reading is -0.802 which does not meet criteria.

(c) At MP 383.16, Dundee Station, inside the pump house there is corrosion taking place in the annular space where the slip-on flanges mate with the pipe on the suction and/or discharge side of some of the pump units. Rust has formed in the annular spaces, however, there was not any evidence of pitting.

(d) At MP 193.63, Vesper Station, the pipe support at the northeast side of the meter run is not in firm contact with the pipe and is not supporting the pipe.

(e) At MP 227.52, Adams Station, on the outside of the pump house at the southeast corner, the pad between the pipe support and pipe was dislodged.

(f) At MP 227.52, Adams Station, inside the pump house there is corrosion taking place in the annular space where the slip-on flanges mate with the pipe on the suction and/or discharge side of some of the pump units. Rust has formed in the annular spaces, however, there was not any evidence of pitting.

(g) At MP 270.77, on Line 14, there is a shorted casing. The pipe to soil reading was -0.974v for both the mainline pipe and the casing.

(h) At MP 321.33, Delavan Station, the pipe support for valve 6-U-1 on the discharge side of the unit is not in firm contact with the pipe and is not supporting the pipe.

(i) At MP 340.00, Walworth Station, inside the pump house there is corrosion taking place in the annular space where the slip-on flanges mate with the pipe on the suction and/or discharge side of some of the pump units. Rust has formed in the annular spaces, however, there was not any evidence of pitting.

(j) At MP 340.00, Walworth Station, inside the pressure control valve building the outer wrap on the piping at the pipe to soil interfaces is deteriorated.

(k) At MP 552.94, Vandalia Station, the mainline valve is a motor operated valve and during the inspection the valve did not operate properly under local remote control.

(l) At MP 1561.16 the indicator rod on valve 1561.16-5-V was not working properly.

NOTE: On 9-15-04, Enbridge personnel repaired and tested this valve successfully.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to Part 195 S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

Name of Operator: Enbridge Energy, Limited Partnership

H.Q. Address:	**System/Unit Address:**
Suite 3300 1100 Louisiana Houston, TX 77002-5217	Suite 3300 1100 Louisiana Houston, TX 77002-5217
Co. Official: Dan Tutcher, President **Phone No.:** 713-650-8900 **Fax No.:** 713-653-6711 **Emergency Phone No.:** 800-858-5253	**Activity Record ID#:** 111037, 109905, 109827, 109826 **Phone No.:** 713-650-8900 **Fax No.:** 713-653-6711 **Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
Marc Curry	Safety Coordinator	(219) 922-3133 Ext 225
Eric Williams	Senior Safety Coordinator	(219) 922-3133 Ext 224
Jay Johnson	Compliance Coordinator	(715) 394-1512
Kimberly Harris	Senior Corrosion Specialist	(219) 922-3133 Ext 202
Mark Varichak	Operations Engineer	(219) 922-3133 Ext 228
Garry Thompson	Operations Supervisor	(219) 922-3133 Ext 218
** Allan Baumgartner	Control Center Supervisor	(780) 420-8132 (Canada)
** Gary Kosch	Control Center Coordinator	(780) 420-8598 (Canada)
** Mei Lai	Information System Specialist	(780) 420-8234 (Canada)
** Les Reschny	Systems Analysis II	(780) 420-8268 (Canada)
** Don Scott	SCADA Engineering Specialist	(780) 420-8118 (Canada)
** Adam Erickson	Operations Engineer	(715) 394-1548
Thomas Sims	Technical Supervisor	(219) 922-3133 Ext 212
Edward Ostrowski	One Call Dispatcher	(219) 922-3133 Ext 220
Ray Wyckoff	Corrosion Technician	(219) 922-3133 Ext 236
Jarrett Kachur	Technical Supervisor	(989) 684-0160 Ext 30
Kent Nikel	Engineer	(715) 394-1598
Fred Hipshear	Right of Way Agent	(269) 323-2491
Russell Carson	Corrosion Technician	(269) 323-2491 Ext 13
Dave Rew	Area Engineer	(269) 323-2491 Ext 15

** *INDICATES THESE INDIVIDUALS WERE INTERVIEWED VIA TELE-CONFERENCE CALL.*

Company System Maps (copies for Region Files): YES, placed in the operator's file

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

Unit Description:

System Description: From the Superior (WI) Terminal (not including the terminal itself) southeasterly through Chicago, IL then northeasterly to the US/Canada border near Sarnia, Canada then northwesterly to the Lewiston, MI station.

System Name: Lakehead Crude System #3

Central Region Units in the System:
Unit #134 – Fort Atkinson: 34" line #6A from the Superior, WI terminal southeasterly to MP 385.99 (south of Dundee, IL.). 24" line 14 from the Superior, WI terminal southeasterly to MP 384.00 (Burlington, IL station – includes the station).

Unit #295 – Bay City: 30" line 5 - from MP 1548.60 (Lewiston Pump Sta.) to MP 1735.06 (Canadian / US border) near Marysville, MI. 30" line 6B - from MP 751.22 (Canadian / US border) near Marysville, MI to MP 519.96 (Timothy Road in New Carlisle, IN). 10" & 12" line 17 from MP 0.00 at the Stockbridge, MI station to MP 35.80 at the tie-in with Wolverine at Freedom Junction.

Unit #1282 – Griffith: 34" line 6A from MP 385.99 (south of Dundee, IL.) to MP 465.38 (Griffith). 30" line #6B from MP 465.38 (Griffith) to MP 519.96 (Timothy Road centerline in New Carlisle, IN.). Line 14 from MP 438.40 (Mokena, IL station) to MP 384.00 (Burlington station – not including the station itself).

Portion of Unit Inspected *(not required if covered in the PIM)*:

From the Ladysmith, WI station southeasterly through Chicago, IL then northeasterly to the US/Canada border near Sarnia, Canada then northwesterly to the Lewiston, MI station. Inspection included Line 17 from the Stockbridge station to Toledo, OH.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

	CONVERSION TO SERVICE	S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?			✔	

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*
Enbridge Energy does not have any pipelines that have been converted.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
.402(a) .402(c) (2)	.50	Procedures for gathering data needed for reporting accidents in a timely and effective manner.				✔
		Accident report criteria, as detailed under 195.50. A release of 5 gals or more may be required to be reported.				✔
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				✔
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				✔
	.54(b)	Supplemental report - required within 30 days of information change/addition				✔
	.55	Safety-related conditions (SRC) - criteria				✔
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				✔
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*
A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

		SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*
A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

		SUBPART D - WELDING PROCEDURES	S	U	N/A	N/C
		Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.				
.402(c)/ .422	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.				✔
		Welding procedures must be qualified by destructive testing.				✔
	.214(b)	Each welding procedure must be recorded in detail, including results of qualifying tests.				✔
		Are welding procedures qualified in accordance with a standard that is accepted by the industry? **(API 1104, ASME Boiler & Pressure Code - Section IX, or other)**				✔
	.222(a)	Welders must be qualified in accordance with **Section 3 of the API Standard 1104 (18th Ed., 1994)** or **Section IX of the ASME Boiler and Pressure Vessel Code (1995)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition.				✔
	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 6 of API 1104.	✔			
Alert Notice 3/13/87		**In the welding of repair sleeves and fittings, do the operator's procedures give consideration to:**				
		1. The use of low hydrogen welding rods.	✔			
		2. Cooling rate of the weld.	✔			
		3. Metallurgy of the materials being welded (weldability carbon equivalent).	✔			
		4. Proper support of the pipe in the ditch.	✔			
.402(c)/ .422	.226(a)	Arc burns must be repaired.				✔
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestruct. testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				✔
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

		WELDS: ACCEPTABILITY - NONDESTRUCTIVE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.228 /.234	Do procedures require welds to be nondestructively tested to insure their acceptability according to **Section 6 of API 1104 (18th)** and per the requirements of **§195.234** in regard to the number of welds to be tested?				✔
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				✔
		2. By qualified personnel				✔
		3. By a process that will indicate any defects that may affect the integrity of the weld				✔
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

WELDS: REPAIR or REMOVAL of DEFECT PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.230	Welds that are unacceptable (Section 6 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.302(a)	Each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be pressure tested.				✔
	.302(b)	Lines that have not been pressure tested per subpart E must be operated in accordance with Subpart E.				✔
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				✔
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				✔
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines).				✔
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				✔
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				✔
	.303	Procedures for the risk based alternative to pressure testing?				✔
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				✔
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with §195.302.				✔
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				✔
	.306	Appropriate test medium				✔
	.308	Pipe associated with tie-ins must be pressure tested.				✔
	.310(a)	Test records must be retained for useful life of the facility.				✔
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				✔
	.310(b)(2)	Test instrument calibration data.				✔
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				✔
	.310(b)(4)	Date and time of the test.				✔
	.310(b)(5)	Minimum test pressure.				✔
	.310(b)(6)	Test medium.				✔

SUBPART E - PRESSURE TESTING PROCEDURES (Con't)			S	U	N/A	N/C
.402(c)/ .422	.310(b)(7)	Description of the facility tested and the test apparatus.				✔

			S	U	N/A	N/C
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				✔
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				✔
	.310(b)(10)	Temperature of the test medium or pipe during the test period.	✔			

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*
A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.402	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				✔
		b. Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				✔
		c. Appropriate parts must be kept at locations where O&M activities are conducted.				✔

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MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				✔
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				✔
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				✔
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				✔
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?				✔
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				✔
	.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards.				✔

MAINTENANCE & NORMAL OPERATION PROCEDURES (Con't)			S	U	N/A	N/C
		Reporting abandoned pipeline facilities under commercially navigable waterways per §195.59				
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				✔

			S	U	N/A	N/C
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				✔
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				✔
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				✔

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ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		I. Unintended closure of valves or shutdowns?				✔
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				✔
		iii Loss of communications?				✔
		iv. The operation of any safety device?				✔
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				✔
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				✔
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				✔
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice ~~of~~ an abnormal operation is received?				✔
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				✔

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STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		EMERGENCY PROCEDURES	S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				✔
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				✔
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				✔
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				✔
	.402(e)(5)	Controlling the release of liquid at the failure site?				✔
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				✔
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				✔
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?			✔	
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				✔

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		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under §195.402.				✔
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				✔
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				✔
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				✔
	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition.	✔			
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions				✔
	.403(b)	At intervals not exceeding 15 months, but at least once each calender year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				✔
	.403(b)(2)	Make appropriate changes to the emergency response training program				✔
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures they are responsible for				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
.402(a)	**.402(c)(1)**	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				✔
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		I. Breakout tanks				✔
		ii. Pump stations				✔
		iii. Scraper and sphere facilities				✔
		iv. Pipeline valves				✔
		v. Facilities to which **§195.402(c)(9)** applies				✔
		vi. Rights-of-way				✔
		vii. Safety devices to which **§195.428** applies				✔
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				✔
	.404(a)(3)	The maximum operating pressure of each pipeline.				✔
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				✔
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				✔
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under **§195.402** apply.				✔
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				✔
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				✔
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.				✔

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MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by **§195.106**.				✔
	.406(a)(2)	The design pressure of any other component on the pipeline.				✔
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				✔
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				✔
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				✔
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				✔

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COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
.402(a)	.408(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				✔
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **§195.402(c)(9)**.				✔
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				✔
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				✔
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				✔

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LINE MARKER PROCEDURES			S	U	N/A	N/C
.402(a)	.410(a)	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				✔
	.410(a)(2)	Must have the correct characteristics and information				✔
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				✔

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INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	**.412(a)**	Operator must inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**				✔
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**.				✔

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UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
.402(a)	**.413(b)**	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator:				
	.413(b)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center.			✔	
	.413(b)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation.			✔	
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections			✔	

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The system inspected for this operator does not have any offshore pipeline facilities.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	**.420(a)**	Operator must maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times.				✔
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year.				✔
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				✔

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		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	.422(a)	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				✔
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				✔

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		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				✔
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.			✔	
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.			✔	
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**			✔	
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.			✔	
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.			✔	
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.			✔	

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		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.426	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				✔
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				✔

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OVERPRESSURE SAFETY DEVICE PROCEDURES			S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				✔
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				✔
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.			✔	
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**.			✔	
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to the appropriate API. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				✔
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				✔

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FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				✔
		The equipment must be:				
		a. In proper operating condition at all times.				✔
		b. Plainly marked so that its identity as firefighting equipment is clear.				✔
		c. Located so that it is easily accessible during a fire.				✔

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BREAKOUT TANK PROCEDURES			S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**; (Reference 195.1)				✔
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 4 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **§195.402(c)(3)**.				✔
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.**				✔

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		BREAKOUT TANK PROCEDURES (Con't)	S	U	N/A	N/C
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier.				✔
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

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		SIGN PROCEDURES	S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				✔
		Signs must contain the name of the operator and a telephone number where the operator can be reached at all times.				✔

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		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				✔

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		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				✔

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		PUBLIC EDUCATION PROCEDURES	S	U	N/A	N/C
.402(a)	.440	Is there a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				✔
		Is the program conducted in English and other languages where appropriate?				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*
A Joint O&M inspection was conducted in June, 2002 and thus only procedures were evaluated during this inspection that covered amendments since June, 2002 with the exception that amendments covering IMP and OQ issues were not evaluated. Amendments covering IMP and OQ are covered by special IMP and OQ inspection teams.

		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				✔
	.442(b)	Does the operator participate in a qualified One-Call program?				✔
	.442(c)(1)	Include the identity, on current a basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				✔
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph **(c)(1)** of this section of the following, as often as needed to make them aware of the damage prevention program:				
		I. The program's existence and purpose.				✔
		ii. How to learn the location of underground pipelines before excavation activities are begun.				✔
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				✔
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				✔
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				✔
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		I. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				✔
		ii. In the case of blasting, any inspection must include leakage surveys.				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*
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		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				✔

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*
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PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
§195.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES		S	U	N/A	N/C
§195.501-509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				✔

SUBPART H - CORROSION CONTROL PROCEDURES			S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.				✔
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				✔
		a) constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**				✔
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				✔
		2) Is a segment that is relocated, replaced, or substantially altered.				✔
	.559	**Coating Materials;** Coating material for external corrosion control must; a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				✔
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				✔
		b. All coating damage discovered must be repaired.				✔
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				✔
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				✔
		2) Is a segment that is relocated, replaced, or substantially altered.				✔
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				✔
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				✔
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				✔
	.567	Test leads installation and maintenance				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		SUBPART H - CORROSION CONTROL PROCEDURES (Con't)	S	U	N/A	N/C
.402(a)	.569	Examination of Exposed Portions of Buried Pipelines				✔
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-96** (incorporated by reference)				✔
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**				✔
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**				✔
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-96.**				✔
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment.				✔
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.**				✔
		Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				✔
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2 ½ months.**				✔
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b).**				✔
	.575	Are there adequate provisions for electrical isolations?				✔
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects? b. Design & install CP systems to minimize effects on adjacent metallic structures.				✔
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken?				✔
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion				✔
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**				✔
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				✔
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement)				✔
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				✔
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**			✔	
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				✔
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				✔
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)**				✔
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**)				✔

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Best Practice:

What process does the Operator have to address Alert Notices?

Comments: Compliance and Integrity Management groups coordinate the dissemination of information from alert notices.

Best Practice: Stress Corrosion Cracking

Pipeline Safety Advisory Bulletin ADB-03-05 - October 8, 2003

Reference http://www.gpoaccess.gov/fr/advanced.html **fr06oc03N Pipeline** Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Liquid Pipelines).

Is the operator aware of the bulletin, and is the operator reviewing their system for the potential of SCC?

Y/N Y ***The operator has SCC areas and SCC is an extensive part of their IMP program for analysis and monitoring.***

Best Practices: Damage Prevention

(If operator's damage prevention best practices answers have not changed since the previous inspection and are noted as such, then completion of the below 7 questions is not required).

1. Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities? Y/N Y

2. Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors? Y/N Y

3. Does the operator's damage prevention program include pro-active liaison with local school officials, where transmission pipelines traverse or are adjacent to school property? Y/N Y

4. Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices? Y/N Y

5. Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan? Y/N Y

6. Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study? Y/N Y

7. Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices? Y/N Y

Damage Prevention Comments:

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PART 195 - FIELD REVIEW		S	U	N/A	N/C
.120	Have new pipelines, or pipeline sections of which pipe or components have been replaced, been designed and constructed to accommodate smart pigs ? (See exceptions under (b) and (c))	✔			
.262	Pumping Stations	✔			
.262	Station Safety Devices	✔			
.308	Pre-pressure Testing Pipe - Marking and Inventory	✔			
.403	Emergency Response Training	✔			
.410	Right-of-Way Markers	✔			
.412	River Crossings	✔			
.557	Cathodic Protection (test station readings, other locations to ensure adequate CP) levels)		✔		
.573	Pipeline Components Exposed to the Atmosphere		✔		
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	✔			
.420	Valve Maintenance		✔		
.420	Valve Protection from Unauthorized Operation and Vandalism	✔			
.426	Scraper and Sphere Facilities and Launchers	✔			
.428	Pressure Limiting Devices	✔			
.428	Relief Valves - Location - Pressure Settings - Maintenance	✔			
.428	Pressure Controllers	✔			
.430	Fire Fighting Equipment	✔			
.432	Breakout Tanks	✔			
.434	Signs - Pumping Stations - Breakout Tanks	✔			
.436	Security - Pumping Stations - Breakout Tanks	✔			
.438	No Smoking Signs	✔			
.501-.509	Operator Qualification Questions	✔			

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	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION to SERVICE				
.5(a)(1)	Testing to Verify MOP (ASME<Appendix N)			✔	
.5(a)(2)	Inspection of Pipeline Right-of-Way			✔	
.5(c)	Pipeline Records (Life of System)			✔	
	Pipeline Investigations			✔	
	Pipeline Testing			✔	
	Pipeline Repairs			✔	
	Pipeline Replacements			✔	
	Pipeline Alterations			✔	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)			✔	
.52	Telephonic Reports to NRC (800-424-8802)	✔			
.54(a)	Written Accident Reports (DOT Form 7000-1)	✔			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)			✔	
.56	Safety Related Conditions	✔			
.57	Offshore Pipeline Condition Reports			✔	
.59	Abandoned Underwater Facility Reports			✔	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	✔			
.214(b)	Test Results to Qualify Welding Procedures	✔			
.222	Welder Qualification	✔			
.234(b)	Nondestructive Technician Qualification	✔			
.589	Cathodic Protection	✔			
.266	Construction Records	✔			
.266(a)	Total Number of Girth Welds	✔			
	Number of Welds Inspected by NDT	✔			
	Number of Welds Rejected	✔			
	Disposition of each Weld Rejected	✔			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	✔			
.266(c)	Location of each Crossing with another Pipeline			✔	
.266(d)	Location of each buried Utility Crossing			✔	
.266(e)	Location of Overhead Crossings			✔	
.266(f)	Location of each Valve and Test Station	✔			
	PRESSURE TESTING				
.310	Pipeline Test Record	✔			
.305(b)	Manufacturer Testing of Components	✔			
.308	Records of Pre-tested Pipe	✔			

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	PART 195 - RECORDS REVIEW (Con't.)	**S**	**U**	**N/A**	**N/C**
	OPERATION & MAINTENANCE				
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	✔			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	✔			
.402(c)(10)	Abandonment of Facilities			✔	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	✔			
.402(c)(13)	Review of work Performed by Personnel (periodically)	✔			
.402(d)(1)	Response to Abnormal Pipeline Operations	✔			
.402(d)(5)	Review of Personnel Response to Abnormal Operations	✔			
.402(e)(1)	Notices of Emergencies	✔			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	✔			
.402(e)(9)	Post Accident Reviews	✔			
.403(a)	Emergency Response Personnel Training Program	✔			
.403(b)	Review of Personnel Perform., Emer. Response Program Changes (**1 per yr/15 months**)	✔			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	✔			
.404(a)(1)	Maps or Records of Pipeline System	✔			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	✔			
.404(a)(3)	MOP of each Pipeline	✔			
.404(a)(4)	Pipeline Specifications	✔			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	✔			
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs)	✔			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	✔			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	✔			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	✔			
.406(a)	Establishing the MOP	✔			
.412(a)	Inspection of the ROW	✔			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways ***No inspections since 2001. Next inspections scheduled for 2006.***			✔	
.413(b)	Inspection of Pipelines in Gulf of Mexico			✔	
.420(b)	Inspection of Mainline Valves	✔			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non hvl; **2 per yr/7½ months** hvl)	✔			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals n.t.e. **5 yrs**).			✔	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non hvl; **2 per yr/7½ months** hvl)	✔			
.430	Inspection of Fire Fighting Equipment	✔			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	✔			
.440	Public Education	✔			

PART 195 - RECORDS REVIEW (Con't.)		S	U	N/A	N/C
DAMAGE PREVENTION PROGRAM					
.442(c)(1)	List of Current Excavators	✔			
.442(c)(2)	Notification of Public/Excavators	✔			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	✔			
CORROSION CONTROL					
.569	Inspection of Exposed Pipelines (External Corrosion)	✔			
.573(a)	External Corrosion Control - Protected Pipelines	✔			
.573(b)	External Corrosion Control - Unprotected Pipelines			✔	
.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	✔			
.573(d)	External Corrosion Control - Bottom of Breakout Tanks	✔			
.579(a)	Corrosive effect investigation	✔			
.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment	✔			
.579(c)	Inspection of Removed Pipe for Internal Corrosion	✔			
.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**	✔			
.589	Cathodic Protection (Maps showing anode location, test stations, CP systems, etc)	✔			

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Oil Pollution Act High Impact Inspection (49 CFR 194)

	Field Verification of Facility Response Plan Information	Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	✔		
194.111	RSPA Tracking Number: **866 Superior Region 867 Chicago Region** Approval Date: **1/27/04 (Pending approval letter)**			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	✔		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	✔		
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	✔		
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]	✔		

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

OPA Inspection Guidance

__OPA-1__ - **RSPA Tracking Number**: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

__OPA-2__ - **Names and phone numbers**: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

__OPA-3__ - **Proof of OSRO contract**: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

__OPA-4__ - **Exercise documentation**: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

__OPA-5__ - **Training records**: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1
Scada Liquid Worksheet

The topics on this worksheet regard general SCADA functionality. A more thorough SCADA evaluation may be warranted based on the results of this worksheet or prompts by other events.

1. **Pipeline Safety Advisory Bulletins (reference http://www.gpoaccess.gov/fr/advanced.html)**

   Review the following with the operator:

   • July 7, 1999 Advisory Bulletin ADB-99-03 (Ref.**fr16jy99N Potential Service Interruptions in Supervisory Control and Data Acquisition Systems)** - discuss SCADA system performance.

   • December 16, 2003 Advisory Bulletin ADB-03-09 (Ref. **fr23de03N Pipeline Safety: Potential Service Disruptions in Supervisory Control and Data Acquisition Systems**) – discuss consideration of possible SCADA system disruptions caused by system maintenance or upgrade.

Comments: Bulletins discussed with operator. Operator has redundant servers. The operator's CPU usage is normally in the range of 10% to 20%. The operator strives to maintain CPU usage at something less than 60%. A separate development work station is used for testing. Back-up system uses continuous current data so that there is no interruption in case a switch over is required. The operator's SCADA system has about 20 to 30 personnel to provide support and development.

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. **195.402(d)(1)(iii) - Loss of communications.**

   • Off-site Back-up Center
   • Data transfer to redundant or off-site processors
   • Battery and/or Emergency Generator
   • Redundant data communications paths, automatic restoration or manual?
   • Data Reduction & Archiving.
   • Indication of stale, forced or manually overridden data, or system lock-up
   • Operating practices during data communications outages

Comments: Enbridge Energy has a back-up control center located in Superior, WI. The back-up center has 5 to 6 consoles and in the event that a console fails, any one of the other consoles can be used. If for any reason, the building housing the control center at Edmonton had to be evacuated, then the control center would shut-down all pipelines and personnel would temporarily relocate to a another back-up control center at a Edmonton terminal that is approximately 15 to 20 minutes from the main control center. Control personnel would then begin a systematic re-start of all pipelines. Back-up control centers are tested a minimum of two times per year.

3. **§195.404 - Pump station discharge pressure records.**

   • Discharge Pressure records in SCADA or at field locations?
   • Data Reduction & Archiving
   • Data acquisition frequency

Attachment 1
Scada Liquid Worksheet

Comments: Enbridge Energy has begun a program to replace pen & ink pressure recorders with digital pressure recorders. Currently, 40 out of approximately 100 recorders have been replaced. These are six channel digital recorders which look at pressure every second, records the pressure every minute and records the highest and the lowest pressure within that one minute span, however, the exact time of each high/low is not kept. If an event causes a cascade shut-down, then the recorders capture all pressures between 5 minutes before and 5 minutes after the shut-down. The pressure data is stored on zip disks and one year's worth of data can be stored on one zip disk. The data is also sent and recorded at Enbridge Energy's headquarters server as a backup.

4. §195.404 Maps and records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:
(1) Location and identification of the following pipeline facilities:
(I) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c) (9) applies;
(vii) Safety devices to which §195.428 applies.
(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations
- Ensure pipeline safety parameters are current (i.e.: MOP, alarm set points, etc.)
- Review any emergency or abnormal operating condition or schedule deviation records generated by the SCADA system (alarm logs, trending data, etc.). Compare abnormal operating conditions noted in the SCADA data with the Operator's report and reporting procedures as related to those abnormal operating conditions.
- Data Reduction & Archiving
- Data acquisition frequency

Comments: Enbridge Energy's actual SCADA system is located in Edmonton, Alberta, Canada and thus an actual on-site inspection of the SCADA system was not completed.

5. §195.408 - Communications.

(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system
(b)(1) Monitoring operational data as required by §195.402(c)(9)
- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-Short Reports

- Maintaining pressures within limits described in **§195.406 Maximum Operating Pressure**

Comments: Continuous data transmission with field locations. The operator has redundant communication paths. Critical alarms are classified and color coded on the display. Trending data is used that will trigger alarms if allowable values are exceeded. Over/short reports are done every 2 hours. Event logs can be generated.

6. §195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance

- Over-Short Reports
- Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments: Leak detection systems are provided for Lines 1, 2, 3, 5 and 13. A leak detection system for Line 4 is almost ready, the system is installed but the alarms are not active because they are fine tuning the settings. A leak detection system for Line 6 has been budgeted. Leak detection is not provided for Lines 14 and 17(probably will be done next year). The system used is a Stoner Leak Detection System which uses real time transient hydraulic modeling of the pipelines. The system compares the model with what is actually occurring on the pipelines. The sensitivity ranges vary for each line, but an example would be Line 3 where the sensitivity is 28% of total flow over 5 minutes, 11% over 20 minutes and 6% over 2 hours. The leak detection system is part of the "10 minute" rule, which means that if the reason for a leak detection indication cannot be resolved within 10 minutes, then the line will be shut-down.

7. §195.420 & .428 - Testing of applicable SCADA controlled valves, safety devices, and overfill systems functionality.
   - Frequency of testing
   - Inclusion of SCADA component in the tests

Comments: Most SCADA valves are being used daily and thus operation can be checked daily. Alarms are activated if there is a component failure. MOV valves are tested twice per year and are witnessed by field personnel. Other components (such as tank Hi-Hi alarms) are tested back to the SCADA system. There are monthly SCADA checks on the tank level alarms.

Attachment 2
Internal Corrosion Worksheet - Liquid Pipelines

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: ✔ N: _____

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: ✔ N: _____

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: ✔ N: _____

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y: ✔ N :_____

5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: ✔ N: _____

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y: _____ N: ✔

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y: ✔ N:_____

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion? Y: ✔ N: _____

9. Does the operator track internal corrosion and take corrective action to prevent recurrence? Y: ✔ N: _____

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
    - _____ Gas and Fluid analysis
    - _____ Rates of pipeline corrosion as determined by coupons
    - ✔ Solids removed from the system
    - ✔ Analysis of inhibitor samples from the pipeline
    - _____ Magnetic and electronic device (pigs)
    - ✔ Other ***Hydrogen Foils (Beta Foils)***

11. Is the inhibitor compatible with the product being transported? Y: ✔ N: _____ N/A: _____

Comments:

Attachment 3
Operator Qualification Worksheet

The following questions are to be used by the inspector to provide information in determining a need for a more intensive OQ field inspection.

1. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual's performance of a covered task may have contributed to an accident?

> Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):*
> **Interviewed Garry Thompson, Operations Supervisor at Griffith for his response to this OQ issue. Mr. Thompson's response was satisfactory and in accordance with the operator's OQ plan procedures.**

2. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual is identified that may no longer be qualified to perform a covered task?

> Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):*
> **Interviewed Garry Thompson, Operations Supervisor at Griffith for his response to this OQ issue. Mr. Thompson's response was satisfactory and in accordance with the operator's OQ plan procedures.**

3. Do the individuals performing covered tasks know how to recognize and react to AOC's that may be encountered while performing tasks?

> Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):*
> **Refer to attached "Operator Qualification Field Inspection" sheet from field review.**

4. Are the employee and/or contractor individuals observed performing covered tasks qualified per OQ program requirements? (Documentation may be a hard copy or database records available at the job site or local office).

> Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):*
> **Refer to attached "Operator Qualification Field Inspection" sheet from field review.**

5. Are the individuals who are observed performing covered tasks adhering to operator's procedures?

> Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):*
> **Refer to attached "Operator Qualification Field Inspection" sheet from field review.**

Operator Qualification Field Inspection

Date: October 20, 2004 **Operator:** ENBRIDGE ENERGY **Job #:** **Location:**

Company Supervisor / Foreman: JARRETT KACHUR - TECHNICAL SUPERVISOR

Contractor #1 Name: **Contractor Supv. / Foreman:**

Contractor #2 Name: **Contractor Supv. / Foreman:**

No.	Tasks	JARRETT KACHUR - TECHNICAL SUPERVISOR		JOHN BISSELL - SENIOR CORROSION TECHNICIAN		RON COOK - DELIVERY GAUGER (MARYSVILLE)								Comments
		Performed	Qualified	Performed	Qualified	Performed	Qualified	Performed	Qualified	Performed	Qualified	Performed	Qualified	
		Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	Y/N	
1	Supervisor - Post Incident	Y	Y											
2	Rectifier Inspection" EP277			Y	Y									
3	Pipe to Soil Survey			Y	Y									
4	"External Coating Inspection"			Y	Y									
5	General Site Security - Book 7 Emergency Response					Y	Y							
6	Delivery Gauger - Marysville					Y	Y							
7														
8														

Notes: All responses to OQ questions during the field inspection were satisfactory and in accordance with the operator's OQ procedures.

PIM Entry Examples

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	NoFail Pipeline Company	**OPID #:**	2314
Name of Unit(s):	Boardwalk and Parkplace	**Unit # (s):**	234, 278
Records Location:	Pipelineville, NC		
Unit Type & Commodity:	Interstate Hazardous Liquid (A1) - HVL		
Inspection Type:	Standard	**Inspection Date(s):**	12/24-27/03
OPS Representative(s):	John Brown	**AFO Days:**	4

Summary:

On December 24-27, I performed a standard inspection of the NoFail pipeline facilities contained in units 234 and 278. The evaluation report contains a component description of the two units. The inspection included a records and facilities review. A Joint O&M inspection was conducted in 2003 and no procedures were evaluated during this inspection. Pre-inspection preparation identified previous valve inspection violations: I reviewed all of the company's valve inspection records and five aboveground valve settings and did not identify any potential non-compliances. Right-of-way inspection and periodic cathodic protection checks were conducted between Chance, NC to Community Chest, NC and from Reading, SC to Ventnor, SC. The Mighty Big'nWet River crossing was evaluated for atmospheric corrosion.

Findings:

The pipeline facilities appeared to be well maintained and serious concerns were noted: surface rusting was observed at the Pipelineville pump station. No pitting was observed. NoFail is in the process of repainting all of the aboveground piping at this facility.

The following concerns were noted from the records review:

1. The rectifiers in Unit 234 were inspected on 3 times in 2001, twice in 2002, and five times in 2003. Copies of the subject records were obtained.
2. The right-of-way in Unit 234 was densely overgrown such that aerial patrols would be ineffective. Pictures were taken of representative areas.

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

1. Pipeline Safety Advisory Bulletin - ADB-03-05 - October 8, 2003
   - Review Bulletin with operator, if operator is not familiar with.

Comments:
Familiar with bulletin.

2. Has the pipeline system ever experienced SCC (in service, out of service, leak, non-leak)?
   - Type of SCC (high pH or low/near neutral pH)?
   - What are the known risk indicators that may have contributed to the SCC?

Comments:

Non-leak, in service, near neutral pH SCC has been observed. The known associated risk indicators were:

- age >10years
- failed coating (typically polyethylene tape although one occurrence of SCC on coal tar enamel was observed).

3. Does the operator have a written program in place to evaluate the pipeline system for the presence of SCC? If no, have operator explain. If operator has not considered SCC as a possible safety risk, go to #10.

Comments:
As part of an overall defect management program, a written SCC Management Program is in place.

4. Has/does the operator evaluate the pipeline system for the presence of SCC risk indicators?

Comments:
Yes, potential risk indicators are used to determine our pipeline system's potential susceptibility to SCC. Some of these risk indicators are SCC history, coating type, installation year, operating parameters and soils landscape models. In addition, Enbridge utilizes the loading / unloading rate associated with pressure cycling as a SCC risk indicator.

5. Has the operator identified pipeline segments that are susceptible to SCC?

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

Comments:

Yes, within our SCC Management Program, the type of external coating broadly determines a line segment's potential SCC susceptibility. Other risk indicators are evaluated and used to rank line segment's potential SCC susceptibility. When SCC detection using an in-line inspection tool is deemed necessary, the tool currently used is a high-resolution ultrasonic tool.

6. If conditions for SCC are present, are written inspection, examination and evaluation procedures in place?

Comments:

Yes, written inspection, examination and evaluation procedures for SCC are documented within the SCC Management Program.

7. Does the operator have written remediation measures in place for addressing SCC when discovered?

Comments:

Written remediation measures for addressing SCC are documented within the SCC Management Program and within the company's Operating & Maintenance Procedures Manuals.

8. What preventive measures has the operator taken to prevent recurrence of SCC?
    - Modeling?
        - Crack growth rate?
        - Comparing pipe/environ./cp data vs. established factors?
        - Other?
    - Hydrotest program?
    - Intelligent pigging program?
    - Pipe re-coating?
    - Operational changes?
    - Inspection program?
    - Other?

Comments:

Once SCC has been identified, trending and analysis is performed to identify possible factors related to SCC initiation and growth. These results are combined with risk assessment models to determine appropriate mitigative actions. These actions have included changes to in-line inspection programs and operational changes.

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

9. Does the operator incorporate the risk assessment of SCC into a comprehensive risk management program?

Comments: Yes, Enbridge's risk management program incorporates qualitative and quantitative risk factors associated with the risk assessment of SCC.

Continue below for those operators who have not considered SCC as a possible safety risk.

10. Does the operator know of pipeline and right of way conditions that would match the risk indicators for either classical or non-classical SCC? See typical risk indicators below.

Comments:

High pH (Classical) SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
- Age >= 10 years
- Operating stress > 60% smys
- Pipe temperature >100 deg. F (typically < 20 miles d/s of compression)
- Damaged pipe coating
- Soil Characteristics
- Soil pH range: 8.5 to 11
- Alkaline carbonate/bicarbonate solution in the soil
- Elevated soil temperature contributing to elevated pipe temperature
- Polarized cathodic potential range: -600 to -750 mV, Cu/$CuSO_4$

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

Low or Near-Neutral pH (non-Classical) SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
  - Age >= 10 years
  - Frequently associated with metallurgical features, such as mechanical damage, longitudinal seams, etc.
  - Protective coatings that may be susceptible to dis-bondment
    - Any coating **other than** correctly applied fusion bonded epoxy, field applied epoxies, or coal tar urethane . . .
    - Coal tar
    - Asphalt enamels
    - Tapes
    - Others
- Soil Characteristics
- Soil pH range: 4 to 8
  - Dissolved CO_2 and carbonate chemicals present in soil
    - Organic decay
    - Soil leaching (in rice fields, for example)
  - "Normal" cathodic protection readings (dis-bonded coating shields the pipe from cp current)

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	ENBRIDGE ENERGY	Date(s):	10/18 – 22/04
Unit:	UNIT #295 BAY CITY		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
MP 1548.57 Lewiston						
Station						
1548.57-5-V valve	L5	-2.448				
5-SDV-1 valve	L5	-4.200				
Delivery line to MarkWest		-2.414				
1548.64-5-V valve	L5	-4.450				
Rectifier				76.30	2.86	
MP 1561.18 Cherry Creek						
Rd						
1561.16-5-V valve	L5	-1.809				
MP 1571.48						
1571.48-5-V valve	L5	-1.074				
MP 1580.55	L5	-1.766				
MP 1587.10 Engel Rd	L5	-1.725				
MP 1592.09 West Branch						
Station						
5-USV-31 valve	L5	-9.380				
5-USV-21 valve	L5	-12.740				
5-UDV-11 valve	L5	-5.290				
PCV piping		-2.197				
Sta. By-pass BV		-1.603				
1592.16-5-V valve		-1.558				
Rectifier				35.15	2.10	
MP 1605.97 Sterling Truck						
Rd	L5	-1.705				
MP 1613.94						
1613.94-5-V valve	L5	-1.520				
MP 1624.09 Coggins Rd	L5	-1.686				
MP 1633.66 Beaver Rd	L5	-1.628	-0.655			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 10/18 – 22/04

Unit: UNIT #295 BAY CITY

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1636.70 Bay City Station						
Rectifier				15.30	12.53	
1636.70-5-V valve	L5	-1.483				
5-SSV-1 valve	L5	-1.434				
Receiving Trap	L5	-1.753				
Launching Trap	L5	-1.852				
PCV piping		-1.798				
5-UDV-41 valve	L5	-1.242				
5-USV-31 valve	L5	-1.120				
5-UDV-11 valve	L5	-1.157				
MP 1642.09 3 Mile Rd	L5	-1.297	-0.835			
MP 1652.17 Finn Rd	L5	-1.615				
MP 1653.94	L5	-1.228	-1.151			
M/L BV	L5	-1.363				
MP 1660.19 Reese Rd	L5	-1.243				
MP 1669.99						
1669.99-5-V valve	L5	-1.269				
MP 1679.79 Swaffer Rd	L5	-1.529				
MP 1685.96 North Branch						
Station						
Rectifier				7.70	6.81	
5-USV-31 valve	L5	-1.243				
5-SSV-1 valve	L5	-1.558				
1685.96-5-V valve	L5	-1.679				
PCV piping	L5	-1.197				
MP 1694.10 Burnside Rd	L5	-1.201	-0.628			
MP 1704.74						
1704.74-5-V valve	L5	-1.086				
MP 1712.21 Metcalf Rd	L5	-1.184	-0.616			
MP 1721.43						
1721.43-5-V valve	L5	-1.131				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	ENBRIDGE ENERGY	**Date(s):**	10/18 – 22/04
Unit:	UNIT #295 BAY CITY		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 1727.59						
1727.59-5-V valve	L5	-1.406				
Rectifier	L5			8.08	6.20	
MP 1730.00	L5	-1.243	-0.632			
MP 1735.06						
1735.06-5-V valve	L5	-0.984				
MP 751.20						
751.2-6-V valve	L6B	-1.010				
MP 1732.07 (on L5)						
Marysville Delivery Station						
151-DELV-2 valve		-1.191				
Meter skid piping	L5	-1.251				
Meter skid piping	L6B	-1.242				
Prover piping	L5	-1.302				
Prover piping	L6B	-1.286				
151-CSV-121	L5	-1.037				
152-CSV-121	L6B	-0.967				
PCV piping	L5	-1.001				
PCV piping	L6B	-1.025				
MP 740.14 Palms Rd	L6B	-1.358	-0.661			
MP 735.58						
735.58-6-V valve	L6B	-1.241				
MP 726.74 Coon Creek Rd	L6B	-1.267				
MP 714.20 Leonard						
Station (inactive)						
714.2-6-V valve	L6B	-1.518				
Rectifier				10.10	7.74	
MP 701.14 Ortonville						
Station (inactive)						
Rectifier				12.50	6.96	
701.14-6-V valve	L6B	-1.822				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 10/18 – 22/04

Unit: UNIT #295 BAY CITY

	Line	Field Readings				
		CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
MP 688.97 Heskill Rd	L6B	-1.220				
MP 678.70 Howell Station						
6-USV-21 valve	L6B	-1.756				
6-USV-31 valve	L6B	-1.592				
6-UDV-41 valve	L6B	-1.235				
6-PCV-2 valve	L6B	-1.025				
678.70-6-V valve	L6B	-1.475				
Rectifier				22.60	3.99	
MP 674.21 Clyde Rd	L6B	-1.184	-0.633			
MP 668.69 Byron Rd	L6B	-1.234	-0.640			
MP 661.39 Fowler						
Station (inactive)						
Rectifier				23.60	3.45	
661.39-6-V valve	L6B	-1.352				
MP 656.57 Kane Rd	L6B	-1.344				
MP 651.54 Swan Rd	L6B	-1.467	-0.627			
MP 20. 63 Madden Rd						
20.63-17-V valve	L17	-2.000				
Rectifier				7.10	2.46	
MP 31.90 Waters Rd	L17	-1.953				
MP 35.80 Freedom Jct.						
Rectifier				4.50	0.84	
MP 45.06 Willow Rd	L17	-2.100	-0.564			
MP 49.31 Britton Station						
M/L piping	L17	-1.531				
MP 58.65 Totten Rd	L17	-1.014	-0.938			
MP 62.29 M/L BV	L17	-0.906				
MP 72.03 Erie Rd - Rectifier	L17	-1.598	-1.026	30.30	14.40	
MP 81.00 Manhattan Rd	L17	-0.943	-0.748			
MP 87.00 Cedar Point Rd	L17	-1.658				
MP88.00 Rectifier	L17			6.80	6.57	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 9/13 – 17/04

Unit: UNIT #295 BAY CITY

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 650.58 Stockbridge						
Station						
L6B incoming		-1.681				
L6B loop		-1.707				
6-UDV-11 valve		-1.505				
6-UDV-41 valve		-1.654				
Tank 80	N	-4.000				
	S	-5.600				
	E	-6.000				
	W	-5.300				
Line to Toledo @ launcher		-2.200				
L6/L17 XV valve		-1.066				
PCV		-4.000				
MP 638.45 M/L BV						
638.45-6-V valve		-1.338				
Bond box	L6B	-1.392				
	L6B loop	-1.396				
MP 633.66 M/L BV - East						
Side of Grand River						
633.66-6-V valve		-1.150				
MP 625.91 Crawford		-1.140	-0.613			
MP 621.00 Albion Station						
Rectifier				31.70	6.00	
620.66-6-V valve		-1.361				
MP 614.32 I-94			-0.522			
MP 613.32 Michigan Ave		-1.156	-0.750			
MP 610.61 M/L BV						
610.61-6-V valve		-1.474				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	ENBRIDGE ENERGY	**Date(s):**	9/13 – 17/04
Unit:	UNIT #295 BAY CITY		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 608.00 Marshall Station						
Rectifier				21.10	8.00	
PCV piping		-1.776				
6-UDV-31 valve		-1.625				
6-USV-21 valve		-1.353				
6-SSV-1 valve		-1.468				
607.63-6-V valve		-1.437				
MP 598.50 7.5 Mile Rd		-1.474	-0.549			
L6B loop line		-1.464				
MP 587.35 W Ave		-1.234	-0.605			
MP 578.07 Michigan Rd		-1.254	-0.551			
MP 562.22 Hoffman St.		-1.399	-1.156			
MP 552.94 Vandalia						
Station (inactive)				16.90	4.47	
552.94-6-V valve		-1.307				
MP 545.63 Mullen Rd		-2.300				
Rectifier				22.60	5.94	
MP 538.15 Niles Station						
Rectifier				44.00	8.00	
6-PCV-1 valve		-2.200				
6-UDV-41 valve		-6.600				
6-USV-31 valve		-2.800				
6-USV -11 valve		-1.549				
538.20-6-V valve		-1.086				
6-SDV-1 valve		-1.702				
538.15-6-V valve		-1.837				
MP 532.74 M/L BV						
532.74-6-V valve		-1.643				
MP 522.75 Snowberry Rd		-1.664	-0.445			
MP 519.70 Rectifier				14.80	7.20	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	ENBRIDGE ENERGY	**Date(s):**	
Unit:	UNIT #1282 GRIFFITH		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 499.00 La Porte Station						
Rectifier				68.60	6.50	
6-UDV-41 valve		-1.681				
6-USV-31 valve		-2.400				
6-USV-11 valve		-2.600				
Sump tank		-2.400				
PCV valve		-1.890				
6-SSV-1 valve		-1.194				
499.39-6-V valve		-0.993				
MP 489.14						
Rectifier				9.00	4.15	
Mainline TS		-1.146				
MP 474.97 M/L BV		-1.439				
Hartsdale Terminal						
Tank manifold area		-1.766				
Tank 1609	N	-3.600				
	S	-3.700				
	E	-3.100				
	W	-2.600				
Tank 1601	N	-2.800				
	S	-2.500				
	E	-4.300				
	W	-3.200				
Tank 1606	N	-3.400				
	S	-2.200				
	E	-3.400				
	W	-3.900				
MP 465.00 Griffith Station						
Tank 71	N	-2.200				
	S	-3.200				
	E	-2.700				
	W	-3.000				
	C	-1.535				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):**

Unit: UNIT #1282 GRIFFITH

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
Griffith Station (cont.)						
Rectifier 465A				11.30	14.60	
Tank 78	N	-4.300				
	S	-3.400				
	E	-3.100				
	W	-2.900				
Rectifier 465E				15.80	16.14	
Tank 75	N	-3.300				
	S	-3.600				
	E	-2.700				
	W	-3.500				
	C	-1.537				
Rectifier 465C				11.50	30.40	
Station manifold area						
L6A V720		-1.394				
L6B V721		-1.420				
L6B Area						
PCV piping		-1.013				
6-UDV-41 valve		-1.005				
6-UDV-21 valve		-0.996				
6-USV-11 valve		-0.953				
6B meter run		-1.305				
6B trap		-1.501				
6A trap		-1.585				
Relief skid area		-1.612				
465.39-6-V valve		-1.380				
Rectifier 465F				23.10	2.45	
MP 456.02 M/L BV		-1.463				
MP 451.82 S. Orchard St	L6A	-1.687	-0.789			
MP 442.19 St. Francis Rd		-1.094	-0.858			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):**

Unit: UNIT #1282 GRIFFITH

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
MP 438.00 Mokena Station						
Rectifier 461				5.50	7.86	
PCV piping		-1.154				
L6/L14 XV valve		-1.079				
Unit #1 piping		-0.883				
Unit #2 piping		-0.923				
Relief piping		-1.279				
L6A prover area		-1.515				
L14 incoming area		-1.547				
L14 relief valve piping		-1.393				
L6 meter bldg piping		-1.440				
MP 431.17 Crème Rd	L6A	-1.115	-1.033			
MP 426.00 Lockport Station						
Rectifier C427				15.20	15.15	
6-SSV-1 valve		-1.453				
6-SDV-1 valve		-1.353				
6A meter run		-1.833				
Sump Tank		-1.342				
6-USV-11 valve		-1.312				
6-UDV-21 valve		-1.258				
6-UDV-41 valve		-1.297				
PCV piping		-1.344				
MP 425.44 Canal Pipe Arch						
Active line		-1.461				
Counter balance line		-1.393				
Rectifier C425B				4.40	1.12	
MP 423.02 Normatown Rd						
M/L BV 423.02-6-V		-0.802				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 09/13 – 17/04

Unit: UNIT #1343 FORT ATKINSON

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 383.16 Dundee Station						
Rectifier				15.60	5.60	
383.16-6-V valve		-2.200				
PCV piping		-2.200				
6-UDV-41 valve		-1.897				
6-USV-31 valve		-1.184				
6-USV-11 valve		-1.050				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 09/20 – 24/04

Unit: UNIT #1343 FORT ATKINSON

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 99.16 Ladysmith Station						
Rectifier				19.00	7.00	
99.10-14-V valve	L14	-1.730				
99.25-6-BV valve	L6A	-1.362				
6-SDV-1 valve	L6A	-1.322				
Pump House piping	L6A	-1.707				
MP 110.02						
Rectifier				22.00	5.35	
110.02-14-V valve	L14	-1.749				
MP 123.46						
Rectifier				33.80	12.00	
124.18-14-V valve	L14	-1.973				
124.40-6-V valve	L6A	-1.820				
MP 131.70 Taylor Rd	L6A	-1.578				
	L14	-1.655				
MP 135.53 Lublin Station						
Rectifier				14.80	15.70	
Pump House piping		-2.400				
135.55-6-BV valve	L6A	-1.450				
135.42-14-V valve	L14	-1.814				
MP 142.70 County Rd X	L6A	-1.753	-0.660			
	L14	-1.705				
MP 148.54 Owen Station						
Rectifier				18.40	18.90	
148.78-6-BV valve	L6A	-1.293				
PCV piping	L6A	-1.142				
6-UDV-41 valve		-1.447				
6-USV-31 valve		-1.326				
6-USV-21 valve		-1.452				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 09/20 – 24/04

Unit: UNIT #1343 FORT ATKINSON

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 148.54 Owen Station	(cont.)					
6-USV-11 valve	L6A	-1.669				
Piping @ I.F.	L14	-1.771				
MP 157.87 Division Lane	L6A	-1.630				
	L14	-1.678				
MP 161.10						
Rectifier				17.90	5.95	
	L6A	-3.000				
	L14	-3.500				
MP 165.83						
165.80-6-V valve	L6A	-1.418				
MP 173.29 Marshfield						
Station						
Rectifier C173B				13.30	13.85	
Rectifier C173A				44.30	13.20	
173.29-14-V valve	L14	-1.621				
6-SSV-1 valve	L6A	-1.163				
Pump House piping		-1.444				
MP 179.03 Puff Creek Blvd.	L6A	-1.721				
	L14	-1.903				
MP 184.90 County Rd C	L6A	-1.595	-0.642			
	L14	-1.596				
MP 193.63 Vesper Station						Rectifier shut down due to construction.
MP 201.00 Rectifier				80.20	14.90	
MP 201.20						
201.20-6-V valve	L6A	-2.300				
201.15-14-V valve	L14	-1.978				
MP 203.30 Wisconsin						
River – South side						
203.30-6-V valve	L6A	-1.495				
203.08-14-V valve	L14	-1.036				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 09/20 – 24/04

Unit: UNIT #1343 FORT ATKINSON

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 211.64 State Hwy 13						
Rectifier				87.40	26.20	
	L6A	-13.400				
	L14	-13.800				
MP 216.24 Brown Peer Rd	L6A	-1.134	-0.882			
	L14	-2.100				
MP 222.75 Cypress Ave.	L6A	-2.000				
	L14	-1.788				
MP 227.52 Adams Station						
Rectifier				47.20	13.00	
227.56-6-TRV valve	L6A	-4.200				
Receiving trap	L6A	-13.100				
Launching trap	L6A	-12.000				
6-SDV-1 valve	L6A	-3.100				
PCV piping		-2.300				
6-UDV-41 valve	L6A	-1.815				
6-USV-31 valve	L6A	-1.738				
Sump Tank		-2.300				
6-USV-11 valve	L6A	-1.900				
L14 Receiver area	L14	-7.300				
L14 Launcher area	L14	-4.900				
Piping @ pump house		-1.544				
MP 235.87 1st Ave.	L6A	-1.925	-0.144			
	L14	-1.808				
MP 242.28						
242.28-14-V valve	L14	-1.033				
	L6A	-1.068	-0.347			
MP 250.09 I-39/USS1						
Rectifier				58.40	15.20	
	L6A	-3.700	-0.636			
	L14	-4.400				
MP 257.11 Wilcox Rd	L6A	-2.200	-0.779			
	L14	-2.300				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 09/20 – 24/04

Unit: UNIT #1343 FORT ATKINSON

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 259.59						
Rectifier				54.20	6.10	
MP 266.88 Waters Rd	L6A	-1.593	-0.397			
	L14	-1.594				
MP 270.77 CMSP/P RR	L6A	-1.004	-0.346			
	L14	-0.974	-0.974			Operator will develop plan of action for shorted casing.
MP 277.65 County Rd A	L6A	-1.367	-0.823			
	L14	-1.544				
MP 287.74 County Rd TT	L6A	-1.705	-0.976			
	L14	-1.695				
MP 292.00						
Rectifier				19.00	8.30	
292.64-6-BV valve	L6A	-2.100				
Piping @ pump house		-3.800				
MP 304.58 Cambridge						
Station						
Rectifier				11.10	4.74	
304.58-6-V valve	L6A	-1.261				
Valve outside pump house	L14	-1.990				
PCV piping	L6A	-2.100				
6-UDV-41 valve	L6A	-14.17				
6-USV-31 valve	L6A	-3.000				
6-USV-21 valve	L6A	-2.800				
6-USV-11 valve	L6A	-3.000				
MP 312.52 Rock River						
West side						
312.52-6-V-1 valve	L6A	-1.040				
14-312.32-V valve	L14	-1.047				
MP 313.40 Rock River						
East side						
14-313.40-V valve	L14	-0.950				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	ENBRIDGE ENERGY	**Date(s):**	09/20 – 24/04
Unit:	UNIT #1343 FORT ATKINSON		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 317.94 County Line Rd	L6A	-1.262	-0.601			
	L14	-1.284				
MP 321.33 Delavan Station						
Rectifier				12.10	1.85	
321.33-6-V valve	L6A	-1.169				
Piping outside pump house		-1.721				
MP 326.81 Lake Lorraine Rd	L6A	-1.233	-0.572			
	L14	-1.223				
MP 333.74						
	L6A	-2.700	-0.486			
333.64-14-V valve	L14	-2.100				
MP 340.00 Walworth Station						Rectifier shut down for construction and hydro test.
MP 348.35 Wright Rd	L6A	-1.688	-0.684			
	L14	-1.428				
MP 352.53						
Valve	L6A	-1.968				
MP 352.33						
352.33-14-V valve	L14	-1.792				
MP 363.11 Ridge Rd	L6A	-1.638	-0.526			
MP 368.10 Crystal Lake						
Station						
Rectifier				28.90	15.80	
368.10-6-BV valve	L6A	-1.884				
Piping outside pump house		-1.936				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company:	ENBRIDGE ENERGY	**Date(s):**	09/13 – 17/04
Unit:	UNIT #1282 GRIFFITH		

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 499.00 La Porte Station						
Rectifier				68.60	6.50	
6-UDV-41 valve		-1.681				
6-USV-31 valve		-2.400				
6-USV-11 valve		-2.600				
Sump tank		-2.400				
PCV valve		-1.890				
6-SSV-1 valve		-1.194				
499.39-6-V valve		-0.993				
MP 489.14						
Rectifier				9.00	4.15	
Mainline TS		-1.146				
MP 474.97 M/L BV		-1.439				
Hartsdale Terminal						
Tank manifold area		-1.766				
Tank 1609	N	-3.600				
	S	-3.700				
	E	-3.100				
	W	-2.600				
Tank 1601	N	-2.800				
	S	-2.500				
	E	-4.300				
	W	-3.200				
Tank 1606	N	-3.400				
	S	-2.200				
	E	-3.400				
	W	-3.900				
MP 465.00 Griffith Station						
Tank 71	N	-2.200				
	S	-3.200				
	E	-2.700				
	W	-3.000				
	C	-1.535				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 09/13 – 17/04

Unit: UNIT #1282 GRIFFITH

Line & Location	Line Size, in.	Field Readings CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
Griffith Station (cont.)						
Rectifier 465A				11.30	14.60	
Tank 78	N	-4.300				
	S	-3.400				
	E	-3.100				
	W	-2.900				
Rectifier 465E				15.80	16.14	
Tank 75	N	-3.300				
	S	-3.600				
	E	-2.700				
	W	-3.500				
	C	-1.537				
Rectifier 465C				11.50	30.40	
Station manifold area						
L6A V720		-1.394				
L6B V721		-1.420				
L6B Area						
PCV piping		-1.013				
6-UDV-41 valve		-1.005				
6-UDV-21 valve		-0.996				
6-USV-11 valve		-0.953				
6B meter run		-1.305				
6B trap		-1.501				
6A trap		-1.585				
Relief skid area		-1.612				
465.39-6-V valve		-1.380				
Rectifier 465F				23.10	2.45	
MP 456.02 M/L BV		-1.463				
MP 451.82 S. Orchard St	L6A	-1.687	-0.789			
MP 442.19 St. Francis Rd		-1.094	-0.858			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY

Date(s): 09/13 – 17/04

Unit: UNIT #1282 GRIFFITH

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	**Size, in.**	**P/S**	**Casing**	**Volts**	**Amps**	**Remarks**
MP 438.00 Mokena Station						
Rectifier 461				5.50	7.86	
PCV piping		-1.154				
L6/L14 XV valve		-1.079				
Unit #1 piping		-0.883				
Unit #2 piping		-0.923				
Relief piping		-1.279				
L6A prover area		-1.515				
L14 incoming area		-1.547				
L14 relief valve piping		-1.393				
L6 meter bldg piping		-1.440				
MP 431.17 Crème Rd	L6A	-1.115	-1.033			
MP 426.00 Lockport Station						
Rectifier C427				15.20	15.15	
6-SSV-1 valve		-1.453				
6-SDV-1 valve		-1.353				
6A meter run		-1.833				
Sump Tank		-1.342				
6-USV-11 valve		-1.312				
6-UDV-21 valve		-1.258				
6-UDV-41 valve		-1.297				
PCV piping		-1.344				
MP 425.44 Canal Pipe Arch						
Active line		-1.461				
Counter balance line		-1.393				
Rectifier C425B				4.40	1.12	
MP 423.02 Normatown Rd						
M/L BV 423.02-6-V		-0.802				

2004 Chicago Region Field Audit Participants

Week of September 13 -17, 2004   Stockbridge Michigan – Dundee Illinois

Stockbridge Station
- Kent Nikel (Engineering)
- Tim Hunlock (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Marshall Station
- Pete Weston (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Niles Station
- Darrell Carter (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

LaPorte Station
- Richard Widlowski (Electrical Technician)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Hartsdale Terminal
- Garry Thompson (Terminal Supervisor)
- Tom Sims (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Griffith Terminal
- Garry Thompson (Terminal Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

2004 Chicago Region Field Audit Participants

Week of September 13 -17, 2004 continued **Stockbridge Michigan – Dundee Illinois**

Mokena Delivery
- Andy Schmitz (Electrical Technician)
- Chuck Weisbrodt (Delivery Gauger)
- Tom Sims (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Lockport Station
- Dave Czarny (Electrical Technician)
- Tom Sims (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Dundee Station
- Mike Lange (Electrical Technician)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Week of September 20 -24, 2004 **Ladysmith Wisconsin – Crystal Lake Illinois**

Ladysmith Station
- Jim Sojka (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Lublin Station
- Jim Sojka (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Owen Station
- Kurt Castle (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

2004 Chicago Region Field Audit Participants

Week of September 20 -24, 2004 cont. **Ladysmith Wisconsin – Crystal Lake Illinois**

Marshfield Station
- Kurt Castle (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Vesper Station
- Mike Kinney (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Adams Station
- Pete Olson (Electrical Technician)
- Nick Srock (Mechanical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Waterloo Station
- Mike Monson (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Cambridge Station
- Mike Monson (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Delavan Station
- Jim Jacobson (Electrical Technician)
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

2004 Chicago Region Field Audit Participants

Week of September 20 -24, 2004 cont. **Ladysmith Wisconsin – Crystal Lake Illinois**

Walworth Station
- Electrical Technician was sent home sick
- Steve Ott (Technical Supervisor)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Crystal Lake Station
- Mike Lange (Electrical Technician)
- Jay Johnson (Compliance)
- Raymond Wyckoff (Corrosion)
- Marc Curry (Safety Coordinator)

Week of October 18 -22, 2004 **Lewiston Michigan – Oregon Ohio**

Lewiston Station
- Ken Ulreich (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- John Bissell (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

West Branch Station
- Ken Ulreich (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- John Bissell (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

Bay City Station
- Ken Ulreich (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- John Bissell (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

2004 Chicago Region Field Audit Participants

Week of October 18 -22, 2004 continued   Lewiston Michigan – Oregon Ohio

North Branch Station
- Lynn Bunker (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- John Bissell (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

Marysville Delivery
- Ron Cook (Delivery Gauger)
- Lynn Bunker (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- John Bissell (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

Howell Station
- Dennis Esterline (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- Raymond Wyckoff (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

Fowler Station
- Dennis Esterline (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- Raymond Wyckoff (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)
-

Wolverine Records review
- Raymond Wyckoff (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)
- Fred Hipshear (ROW agent – Wolverine)
- Russell Carson (Corrosion Technician – Wolverine)
- Dave Rew (Area Engineer – Wolverine)

2004 Chicago Region Field Audit Participants

Week of October 18 -22, 2004 continued Lewiston Michigan – Oregon Ohio

Britton Station

- Dennis Esterline (Electrical Technician)
- Jarrett Kachur (Technical Supervisor)
- Raymond Wyckoff (Corrosion Technician)
- Jay Johnson (Compliance)
- Marc Curry (Safety Coordinator)
- Roy Maye (Guest- Cushing Region Safety Coordinator)

10.25.04
JT.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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.** Refer to the last page of this form for **PIM** example entries.

RW Smallcomb 10-18-04

Inspection Report		Post Inspection Memorandum	
Inspector/Submit Date:	**C. P. Goetz/J. T. Williams June 21-23, 2004; July 27, 2004**	**Inspector/Submit Date:**	J.T. Williams 6/30/04
		Peer Review/Date:	7/28/04 C. P. Goetz 11/4/04
		Director Approval/Date:	11/5/04

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator: Enbridge Energy		**OPID #:**	11169
Name of Unit(s): Lakehead-Tonawanda		**Unit # (s):**	1611
Records Location: Tonawanda			
Unit Type & Commodity: Hazardous Liquid-Crude Oil			
Inspection Type: Unit Inspection		**Inspection Date(s):**	June 21-23, 2004
OPS Representatives): OPS-Robert Smallcomb; NYS DPS C.P. Goetz and J.T. Williams		**AFO Days:**	4.5

Summary:
We conducted an inspection of Enbridge's Unit #1611 on June 21-23, 2004. The unit consists of 20 miles of coated protected 12" steel pipeline and a pump station. The inspection included a records and facilities review as well as a unit employee OP/Qual. Review and inspection of the Tonawanda Pump Station. The types of reviews we conducted are documented in the evaluation report. We found all records were organized and readily available. We evaluated OP/Qual. Databases for company employees, contract welders, and abnormal operating conditions and incidents. Our field review verified a highly acceptable level of employed knowledge.

Findings:
We found no instances of probable non-compliance nor did we identify any areas of concern.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

10-22-

Name of Operator: Enbridge Energy	
H.Q. Address: Enbridge Energy 1100 Louisiana Suite 3200 Houston, TX 77002	**System/Unit Address:** Chicago Region Line 10 Two Mile Creek Road Tonawnada, NY 14150
Co. Official: Dan Tutcher, President **Phone No.:** 713-650-8900 **Fax No.:** 713-653-6711 **Emergency Phone No.:** 800-858-5253	**Activity Record ID#:** **Phone No.:** 716-692-0091 **Fax No.:** **Emergency Phone No.:** 800-858-5253

Persons Interviewed	Titles	Phone No.
George Barth	Senoir Technician	716-692-0091
Jay Johnson	Compliance Coordinator	715-394-1512
Marc Curry	Compliance Coordinator	219-922-3133 ext 225
Kimberly Joy Harris	Corrosion Technician	219-775-7315
Steve Sleever	Project Manager	920-723-8824

Company System Maps (copies for Region Files): On file in the Buffalo Office

Unit Description:

Consists of approximately 20 miles of 12" coated protected steel pipe and one pump station.

Portion of Unit Inspected *(not required if covered in the PIM)*:

This was a standard inspection which included a review of inspection records as well as field inspections. O&M procedures are not included in a standard inspection and were not included in this review.

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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CONVERSION TO SERVICE		S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
.402(a) .402(c) (2)		Procedures for gathering data needed for reporting accidents in a timely and effective manner.				x
	.50	Accident report criteria, as detailed under 195.50. A release of 5 gals or more may be required to be reported.				x
	.52	Telephonically reporting accidents to **NRC (800) 424-8802**				x
	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery				x
	.54(b)	Supplemental report - required within 30 days of information change/addition				x
	.55	Safety-related conditions (SRC) - criteria				x
	.56(a)	SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery				x
	.56(b)	SCR Report requirements, including corrective actions (taken and planned)				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		SUBPART D - WELDING PROCEDURES	S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.						
.402(c)/ .422	**.214(a)**	Welding must be performed by qualified welders using qualified welding procedures.				x
		Welding procedures must be qualified by destructive testing.				x
	.214(b)	Each welding procedure must be recorded in detail, including results of qualifying tests.				x
		Are welding procedures qualified in accordance with a standard that is accepted by the industry? **(API 1104, ASME Boiler & Pressure Code - Section IX, or other)**				x
	.222(a)	Welders must be qualified in accordance with **Section 3 of the API Standard 1104 (18th Ed., 1994)** or **Section IX of the ASME Boiler and Pressure Vessel Code (1995)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition.				x
	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 6 of API 1104.				x
	Alert Notice 3/13/87	**In the welding of repair sleeves and fittings, do the operator's procedures give consideration to:**				
		1. The use of low hydrogen welding rods.				
		2. Cooling rate of the weld.				
		3. Metallurgy of the materials being welded (weldability carbon equivalent).				
		4. Proper support of the pipe in the ditch.				
.402(c)/ .422	**.226(a)**	Arc burns must be repaired.				x
	.226(b)	Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammon. Persulfate)**. Pipe must be removed for non-repairable notches.				x
	.226(c)	The ground wire may not be welded to the pipe/fitting being welded.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

		WELDS: ACCEPTABILITY - NONDESTRUCTIVE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	**.228 /.234**	Do procedures require welds to be nondestructively tested to insure their acceptability according to **Section 6 of API 1104 (18th)** and per the requirements of **§195.234** in regard to the number of welds to be tested?				x
	.234(b)	Nondestructive testing of welds must be performed:				
		1. In accordance with written procedures for **NDT**				x
		2. By qualified personnel				x
		3. By a process that will indicate any defects that may affect the integrity of the weld				x
	.266	Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		WELDS: REPAIR or REMOVAL of DEFECT PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	**.230**	Welds that are unacceptable (Section 6 API 1104) must be removed and/or repaired. See .228 and .230 for exceptions.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	**.302(a)**	Each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be pressure tested.				x
	.302(b)	Lines that have not been pressure tested per subpart E must be operated in accordance with Subpart E.				x
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195.303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				x
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				x
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines).				x
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).				x
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).				x
	.303	Procedures for the risk based alternative to pressure testing?				x
	.304	Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required.				x
	.305(a)	All pipe, all attached fittings, including components must be pressure tested in accordance with §195.302.				x
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				x
	.306	Appropriate test medium				x
	.308	Pipe associated with tie-ins must be pressure tested.				x
	.310(a)	Test records must be retained for useful life of the facility.				x
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				x
	.310(b)(2)	Test instrument calibration data.				x
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				x
	.310(b)(4)	Date and time of the test.				x
	.310(b)(5)	Minimum test pressure.				x
	.310(b)(6)	Test medium.				x

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SUBPART E - PRESSURE TESTING PROCEDURES (Con't)			S	U	N/A	N/C
.402(c)/ .422	**.310(b)(7)**	Description of the facility tested and the test apparatus.				x
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				x
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included				x
	.310(b)(10)	Temperature of the test medium or pipe during the test period.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	**.402**	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				x
		b. Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?				x
		c. Appropriate parts must be kept at locations where O&M activities are conducted.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
.402(a)	**.402(c)**	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				x
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				x
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				x
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				x
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?				x
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				x
	.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards.				x

MAINTENANCE & NORMAL OPERATION PROCEDURES (Con't)			S	U	N/A	N/C
		Reporting abandoned pipeline facilities under commercially navigable waterways per §195.59				x
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases?				x
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				x
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				x
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		I. Unintended closure of valves or shutdowns?				x
		ii. An increase or decrease in pressure or flow rate outside normal operating limits?				x
		iii Loss of communications?				x
		iv. The operation of any safety device?				x
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				x
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				x
	.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?				x
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				x
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				x

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STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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		EMERGENCY PROCEDURES	S	U	N/A	N/C
.402(a)	**.402(e)**	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				x
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				x
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				x
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				x
	.402(e)(5)	Controlling the release of liquid at the failure site?				x
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				x
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				x
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				x
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	S	U	N/A	N/C
.402(a)	**.403(a)**	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the emergency response procedures established under §195.402.				x
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				x
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				x
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				x
	.403(a)(5)	Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition.				x
	.402(f)	Instructions to enable O&M personnel to recognize and report potential safety related conditions.				x
	.403(b)	At intervals not exceeding 15 months, but at least once each calendar year:				
	.403(b)(1)	Review with personnel their performance in meeting the objectives of the emergency response training program				x
	.403(b)(2)	Make appropriate changes to the emergency response training program				x
	.403(c)	Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible.				x

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Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		MAPS and RECORDS PROCEDURES	**S**	**U**	**N/A**	**N/C**
.402(a)	**.402(c)(1)**	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				x
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				x
		ii. Pump stations				x
		iii. Scraper and sphere facilities				x
		iv. Pipeline valves				x
		v. Facilities to which **§195.402(c)(9)** applies				x
		vi. Rights-of-way				x
		vii. Safety devices to which **§195.428** applies				x
	.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				x
	.404(a)(3)	The maximum operating pressure of each pipeline.				x
	.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.				x
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				x
	.404(b)(2)	Any emergency or abnormal operation to which the procedures under **§195.402** apply.				x
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				x
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				x
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer.**				x

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		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
.402(a)	**.406(a)**	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1)	The internal design pressure of the pipe determined by **§195.106**.				x
	.406(a)(2)	The design pressure of any other component on the pipeline.				x
	.406(a)(3)	**80%** of the test pressure **(Subpart E)**.				x
	.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				x
	.406(a)(5)	**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				x
	.406(b)	The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations:				
		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
.402(a)	**.408(a)**	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.				x
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(1)	Monitoring operational data as required by **§195.402(c)(9)**.				x
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				x
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				x
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

		LINE MARKER PROCEDURES	S	U	N/A	N/C
.402(a)	**.410(a)**	Line markers must be placed over each buried pipeline in accordance with the following:				
	.410(a)(1)	Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known				x
	.410(a)(2)	Must have the correct characteristics and information				x
	.410(c)	Must be placed where pipelines are aboveground in areas that are accessible to the public				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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INSPECTION RIGHTS-of-WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
.402(a)	.412(a)	Operator must inspect the right-of-way at intervals not exceeding 3 **weeks**, but at least **26 times each calendar year**				x
	.412(b)	Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
.402(a)	.413(b)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator:				
	.413(b)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center.				x
	.413(b)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation.				x
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
.402(a)	.420(a)	Operator must maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times.				x
	.420(b)	Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year.				x
	.420(c)	Operator must provide protection for each valve from unauthorized operation and from vandalism.				x

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		PIPELINE REPAIR PROCEDURES	S	U	N/A	N/C
.402(a)	**.422(a)**	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property.				x
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
.402(a)	**.424(a)**	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**.				x
	.424(b)	For **HVL** lines **joined** by welding, the operator must:				x
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				x
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.				x
	.424(b)(3)	Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				x
	.424(c)	For **HVL** lines **not joined** by welding, the operator must:				x
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				x
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.				x
	.424(c)(3)	Isolate the line to prevent flow of the **HVL**.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
.402(a)	**.426**	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres.				x
		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
.402(a)	.428(a)	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable.				x
		Operator must inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				x
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.				x
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years.**				x
	.428(c)	Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to the appropriate API. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				x
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

		FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C
.402(a)	.430	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas.				x
		The equipment must be:				
		a. In proper operating condition at all times.				x
		b. Plainly marked so that its identity as firefighting equipment is clear.				x
		c. Located so that it is easily accessible during a fire.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

		BREAKOUT TANK PROCEDURES	S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. **(annually/ 15mo)** includes anhydrous ammonia and any other breakout tank that is not inspected per **432 (b) & (c)**; (Reference 195.1)				x
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to **section 4 of API Standard 653.** However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under **§195.402(c)(3).**				x
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to **API Standard 2510** according to **section 6 of API 510.**				x

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BREAKOUT TANK PROCEDURES (Con't)			S	U	N/A	N/C
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on **May 3, 1999**, or on the operator's last recorded date of the inspection, whichever is earlier.				x
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

SIGN PROCEDURES			S	U	N/A	N/C
.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.				x
		Signs must contain the name of the operator and a telephone number where the operator can be reached at all times.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

SECURITY of FACILITY PROCEDURES			S	U	N/A	N/C
.402(a)	.436	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

SMOKING OR OPEN FLAME PROCEDURES			S	U	N/A	N/C
.402(a)	.438	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

PUBLIC EDUCATION PROCEDURES			S	U	N/A	N/C
.402(a)	.440	Is there a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				x
		Is the program conducted in English and other languages where appropriate?				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				x
	.442(b)	Does the operator participate in a qualified One-Call program?				x
	.442(c)(1)	Include the identity, on current a basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				x
	.442(c)(2)	~~Provide for notification to the public in the vicinity of the pipeline and actual notification to the~~ persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		I. The program's existence and purpose.				x
		ii. How to learn the location of underground pipelines before excavation activities are begun.				x
	.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.				x
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				x
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				x
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		I. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.				x
		ii. In the case of blasting, any inspection must include leakage surveys.				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

		CPM/LEAK DETECTION PROCEDURES	S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				x

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES		S	U	N/A	N/C
§195.452	This form does not cover Liquid Pipeline Integrity Management Programs				x

SUBPART G - OPERATOR QUALIFICATION PROCEDURES	S	U	N/A	N/C

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§195.501-509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				x

		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
.402(a)	.555	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.				x
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				x
		a) constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**				x
		b) Converted under **195.5** and 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;				x
		2) Is a segment that is relocated, replaced, or substantially altered.				x
	.559	**Coating Materials;** Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				x
	.561	a. All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				x
		b. All coating damage discovered must be repaired.				x
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year?**				x
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or				x
		2) Is a segment that is relocated, replaced, or substantially altered.				x
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				x
		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				x
		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.				x
	.567	Test leads installation and maintenance				x

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		SUBPART H - CORROSION CONTROL PROCEDURES (Con't)	S	U	N/A	N/C
.402(a)	.569	Examination of Exposed Portions of Buried Pipelines				x
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-96** (incorporated by reference)				x
	.573	a. (1) Pipe to soil monitoring **(annually / 15months)**				x
		Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**				x
		(2) **Before 12/29/2003 or not more than 2 years** after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE RP0169-96.**				x
		b. ~~Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas~~ in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment.				x
		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.**				x
		Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months.**				x
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2½ mos.**				x
		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b).**				x
	.575	Are there adequate provisions for electrical isolations?				x
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects? b. Design & install CP systems to minimize effects on adjacent metallic structures.				x
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken?				x
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion				x
		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**				x
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe.				x
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement)				x
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least **once every 3 years but at intervals not exceeding 39 months.**				x
		OFFSHORE - At least **once each year, but at intervals not exceeding 15 months.**				x
	.585	a. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness?				x
		b. Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness?				x
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)**				x
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**; Some are for the **service life**)				x

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Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*

Best Practice:

What process does the Operator have to address Alert Notices?

Comments: Accessing OPS website

Best Practice: Stress Corrosion Cracking
Pipeline Safety Advisory Bulletin ADB-03-05 - October 8, 2003
Reference http://www.gpoaccess.gov/fr/advanced.html **fr06oc03N Pipeline** Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Liquid Pipelines).

Is the operator aware of the bulletin, and is the operator reviewing their system for the potential of SCC?
Y/N **y SCC is an extensive part oft heir IMP analysis and monitoring**

Best Practices: Damage Prevention
(If operator's damage prevention best practices answers have not changed since the previous inspection and are noted as such, then completion of the below 7 questions is not required).

1. Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities? Y/N y

2. Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors? Y/N y

3. Does the operator's damage prevention program include proactive liaison with local school officials, where transmission pipelines traverse or are adjacent to school property? Y/N y

4. Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices? Y/N y

5. Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan? Y/N y

6. Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study? Y/N y

7. Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices? Y/N y

Damage Prevention Comments: **Operator is actively involved with the one call system through the local damage prevention council, closely monitors work near their pipeline and works with the local public officials.**

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Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

PART 195 - FIELD REVIEW		S	U	N/A	N/C
.120	Have new pipelines, or pipeline sections of which pipe or components have been replaced, been designed and constructed to accommodate smart pigs ? (See exceptions under (b) and (c))	1			
.262	Pumping Stations	2			
.262	Station Safety Devices	3			
.308	Pre-pressure Testing Pipe - Marking and Inventory			4	
.403	Emergency Response Training				5
.410	Right-of-Way Markers	6			
.412	River Crossings				7
.557	Cathodic Protection (test station readings, other locations to ensure adequate CP) levels)	8			
.573	Pipeline Components Exposed to the Atmosphere	9			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	8			
.420	Valve Maintenance				10
.420	Valve Protection from Unauthorized Operation and Vandalism	11			
.426	Scraper and Sphere Facilities and Launchers	12			
.428	Pressure Limiting Devices				13
.428	Relief Valves - Location - Pressure Settings - Maintenance				13
.428	Pressure Controllers				13
.430	Fire Fighting Equipment	14			
.432	Breakout Tanks			15	
.434	Signs - Pumping Stations - Breakout Tanks	16			
.436	Security - Pumping Stations - Breakout Tanks	17			
.438	No Smoking Signs	18			
.501-.509	Operator Qualification Questions - See Attachment 3				19

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Unless otherwise noted, all code references are to Part 195 S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION to SERVICE				
.5(a)(1)	Testing to Verify MOP (ASME<Appendix N)			20	
.5(a)(2)	Inspection of Pipeline Right-of-Way			20	
.5(c)	Pipeline Records (Life of System)			20	
	Pipeline Investigations			20	
	Pipeline Testing			20	
	Pipeline Repairs			20	
	Pipeline Replacements			20	
	Pipeline Alterations			20	
	REPORTING				
.49	Annual Report (DOT form RSPA F7000-1.1Beginning no later than June 15, 2005)	21			
.52	Telephonic Reports to NRC (800-424-8802)			22	
.54(a)	Written Accident Reports (DOT Form 7000-1)			22	
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)			22	
.56	Safety Related Conditions			22	
.57	Offshore Pipeline Condition Reports			23	
.59	Abandoned Underwater Facility Reports			23	
	CONSTRUCTION				
.204	Construction Inspector Training/Qualification	24			
.214(b)	Test Results to Qualify Welding Procedures				25
.222	Welder Qualification	24			
.234(b)	Nondestructive Technician Qualification	24			
.589	Cathodic Protection	26			
.266	Construction Records				27
.266(a)	Total Number of Girth Welds				27
	Number of Welds Inspected by NDT				27
	Number of Welds Rejected				27
	Disposition of each Weld Rejected				27
.266(b)	Amount, Location, Cover of each Size of Pipe Installed				27
.266(c)	Location of each Crossing with another Pipeline				27
.266(d)	Location of each buried Utility Crossing				27
.266(e)	Location of Overhead Crossings				27
.266(f)	Location of each Valve and Test Station				27
	PRESSURE TESTING				
.310	Pipeline Test Record	28			
.305(b)	Manufacturer Testing of Components				29
.308	Records of Pre-tested Pipe			30	

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Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

	PART 195 - RECORDS REVIEW (Con't.)	S	U	N/A	N/C
	OPERATION & MAINTENANCE				
.402(a)	Annual Review of O&M Manual (**1 per yr/15 months**)	31			
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	32			
.402(c)(10)	Abandonment of Facilities				33
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Public Officials	34			
.402(c)(13)	Review of work Performed by Personnel (periodically)	35			
.402(d)(1)	Response to Abnormal Pipeline Operations	36			
~~.402(d)(5)~~	~~Review of Personnel Response to Abnormal Operations~~	36			
.402(e)(1)	Notices of Emergencies	37			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	37			
.402(e)(9)	Post Accident Reviews	38			
.403(a)	Emergency Response Personnel Training Program	39			
.403(b)	Review of Personnel Perform., Emergency Response Program Changes (**1 per yr/15 months**)	39			
.403(c)	Verification of Supervisor Knowledge - Emergency Response Procedures	39			
.404(a)(1)	Maps or Records of Pipeline System	40			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	40			
.404(a)(3)	MOP of each Pipeline	41			
.404(a)(4)	Pipeline Specifications	41			
.404(b)(1)	Pump Station Daily Discharge Pressure (maintain for at least 3yrs)	42			
.404(b)(2)	Abnormal Operations (§195.402) (maintain for at least 3yrs)	43			
.404(c)(1)	Pipe Repairs (maintain for useful pipe life)	44			
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr)	22			
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	45			
.406(a)	Establishing the MOP	41			
.412(a)	Inspection of the ROW	46			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	47			
.413(b)	Inspection of Pipelines in Gulf of Mexico			48	
.420(b)	Inspection of Mainline Valves	49			
.428(a)	Insp. of Overpress. Safety Devices (**1 per yr/15 months** non-hvl; **2 per yr/7½ months** hvl)	50			
.428(b)	Inspection of Relief Devices on HVL Tanks (intervals NTE **5 yrs**).			51	
.428(d)	Inspection of Overfill Systems (**1 per yr/15 months** non-hvl; **2 per yr/7½ months** hvl)			52	
.430	Inspection of Fire Fighting Equipment	14			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	15			
.440	Public Education	63			

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Unless otherwise noted, all code references are to Part 195 **S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked**

PART 195 - RECORDS REVIEW (Con't.)		S	U	N/A	N/C
DAMAGE PREVENTION PROGRAM					
.442(c)(1)	List of Current Excavators	53			
.442(c)(2)	Notification of Public/Excavators	53			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	53			
CORROSION CONTROL					
.569	Inspection of Exposed Pipelines (External Corrosion)	44			
.573(a)	External Corrosion Control - Protected Pipelines	54			
.573(b)	External Corrosion Control - Unprotected Pipelines			55	
.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	54			
.573(d)	External Corrosion Control - Bottom of Breakout Tanks			15	
.579(a)	Corrosive effect investigation	56			
.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment	56			
.579(c)	Inspection of Removed Pipe for Internal Corrosion	44			
.583(a)	Atmos. Corr. Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**	57			
.589	Cathodic Protection (Maps showing anode location, test stations, CP systems, etc)	58			

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note):*

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Oil Pollution Act High Impact Inspection (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	59		
194.111	RSPA Tracking Number: Approval Date:			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	60		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	61		
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	62		
194.117	~~Does the operator maintain records for spill response training (including Hazwoper training)?~~ [OPA-5]	~~62~~		

Comments *(If any of the above is marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note)*:

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators. If the operator is a new operator without a plan, the unit has a new owner, or the unit has new facilities not incorporated into the existing OPA-90 Plan, the answer is NO. Direct the operator to contact L.E. Herrick, 202-366-5523.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1
SCADA Liquid Worksheet

The topics on this worksheet regard general SCADA functionality. A more thorough SCADA evaluation may be warranted based on the results of this worksheet or prompts by other events.

1. **Pipeline Safety Advisory Bulletins (reference http://www.gpoaccess.gov/fr/advanced.html)**

   Review the following with the operator:

   • July 7, 1999 Advisory Bulletin ADB-99-03 (Ref.**fr16jy99N Potential Service Interruptions in Supervisory Control and Data Acquisition Systems**) - discuss SCADA system performance.

   • December 16, 2003 Advisory Bulletin ADB-03-09 (Ref. **fr23de03N Pipeline Safety: Potential Service Disruptions in Supervisory Control and Data Acquisition Systems**) – discuss consideration of possible SCADA system disruptions caused by system maintenance or upgrade.

Comments: Bulletins discussed with operator. Operator has redundant servers. The operator's CPU usage is normally in the range of 10% to 20%. The operator strives to maintain CPU usage at something less than 60%. A separate development work station is used for testing. Back-up system uses continuous current data so that there is no interruption in case a switch over is required. The operator's SCADA system has about 20 to 30 personnel to provide support and development.

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. **195.402(d)(1)(iii) - Loss of communications.**

   • Off-site Back-up Center
   • Data transfer to redundant or off-site processors
   • Battery and/or Emergency Generator
   • Redundant data communications paths, automatic restoration or manual?
   • Data Reduction & Archiving
   • Indication of stale, forced or manually overridden data, or system lock-up
   • Operating practices during data communications outages

Comments: Enbridge Energy has a back-up control center located in Superior, WI. The back-up center has 5 to 6 consoles and in the event that a console fails, any one of the other consoles can be used. If for any reason, the building housing the control center at Edmonton had to be evacuated, then the control center would shut-down all pipelines and personnel would temporarily relocate to another back-up control center at an Edmonton terminal that is approximately 15 to 20 minutes from the main control center. Control personnel would then begin a systematic re-start of all pipelines. Back-up control centers are tested a minimum of two times per year.

3. **§195.404 - Pump station discharge pressure records.**

   • Discharge Pressure records in SCADA or at field locations?
   • Data Reduction & Archiving
   • Data acquisition frequency

Comments: Enbridge Energy has begun a program to replace pen & ink pressure recorders with digital pressure recorders. Currently, 40 out of approximately 100 recorders have been replaced. These are six channel digital recorders which look at pressure every second, records the pressure every minute and records the highest and the lowest pressure within that one minute span, however, the exact time of each high/low is not kept. If an event causes a cascade shut-down, then the records capture all pressures between 5 minutes before and 5 minutes after the shut-down. The pressure data is stored on zip disks and one year's worth of data can be stored on one zip disk. The data is also sent and recorded at Enbridge Energy's headquarters server as a backup.

4. §195.404 Maps and records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:
(1) Location and identification of the following pipeline facilities:
(I) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c) (9) applies;
(vii) Safety devices to which §195.428 applies.
(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations
- Ensure pipeline safety parameters are current (i.e., MOP, alarm set points, etc.)
- Review any emergency or abnormal operating condition or schedule deviation records generated by the SCADA system (alarm logs, trending data, etc.). Compare abnormal operating conditions noted in the SCADA data with the operator's report and reporting procedures as related to those abnormal operating conditions.
- Data Reduction & Archiving
- Data acquisition frequency

Comments: Enbridge Energy's actual SCADA system is located in Edmonton, Alberta, Canada and thus an actual on-site inspection of the SCADA system was not completed.

5. §195.408 - Communications.

(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system
(b)(1) Monitoring operational data as required by §195.402(c)(9)
- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-short Reports
- Maintaining pressures within limits described in **§195.406 Maximum Operating Pressure**

Attachment 1
SCADA Liquid Worksheet

Comments: Continuous data transmission with field locations. The operator has redundant communication paths. Critical alarms are classified and color coded on the display. Trending data is used that will trigger alarms if allowable values are exceeded. Over/short reports are done every 2 hours. Event logs can be generated.

6. **§195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance**
   - Over-Short Reports
   - Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments: Leak detection systems are provided for Lines, 1,2,3,5 and 13. A leak detection system for Line 4 is almost ready, the system is installed but the alarms are not active because they are fine tuning the settings. ~~A leak detection system for Line 6 has been~~ budgeted. Leak detection is not provided for Lines 14 and 17 (probably will be done next year). The system used is a Stoner Leak Detection System which uses real time transient hydraulic modeling of the pipelines. The system compares the model with what is actually occurring on the pipelines. The sensitivity ranges vary for each line, but an example would be Line 3 where the sensitivity is 28% of total flow over 5 minutes, 11% over 20 minutes and 6% over 2 hours. The leak detection system is part of the "10 minute" rule, which means that if the reason for a leak detection indication cannot be resolved within 10 minutes, then the line will be shut-down.

7. §195.420 & .428 - Testing of applicable SCADA controlled valves, safety devices, and overfill systems functionality.
   - Frequency of testing
   - Inclusion of SCADA component in the tests

Comments: Most SCADA valves are being used daily and this operation can be checked daily. Alarms are activated if there is a component failure. MOV valves are tested twice per year and are witnessed by field personnel. Other components (such as tank Hi-Hi alarms) are tested back to the SCADA system. There are monthly SCADA checks on the tank level alarms.

Attachment 2
Internal Corrosion Worksheet - Liquid Pipelines

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: x N: _____

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: x N: _____

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: x N: _____

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y: x N :_____

5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: x N: _____

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y: _____ N: x

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y: x N:_____

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion? Y: x N: _____

9. Does the operator track internal corrosion and take corrective action to prevent recurrence? Y: x N: _____

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
    _____ Gas and Fluid analysis
    _____ Rates of pipeline corrosion as determined by coupons
    x Solids removed from the system
    x Analysis of inhibitor samples from the pipeline
    x Magnetic and electronic device (pigs)
    x Other **Hydrogen Foils (Beta Foils)**

11. Is the inhibitor compatible with the product being transported? Y: x N: _____ N/A: _____

Comments: Jay Johnson, Compliance Coordinator, told us Enbridge recently started using inhibitor in Lakehead Tonawanda and they plan to install Beta-Foils in the near future to monitor internal corrosion.

Attachment 3
Operator Qualification Worksheet

The following questions are to be used by the inspector to provide information in determining a need for a more intensive OQ field inspection.

1. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual's performance of a covered task may have contributed to an accident?

Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):* **Interviewed George Barth, Operations Supervisor at Tonawanda for his response to this OQ issue. Mr. Barth's response was satisfactory and in accordance with the operator's OQ plan procedures.**

2. Do the supervisors know what actions to take, as required by the operator's OQ program, when an individual is identified that may no longer be qualified to perform a covered task?

Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):* **Interviewed George Barth, Operations Supervisor at Tonawanda for his response to this OQ issue. Mr. Barth's response was satisfactory and in accordance with the operator's OQ plan procedures.**

3. Do the individuals performing covered tasks know how to recognize and react to AOC's that may be encountered while performing tasks?

Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):* **Yes. They are incorporated in the OQ training and included in local safety meetings for which we show documentation.**

4. Are the employee and/or contractor individuals observed performing covered tasks qualified per OQ program requirements? (Documentation may be a hard copy or database records available at the job site or local office).

Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):* **Contractor, ISN, Project Coordinator (Mgr) on site with every project-yes observations made. Reviewed OP/Qual. database and observed hard copy records in field.**

5. Are the individuals who are observed performing covered tasks adhering to operator's procedures?

Comments: *(If Unsatisfactory please indicate why, either in this box or in a referenced note):* **Yes, the Project Manager and/or Supervisor have that responsibility.**

PIM Entry Examples

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	NoFail Pipeline Company	**OPID #:**	2314
Name of Unit(s):	Boardwalk and Parkplace	**Unit # (s):**	234, 278
Records Location:	Pipelineville, NC		
Unit Type & Commodity:	Interstate Hazardous Liquid (A1) - HVL		
Inspection Type:	Standard	**Inspection Date(s):**	12/24-27/03
OPS Representative(s):	John Brown	**AFO Days:**	4

Summary:

On December 24-27, I performed a standard inspection of the NoFail pipeline facilities contained in units 234 and 278. The evaluation report contains a component description of the two units. The inspection included a records and facilities review. A Joint O&M inspection was conducted in 2003 and no procedures were evaluated during this inspection. Pre-inspection preparation identified previous valve inspection violations: I reviewed all of the company's valve inspection records and five aboveground valve settings and did not identify any potential non-compliances. Right-of-way inspection and periodic cathodic protection checks were conducted between Chance, NC to Community Chest, NC and from Reading, SC to Ventnor, SC. The Mighty Big'n Wet River crossing was evaluated for atmospheric corrosion.

Findings:

The pipeline facilities appeared to be well maintained and serious concerns were noted: surface rusting was observed at the Pipelineville pump station. No pitting was observed. NoFail is in the process of repainting all of the aboveground piping at this facility.

The following concerns were noted from the records review:

1. The rectifiers in Unit 234 were inspected on 3 times in 2001, twice in 2002, and five times in 2003. Copies of the subject records were obtained.
2. The right-of-way in Unit 234 was densely overgrown such that aerial patrols would be ineffective. Pictures were taken of representative areas.

Field Notes

1. By-pass piping and valves associated with the Tonawanda Pump Station, built in 1997, were designed and constructed to accommodate the passage of instrumented internal inspection devices.

2. The pump station building is adequately ventilated and equipped with hazardous vapor warning devices. The facility is fenced and is greater than 50 feet from the boundaries of the station. The station was also equipped with numerous dry chemical fire extinguishers.

3. The pumps are equipped with over pressuring safety devices that are constantly monitored, a high-level sump tank alarm, and there are emergency shut down switches.

[redacted]

4. There is no pre-tested pipe stored at this unit.

5. We observed no Emergency Response Training because none was scheduled during our audit.

6. We observed right-of-way line markers at the following locations:
-Chippewa Channel of the Niagara River
-Tonawanda Channel of the Niagara River
-Tonawanda Pump Station
-Millersport Highway
-Williamsville Pump Station (Decommissioned)
-Park Club Lane, Williamsville
-Clinton Street, Buffalo
-Pierce Street, Buffalo
-Buffalo River
-Mineral Springs Road, West Seneca

The pipeline was adequately marked ant the signs displayed the required "compliant" wording on a sharply contrasting background.

7. We observed no right-of-way nor navigable water crossing inspections.

8. We observed cathodic protection readings at the following locations: Employees follow procedures and readings indicating cathodic protection was compliant.

Test Stations

Location	P/S Reading (volts)	Casing (Volts)
Park Club Lane	-1.823	-0.488
Clinton Street	-1.063	
Mineral Springs Road	-1.266	
Williamsville Station	-2.370	

Rectifiers

Location	Settings (volts/amps)	Design Limits (volts/amps)
Williamsville Station	35.06	60/20
Clinton Street	63/15	80/22
Pierce Street	76.5/11	80/28

Bonds

Location	Reading	Shunt
Mineral Springs Road	7.5 millivolts 7.5 amps	50/50

[redacted]

9. We observed exposed pipe at the Tonawanda Pump Station and we found no instances of atmospheric corrosion.

10. We observed no valve maintenance. A/C not scheduled.

11. We field-inspected valves to verify the valves from unauthorized operating and vandalism at the following locations. All the valves we observed were fenced, chained, locked and compliant:

-Chippewa Channel Launcher Facility
-Tonawanda Channel Receiver Facility
-Tonawanda Pump Station
-Williamsville Station
-Clinton Street
-Pierce Street (Buffalo River)
-Mineral Springs Road Receiver Facility

12. We observed L&R at the following locations that were equipped with pressure gauges and pressure relief piping and valves.

-Chippewa Channel Launcher Facility
-Tonawanda Channel Receiver Facility
-Mineral Springs Road Receiver Facility

13. We observed no pressure limiting device, relief valve, or pressure controller testing during our review. A/C none was scheduled.

14. We observed a 150 lb. and three 35 lb. dry chemical (purple K) fire extinguishers in and near the pump station. They were plainly marked and accessible. We noted their tags documented that they were inspected on a monthly and yearly schedule. The last inspection was completed on 6/3/04.

15. The unit has no break out tanks.

16. We observed signs around the pump station visible to the public, that displayed the name and telephone number of the operator.

17. The Tonawanda Pump Station facility is fenced in.

18. We observed no smoking signs posted at the Tonawanda Pump Station. Smoking was prohibited anywhere inside the facility.

19. We observed no Operator Qualification activities during our review. A/C none scheduled.

20. Enbridge's Lakehead Tonawanda (LT) line has been used to transport crude oil since it was constructed.

21. We obtained and reviewed Enbridge's 2003 report.

22. There were no accidents or safety related conditions reported on Line 10 in the past several years. We did, however, evaluate Enbridge's Maintenance Management system. Specifically we looked at the records for a call-out to the Tonawanda Pump Station, on May 14, 2003. Enbridge's Scada system detected a problem with pump unit #1 and it shut the pump down. Local personnel determined there was a bad outer bearing on the pump and they made the necessary repairs.

23. Line 10 has no offshore or abandoned underwater facilities.

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24. Enbridge has not had any construction activity on the Lakehead Tonawanda (LT) since they built the Tonawanda Pump Station. However, we looked at their ongoing operations and maintenance programs to verify the way they maintain Operator Qualification records for LT employees, other company employees, and contract workers.

Records for the LT employees were available locally via a company computer database. We evaluated records for LT employees and found no areas of concern.

Jay Johnson, Enbridge Compliance Coordinator, showed us the Company's Operator Qualification database for company employees including company welders and contract welders. He also showed us the Operator Qualification contract worker database on the internet at ISNetworld.com. We found no areas of concern.

Enbridge project engineers are responsible to ensure that people are qualified to perform construction and maintenance tasks they will perform on the company's pipelines. They have access to the Company's Operator Qualification database and the contractor's Operator Qualification database on the internet as well as access to hard copies of the records. They review individuals' qualifications and print them out prior to the start of construction and maintenance activities.

The Company was in the process of replacing clockspring clamps with welded full encirclement clamps at the time of our visit and we checked the Operator Qualifications of the employees the Company sent to LT to do the work. On June 23, 2004 we met with Steve Sleever, Project Manager, and we documented the following:

Name	Task	Qualification Data
Brad Grott	Welder	Qualified 10/02 – Witnessed by Steve Sleever
Lonnie Laubsher	Welder	Qualified 9/02 – Witnessed by Steve Sleever
Terry Rapp Jan X Co.	NDT	Level 3 – Qualifications expire on 5/06
	CWI	Qualified to Section 6.1 on 6/03
		Covered by Jan X Anti-Drug and Alcohol Misuse Prevention Programs

[redacted]

We found the Welding Procedure Specifications being used for the repairs on site in O&M Book 4.

- UF49US – Fillet Weld
- LB32 – Long Weld

We found NDT Procedures on site.

- Visual
- Mag Particle
- UT

The Company evaluated anomalies on site using R Streng to determine the need to repair vs. no repair. We did not find any areas of concern during this evaluation.

25. We did not review any test results to Qualify Welding Procedures during our evaluation of this unit.

26. We reviewed original construction reports documenting the design and location of various anode beds on LT.

27. We did not review any construction records.

28. We reviewed original pressure test records for the pipeline and did not find any areas of concern.

29. We did not review any records of Manufacturer's Testing of components.

30. We found no pre-tested pipe at LT.

31. We found documentation that the Company's O&M was reviewed annually.

Book#	**Review Interval**
1	2/25/03-3/16/04
3	6/17/02-9/17/03

32. All pipeline at LT is located in high consequence area.

33. We did not review any Abandonment of Facilities records.

34. LT participants in Pipeline Group Presentations. They send invitations to fire, police, and other public officials inviting them.

35. Enbridge has an on-going training and review program. We reviewed LT's records and found no

[redacted]

areas of concern.

36. Phil Archoletta reviewed these items.

37. These items are found in the Control Centers procedures and in local procedures Book 7. Also, everyone in the field has a personal procedures manual with them Subject # 02-02-01.

38. Post Accident Reviews are conducted locally and regionally under Subject 02-02-10. All require the 7000-1 closure form.

39. LT conducts yearly drills to maintain their Emergency Response skills and knowledge. We reviewed drill records from 5/30/02 and 6/28/03 and we found no areas of concern.

40. LT maintains current maps and records of their pipeline. We evaluated their maps and records and we found no areas of concern.

41. LT has one pipeline in the unit with the same diameter and wall thickness throughout the system. We reviewed copies of original pressure test records and we found no areas of concern.

42. LT maintains pump discharge pressure records for longer than 3 years.

43. LT records are maintained on a Facman Database. We reviewed records for a call-out to the Tonawanda Pump Station. The Company's Scada system detected a problem with pump unit #1 and it shut the pump down. Local personnel determined there was a bad outer bearing on the pump and they made the necessary repairs. We found their records retention program to be compliant.

44. Jay Johnson, Compliance Coordinator, had several binders containing the documentation for all repairs made to LT. All reports documented inspections for internal and external corrosion. We reviewed a repair at MP1935 made on 6/25/03 and we found no areas of concern.

45. We reviewed records from 2003 on and we found no areas of concern.

46. We reviewed records for the following ROW inspections and we found no areas of concern:

2/16/04	5/0504
3/04/04	5/26/04
4/20/04	6/09/04
4/26/04	

47. We reviewed the findings of the 2003 inspection of the Niagara and Buffalo River and we found no areas of concern.

48. N/A

49. We reviewed inspection records for all LT valves dated 12/04/03 and 4/21/04 and we found no areas of concern.

[redacted]

50. We reviewed LT's records for over pressure safety devices for 2003 and 2004 and we found they were complaint.

51. LT has no HVL tanks.

52. LT has no tanks.

53. LT is a member of the Dig Safely New York One-Call System. We reviewed field markings at Sweetbriar Road and Park Club Lane and found the markings were yellow and displayed the company, the size of the line, the kind of pipe and the pipeline commodity-crude oil. We looked at the mark-out database to verify that LT was calling back and we found no areas of concern.

Date	Ticket#	Call Back (Y/N)
5/28/04	05284-561-016-00	Y
6/01/04	06014-114-023-00	Y
6/0904	06094-561-001-00	Y

54. We obtained copies of the 2002-2003 LT corrosion inspection report for test station, bonds and rectifiers. All test stations met the -0.850 millvolt criteria. We noted that rectifiers at Clinton and Pierce Streets were operating at voltages higher than their design limits. We visited these rectifiers in the field and found there were replaced with rectifiers that had a higher rating. We recommend that LT make the necessary corrections on their report. All bonds and rectifiers were read monthly. We found no areas of concern.

55. LT has no unprotected lines.

56. Jay Johnson, Compliance Coordinator, told us that LT has just started using a corrosion inhibitor and they will be installing Beta-Foils to monitor internal corrosion.

57. We observed no atmospheric corrosion at the Tonawanda Pump Station. Jay Johnson gave us a copy of an Operations Manual Revision request that provides for atmospheric corrosion surveys every 3 years and not to exceed 39 months. We also obtained a copy of Enbridge's Atmospheric Corrosion Coating Assessment form. We found no areas of concern.

58. We reviewed site specific maps for rectifiers and anode beds and we found no areas of concern.

59. The facility response plan is documented in O&M Manual Book #8.

60. We reviewed the names and telephone number in the FRP and found they were current.

61. Enbridge is the primary responder.

62. We reviewed LT's oil spill exercise program for 5/19/03 and 5/26/04 and we found no areas of concern.

63. LT participates in the local one-call system and they advertise in several local medias. The program is on-going and compliant. They plan a public awareness mailing later this year which will focus on

[redacted]

educating key stakeholders as opposed to just Landowners and Contractors. That mailing will reach "Affected Stakeholders," which includes all right-of-way landowners, plus ROW tenants and nearby businesses, residents and places of congregation out to a minimum of 660 feet from the centerline. In accordance with API RP1162, the Affected Public will receive information about the pipeline at least once every two years. In addition, we will be mailing information to area excavators, first responders and local elected officials. They intend to continue their efforts to personally contact first responders but believe the mailings will help reinforce their emergency response safety messages. Certain circumstances -- such as high consequence areas -- may result in supplement communications, which could include annual vs. biannual mailings -- or other public awareness activities.

Inspection Summary

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

Central Region Office

Office of Pipeline Safety

To: Region Director JH

Date: 10/3/03

From: Phil Archuletta, Staff Engineer P.A.

Company Inspected: ENBRIDGE ENERGY, LP

Operator: ENBRIDGE ENERGY, LP

Type of Service: Interstate Liquid

Units:	Unit I.D.	Inspection I.D.
Escanaba	Unit #1353	103408

Dates of Inspection: 8/13/03 - 8/14/03 (field); 9/8/03 - 9/10/03 (records); 9/16 – 9/18 (field)

Location: Superior, WI (records); States of Michigan and Wisconsin (field facilities)

Facilities Inspected: Phil Archuletta from CE OPS conducted a standard unit inspection of Enbridge Energy's Escanaba unit. The inspection was conducted using the "Standard Inspection Report of a Liquid Pipeline Carrier" inspection form. Enbridge Energy's records were reviewed at the Enbridge Energy office in Superior, WI. All documents and records requested were presented and were satisfactory with the exception of items noted below under "Deficiencies Found."

Enbridge Energy's facilities for this unit consist of the following:

- 30" line from the Ino, WI Pump Station to the Lewiston, MI Pump Station
- 10 Pump stations located at Ino, Saxson (all in WI) and Gogebic, Iron River, Rapid River, Manistique, Gould City, Naubinway, Mackinaw and Indian River (all in MI).

The actual physical facilities inspected included all of the facilities listed in the preceding paragraph.

A number of stops were made at valve settings, the single pump station and points along the pipeline segments where C/P readings could be taken.

Persons Interviewed:

Refer to the "Attendance Sheet" included with the attached "Standard Inspection Report of a Liquid Pipeline Carrier" form for a listing of persons interviewed.

Deficiencies Found:

Enbridge Energy's O&M Manuals were not evaluated. This operator had a Team O&M inspection in June, 2002.

A review of Enbridge Energy's records and field facilities identified the following deficiencies:

Records Issues:

No records deficiencies were noted.

Field Issues:

A. Letter of Concern items:

1. At MP 1149.44, the right-of-way is overgrown with weeds, small bushes, plants and small trees.

2. At MP 1226.20, the Gogebic Pump Station, the paint coating on the station piping is deteriorated.

3. At MP 1235.55, the right-of-way is overgrown with weeds, small bushes, plants and small trees.

Conclusions/Recommendations:

It is recommended that Enbridge Energy be issued a Letter of Concern for all items listed under paragraph A above.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: ENBRIDGE ENERGY, LP

H.Q. Address:	**System/Unit Name and Address:**
SUITE 3300 1100 LOUISIANA HOUSTON, TX 77002-5217	Escanaba 2811 27th Ave N Escanaba, WI 49829-9829
Co. Official: Mr. Dan Tutcher, President	**Phone No.:**
Phone No.: 713-650-8900	**Fax No.:**
Fax No.: 713-653-6711	**Emergency Phone No.:** 800-858-5253
Emergency Phone No.: 800-858-5253	**Unit Record ID#:** 1353
Operator ID#: #11169	**Activity Record ID#:** 103408

Persons Interviewed	Titles	Phone No.
Refer to attached copy of		
attendance sheet.		

OPS Representative(s): Phil Archuletta

Date(s): 8/13-8/14 (field); 9/8-9/10 (records); 9/16-9/18 (field);

Company System Maps (copies for Region Files): YES, placed in the operator file.

Unit Description:

30" LINE #5 FROM MP 1137.32 (INO PUMP STA.) TO 1548.60 (LEWISTON PUMP STA.).

Portion of Unit Inspected:

FROM MP 1137.32 (INO PUMP STA.) TO 1548.60 (LEWISTON PUMP STA.)

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections.

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description RECORDS REVIEW
Date 9/8 - 9/10 **Location** Enbridge Energy - Superior, WI Office

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	Staff Engineer	DOT Office of Pipeline Safety	(816) 329-3807	phillip.archuletta@rspa.dot.gov
2	GAIL FOLLIS	RECORDS MANAGEMENT	ENBRIDGE	(715) 394-1536	GAIL.FOLLIS@ENBRIDGE.COM
3	JAY JOHNSON	COMP COORD	"	715/394-1512	jay.johnson@enbridge.com
4	RANDY WILBERG	SAFETY - TRAINING COMPLIANCE	ENBRIDGE	715-394-1412	RANDY.WILBERG@ENBRIDGE.COM
5	AL ALEKNAVICIUS	MANAGER PIPELINE SERVICES	ENBRIDGE	715 3941415	AL.ALEKNAVICIUS@ENBRIDGE.COM
6	Floyd Mott	Project Specialist	Enbridge	715-394-1586	Floyd.Mott@Enbridge.com
7	Todd Gilseth	Safety, Training Compliance	Enbridge	218-759-6615	Todd.Gilseth@Enbridge-us.com
8	Brian Pierzina	Sr. Engineer	MNOPS	218-327-4218	brian.pierzina@state.mn.us
9	Adam Erickson	Project Manager	Enbridge	715 394-1548	adam.erickson@enbridge.com
10	Patsy Bolk	Compliance Sec.	Enbridge	715 394-1504	patsy.bolk@enbridge.com
11	WILLIAM C. CHELLEW	CORROSION TECHNICIAN	ENBRIDGE	715-394-1413	bill.chellew@enbridge.com
12	John W. Bissell	CORROSION TECHNICIAN	ENBRIDGE	715-394-1417	john.bissell@enbridge.com
13	Mark JERABEK	COMMUNICATIONS COORD.	ENBRIDGE	715-394-1538	mark.JERABEK@ENBRIDGE.com
14	Daniel Klavner	Regional Engineer	Enbridge	715-394-1414	dan.klavner@enbridge.com
15	Dana Slade	Sr. Env. Analyst	Enbridge	(715) 394-1578	dana.slade@enbridge.com
16	NANCY R. BRYCE	H. FIELD SERVICES SUPERVISOR	ENBRIDGE	715-394-1558	nancy.bryce@enbridge.com
17	LYNNE HARRINGTON	TRAINING COORD.	ENBRIDGE	(715) 394-1642	LYNNE.HARRINGTON@ENBRIDGE.COM

8.	GREG SCHELIN	TECHNICAL SUPERVISOR	ENBRIDGE	(715) 398-8363	greg.schelin@enbridge.com
9.	DENNIS WEDAN	ASS'T. TERMINAL SUPERVISOR	ENBRIDGE	(715) 398-8323	dennis.wedan@enbridge.com
10.	RICK AUNET	TERMINAL SUPERVISOR	ENBRIDGE	(715) 398-8322	RICK.AUNET@ENBRIDGE.COM

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

HVL PIPELINE TESTING SUMMARY	N/A	Yes	No
1. Do the operator's pipelines transport HVLs?		✔	
2. Has the operator pressure tested the following "older" HVL pipelines per subpart E; or, for pipelines that have not been converted under 195.5, has the operator established these pipelines' MOP's per 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure]? **The pressure test and MOP establishment (195.406(a)(5)) deadlines for the below listed lines have passed.**		✔	
a. Onshore non low stress Interstate Lines in HVL service prior to 9/8/80 and constructed prior to 1/8/71.		✔	
b. Onshore non low stress Intrastate Lines in HVL service prior to 4/23/85 and constructed prior to 10/21/85.	✔		
c. Low stress lines in HVL service that existed on 7/12/94, or ones that were constructed before 8/11/94.	✔		

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

PIPELINE INFORMATION

Boundaries of Unit:

FROM MP 1137.32 (INO PUMP STA.) TO MP 1548.60 (LEWISTON PUMP STA.).

Pipelines and Pumping Stations in Unit:

30" LINE #5 FROM MP 1137.32 (INO PUMP STA.) TO 1548.60 (LEWISTON PUMP STA.).

Gogebic, Iron River, Rapid River, Manistique, Gould City, Naubinway, Mackinaw, Indian River (all in Michigan)

Ino, Saxon (all in Wisconsin)

Miles of Pipeline:	Protected				Unprotected			
Steel Bare								
Steel Coated	411.3							
Other								

Breakout Tank Facilities:

N/A

Offshore Facilities:

N/A

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Conversion to Service		S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?			✔	

Comments *(If the above is Unsatisfactory, please indicate why):*

Subpart B - Reporting Procedures			S	U	N/A	N/C
.402 (c)(2)		Does the operator have procedures for gathering data needed for reporting accidents under **Subpart B** of this part in a timely and effective manner?				✔
	.50	Does the operator file accident reports as required under 195.50? Under certain conditions, a release of more than 5 gals, or more is reported.				✔
	.52	Are certain incidents telephonically reported to the **National Response Center**?				✔
	.54	Are the incidents reported by telephone followed up with a 30-day written report?				✔
.402(f)		Does the operator have procedures for recognizing and discovery of safety-related conditions?				✔
	.55	If the operator reported a safety-related condition, did they use the proper criteria?				✔
	.56	Is there a procedure for reporting safety-related conditions?				✔
	.56(a)	Was the report filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery?				✔
	.56(b)	Was proper corrective action taken?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Subpart C - Passage of Internal Inspection Device Procedures			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Has each new pipeline or each section of a pipeline which pipe or components has been replaced been designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory   U - Unsatisfactory   N/A - Not Applicable   N/C - Not Checked

		Subpart D - Welding Procedures	S	U	N/A	N/C
		Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422, as well as §195.200.				
.402(c)/ .422	.214(a)	Is the welding performed in accordance with welding procedures qualified to produce welds meeting the requirements of this **Subpart**?				✔
		Has the quality of the test welds to qualify the procedures been determined by destructive testing?				✔
	.214(b)	Is each welding procedure recorded in detail?				✔
		Are welding procedures qualified in accordance with a standard that is accepted by the industry? **(API 1104, ASME Boiler & Pressure Code - Section IX, or other)**				✔
	.222	Is welding performed by welders, who have been qualified in accordance with **Section 3 of the API Standard 1104 (18th Ed., 1994)** or **Section IX of the ASME Boiler and Pressure Vessel Code (1995)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition?				✔
Alert Notice 3/13/88		**In the welding of repair sleeves and fittings, does the operator's procedures give consideration to:**				
		1. The use of low hydrogen welding rods.				
		2. Cooling rate of the weld.				
		3. Metallurgy of the materials being welded (weldability carbon equivalent).				
		4. Proper support of the pipe in the ditch.				
.402(c)/ .422	.226(a)	Does the operator require the repair (within pipe and (b) specification thickness tolerances) or replacement of arc burns?				✔
	.226(b)	Does the operator require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**				✔
	.226(c)	When pipe is being welded, is the ground wire attached to the pipe by other means than welding?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Welds: Acceptability - Nondestructive Testing Procedures	S	U	N/A	N/C
.402(c)/ .422	.228	Does the operator nondestructively test welds to insure their acceptability according to **Section 6 of API 1104 (18th)** and per the requirements of **§195.234** in regard to the number of welds to be tested?				✔
	.234(b)	Is nondestructive testing of welds performed:				
		1. In accordance with written procedures for **NDT**.				✔
		2. By qualified personnel.				✔
		3. By a process that will indicate any defects that may affect the integrity of the weld.				✔
	.266	Does the operator maintain records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Welds: Repair or Removal of Defect Procedures	S	U	N/A	N/C
.402(c)/ .422	.230	Does the operator remove and/or repair welds that are unacceptable in accordance with the requirements of **§195.230**?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Subpart E - Pressure Testing Procedures	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Does the operator pressure test each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced?				✔
		Are lines that have not been pressure tested per subpart E being operated in accordance with this subsection?				✔
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195. 303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				✔
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				✔
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines).			✔	
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).			✔	
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).			✔	
	.303	Does the operator comply with the risk based alternative to pressure testing?				✔
	.304	The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure.				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

		Subpart E - Pressure Testing Procedures (Con't)	S	U	N/A	N/C
.402(c)/ .422	.305(a)	Does the operator pressure test under **§195.302** all pipe, all attached fittings, including components?				✔
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				✔
	.306	Is the appropriate test medium used?				✔
	.308	Does the operator pressure test pipe associated with tie-ins as one segment or tested separately?				✔
	.310(a)	Does the operator maintain a record of each pressure test required by this **Subpart**?				✔
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				✔
	.310(b)(2)	Test instrument calibration data.				✔
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				✔
	.310(b)(4)	Date and time of the test.				✔
	.310(b)(5)	Minimum test pressure.				✔
	.310(b)(6)	Test medium.				✔
	.310(b)(7)	Description of the facility tested and the test apparatus.				✔
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				✔
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Subpart F - Operations & Maintenance Procedures	S	U	N/A	N/C
.402(a)	.402	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				✔
		b. Does the operator review the manual at intervals not exceeding 15 months, but at least each calendar year?				✔
		c. Are the manuals available, as required?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

		Maintenance & Normal Operation Procedures	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				✔
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				✔
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				✔
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				✔
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?				✔
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				✔
	.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				✔
		Reporting abandoned pipeline facilities under commercially navigable waterways per §195.59				
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				✔
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				✔
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				✔
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Abnormal Operation Procedures (Control Center Function)			**S**	**U**	**N/A**	**N/C**
.402(a)	**.402(d)**	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				✔
		ii. An increase or decrease or flow rate outside normal operating limits?				✔
		iii Loss of communications?				✔
		iv. The operation of any safety device?				✔
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				✔
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				✔
	.402(d)(3	Correcting variations from normal operation of pressure and flow equipment controls?				✔
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				✔
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Emergency Procedures			**S**	**U**	**N/A**	**N/C**
.402(a)	**.402(e)**	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				✔
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				✔
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				✔
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				✔
	.402(e)(	Controlling the release of liquid at the failure site?				✔
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				✔
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				✔
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				✔
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Emergency Response Training Procedures (Control Center & Field)			S	U	N/A	N/C
.402(a)	**.403(a)**	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the operating and maintenance, and emergency response procedures established under §195.402.				✔
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				✔
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				✔
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				✔
	.403(a)(5)	Learn the proper use of fire fighting procedures and equipment, fire suits, and breathing apparatus, etc.				✔
	.402(f)	Recognize and report safety related conditions.				✔
	.403(b)	At intervals not exceeding 15 months, but at least once each calender year:				
	.403(b)(1)	Does the operator review with personnel their performance in meeting the objectives of the emergency response training program?				✔
	.403(b)(2)	Does the operator make appropriate changes to the emergency response training program?				✔
	.403(c)	Does the operator require and verify, its supervisors maintain a thorough knowledge of the emergency response procedures they are responsible for?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

		Maps and Records Procedures	S	U	N/A	N/C
.402(a)	**.402(c)(1)**	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				✔
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				✔
		ii. Pump stations				✔
		iii. Scraper and sphere facilities				✔
		iv. Pipeline valves				✔
		v. Facilities to which **§195.402(c)(9)** applies				✔
		vi. Rights-of-way				✔
		vii. Safety devices to which **§195.428** applies				✔
	.404(a)(2	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				✔
	.404(a)(3	The maximum operating pressure of each pipeline.				✔
	.404(a)(4	The diameter, grade, type, and nominal wall thickness of all pipe.				✔
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				✔
	.404(b)(	Any emergency or abnormal operation to which the procedures under **§195.402** apply.				✔
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				✔
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				✔
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Maximum Operating Pressure Procedures (MOP) - All Systems	S	U	N/A	N/C
.402(a)	.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1	The internal design pressure of the pipe determined by **§195.106**.				✔
	.406(a)(2	The design pressure of any other component on the pipeline.				✔
	.406(a)(3	**80%** of the test pressure **(Subpart E)**.				✔
	.406(a)(4	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				✔
	.406(a)(5)	**80%** of the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				✔
	.406(b)	The pipeline may not be operated at a pressure that exceed **110% of the MOP**:				
		a. Are adequate controls and protective equipment installed to prevent the pressure from exceeding **110%** of the **MOP**?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Communication Procedures (Control Center)	S	U	N/A	N/C
.402(a)	.408(a)	Does the operator have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system?				✔
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(	Monitoring operational data as required by **§195.402(c)(9)**.				✔
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				✔
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				✔
	.408(b)(4)	Providing commuñication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Line Marker Procedures	S	U	N/A	N/C
.402(a)	.410(a)	Each operator shall place and maintain line markers over each buried pipeline in accordance with the following:				
	.410(a)(1)	Are line markers placed at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known?				✔
	.410(a)(2	Do the line markers have the correct characteristics and information?				✔
	.410(c)	Are line markers placed where pipelines are aboveground in areas that are accessible to the public?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Inspection of Rights-of-Way & Crossings Under Navigable Water Procedures	S	U	N/A	N/C
.402(a)	.412(a)	Does the operator inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**?				✔
		Does the operator follow-up on problems noted by the patrol?				
	.412(b)	Does the operator inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

		Underwater Inspection Procedures of Offshore Pipelines	**S**	**U**	**N/A**	**N/C**
.402(a)	**.413(b)**	When the operator discovers a pipeline, it operates, is exposed on the seabed or constitutes a hazard to navigation does the operator:				
	.413(b)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center.			✔	
	.413(b)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation			✔	
	.57	Has the operator **filed** a report within **60 days** of the inspection as required by **§195.413**?			✔	

Comments *(If any of the above is Unsatisfactory, please indicate why):*

		Valve Maintenance Procedures	**S**	**U**	**N/A**	**N/C**
.402(a)	**.420(a)**	Does the operator maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times?				✔
	.420(b)	Does the operator inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year?				✔
	.420(c)	Does the operator provide protection for each valve from unauthorized operation and from vandalism?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Pipeline Repair Procedures	S	U	N/A	N/C
.402(a)	.422(a)	Does the operator, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property?				✔
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Pipe Movement Procedures	S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, does the operator reduce the pressure for the line segment involved to **50% of the MOP**.				✔
	.424(b)	For **HVL** lines **joined** by welding, does the operator:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				✔
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.				✔
	.424(b)(3)	Reduce the pressure for the line segment involved to **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				✔
	.424(c)	For **HVL** lines **not joined** by welding, does the operator:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				✔
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.				✔
	.424(c)(3	Isolate the line to prevent flow of the **HVL**.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Scraper and Sphere Facility Procedures	S	U	N/A	N/C
.402(a)	.426	Does the operator, have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres?				✔
		Does the operator have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Overpressure Safety Device Procedures	S	U	N/A	N/C
.402(a)	.428(a)	Does the operator inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable?				✔
		Does the operator inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				✔
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.				✔
	.428(b)	Does the operator inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**?				✔
	.428(c)	Do aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to the appropriate API. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual ('195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				✔
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Firefighting Equipment Procedures	S	U	N/A	N/C
.402(a)	**.430**	Does the operator maintain adequate firefighting equipment at each pump station and breakout tank areas?				✔
	.430	The equipment must be:				
		a.. In proper operating condition at all times.				✔
		b. Plainly marked so that its identity as firefighting equipment is clear.				✔
		c. Located so that it is easily accessible during a fire.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Breakout Tank Procedures	S	U	N/A	N/C
.402(a)	**.432(a)**	Inspection of in-service breakout tanks. (annually/ 15mo) includes anhydrous ammonia and any other breakout tank that is not inspected per 432 (b) & (c);				✔
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).				✔
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.				✔
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.				✔
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

		Sign Procedures	S	U	N/A	N/C
.402(a)	.434	Does the operator maintain signs visible to the public around each pumping station and breakout tank area?				✔
		Do the signs contain the name of the operator and an emergency telephone number?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Security of Facility Procedures	S	U	N/A	N/C
.402(a)	.436	Does the operator provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Smoking or Open Flame Procedures	S	U	N/A	N/C
.402(a)	.438	Does the operator prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors?				✔

Comments *(Ifany of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Public Education Procedures	S	U	N/A	N/C
.402(a)	.440	Has the operator established a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				✔
		Is the program conducted in English and other languages where appropriate?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Damage Prevention Program Procedures	S	U	N/A	N/C
.402(a)	.442(a)	Does the operator have a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				✔
	.442(b)	Does the operator participate in a qualified One-Call program?				✔
	.442(c)(1)	Include the identity, on current a basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				✔
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				✔
		ii. How to learn the location of underground pipelines before excavation activities are begun.				✔
	.442(c)(3	Provide a means of receiving and recording notification of planned excavation activities.				✔
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				✔
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				✔
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequency as necessary during and after the activities to verify the integrity of the pipeline.				✔
		ii. In the case of blasting, any inspection must include leakage surveys.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		CPM/Leak Detection Procedures	S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

High Consequence Areas & Pipeline IMP Procedures		S	U	N/A	N/C
§195.450 & §195.452	These sections are being addressed by the OPS IMP group.				

Subpart G - Operator Qualification Procedures		S	U	N/A	N/C
§195.501-509	Refer to Operator Qualification Protocols				✔

Subpart H - Corrosion Control Procedures			S	U	N/A	N/C
.402(a)	.555	Does the Operator require and verify that supervisors maintain a through knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.				✔
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				✔
		a) constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under 195.424				✔
		b) Converted under 195.5 and 1) Has an external coating that substantially meets 195.559 before the pipeline is placed in service or:				✔
		2) Is a segment that is relocated, replaced, or substantially altered.				✔
	.559	**Coating Materials;** Coating material for external corrosion control must; a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				✔
	.561	a. All external pipe coatings required under 195.557 must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				✔
		b. All coating damage discovered must be repaired.				✔
	.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in 195.557(a) within one (1) year?				✔
		b. Each buried or submerged pipeline converted under 195.5 must have cathodic protection if the pipeline-				✔
		1. Has cathodic protection that substantially meets 195.571 before the pipeline is placed in service, or				✔
		2. Is a segment that is relocated, replaced, or substantially altered.				✔
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Subpart H - Corrosion Control Procedures (Con't)	S	U	N/A	N/C
.402(a)		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				✔
		e. Unprotected pipe must have cathodic protection if required by 195.573(b).				✔
	.567	Test leads installation and maintenance				✔
	.569	Examination of Exposed Portions of Buried Pipelines				✔
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference)				✔
	.573	a. (1) Pipe to soil monitoring (annually / 15months)				✔
		Separately protected short sections of bare ineffectively coated pipelines (every 3 years not to exceed 39 months)				✔
		(2) Before 12/29/2003 or not more than 2 years after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE RP0169-96.				✔
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment.				✔
		2) Before 12/29/2003 - at least once every 5 years not to exceed 63 months.				✔
		Beginning 12/29/2003 - at least once every 3 years not to exceed 39 months.				✔
		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - at least 6 times each year, intervals not to exceed 2 ½ months.				✔
		e. Any deficiencies identified in corrosion control must be corrected as required by				✔
	.575	Are there adequate provisions for electrical isolations?				✔
	.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects?				
		b. Design & install CP systems to minimize effects on adjacent metallic structures.				✔
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken?				✔
		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion				✔
		Coupons or other monitoring equipment must be examined at least 2 times each year, not to exceed 7 ½ months.				✔
		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe? What steps are taken to minimize internal corrosion.				✔
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material. (See exception to this statement)				✔
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least once every 3 years but at intervals not exceeding 39 months.				✔
		OFFSHORE - At least once each year, but at intervals not exceeding 15 months.				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Subpart H - Corrosion Control Procedures (Con't)	**S**	**U**	**N/A**	**N/C**
.402(a)	**.585**	1. Are Procedures in place and are they followed to either reduce the MOP, or repair/replace pipe if general corrosion has reduced the wall thickness?				✔
		2. Are Procedures in place and are they followed to either reduce the MOP, or repair/replace if localized corrosion has reduced the wall thickness?				✔
	.587	Are applicable methods used in determining the strength of corroded pipe (ASME B-31G, RSTRENG)				✔
	.589	Corrosion Control Records Retention(Some are required for 5 yrs; Some are for the service life)				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Best Practice:
Are the breakout tanks equipped with high level alarms?

Comments: Enbridge's breakout tanks have two stages of high level alarms set at "High" and at "High – High". The "High – High" alarm is independent of the "High" alarm. The "High" level is via a tape type floating gauging system. The tape gauging system also includes a gauge near the bottom of each tank which can be used for a visual indication of the tank's level.

Note:
How often are they checked?
Is the check all the way back to the SCADA center to ensure the hardware between the sensor and SCADA is good?

Best Practice:
Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

Comments: Enbridge has recently added mailings to planning and zoning directors as part of Enbridge's program. Presentations are for county officials such as county clerks and zoning personnel.

Best Practice:
Does the operator's damage prevention program include pro-active liaison with local school officials, where the pipeline traverses or is adjacent to, school property?

Comments: Enbridge does not have a pro-active company wide program for liaison with school officials. The district level offices have some contact with schools located along Enbridge's right-of-way. Enbridge's presentation to schools is focused on school staff members and school administrative personnel.

Best Practice:
Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

Comments: Enbridge is a member of the Common Ground Alliance. Enbridge has one member of the Common Ground committee. The Common Ground study was reviewed by approximately 6 Enbridge individuals.

Best Practice:
Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

Comments: Enbridge compared Enbridge's plan to the Common Ground practices and recommendations were forwarded to the District Managers.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Best Practice:

Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

Comments: Enbridge has modified their public awareness program based on some of the practices in the Common Ground study. Enbridge now sends two people out to audit One-Call centers. The modifications done to Enbridge's damage prevention program as a result of the Common Ground Study were minor in nature.

Best Practice:

Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

Comments: Enbridge incorporates the 4 or 5 points on digging/damage prevention in the study. Enbridge looks at damage prevention as a whole process that goes beyond just "call before digging". Enbridge feels that "call before digging" should include all steps (call in, wait the required time interval, pay close attention to the pipeline company=s markers, use safe procedures while digging, etc.) Enbridge has modified their internet website to provide better public awareness.

Best Practice:

Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities?

Comments:

Best Practice:

NPRM Qualification of Pipeline Personnel
Are trained/qualified personnel used for pipeline locating & marking?

Comments: Enbridge uses only trained company employees to locate and mark lines. Line locating and marking is one of the covered tasks in Enbridge's operator qualification plan. Enbridge has 3 crossing coordinators who have attended the one week course at Staking University in Marysville, MI. These crossing coordinators then conduct field training of other LPL personnel. Vendors go to Enbridge field locations and train personnel on the use of specific line locating equipment.

Note: Are contractors used? What does their training consist off? How is quality control ensured when using a third party?

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

Best Practice:

What factors are considered in determining the need for and timing of pigging and close interval surveys?

Comments: Enbridge uses such factors as coating type, product type, leak history, pipe type, operation history, internal inspection history, defect history and seam weld type. Enbridge uses an overlay of high resolution tool runs to determine corrosion rates to determine future intervals for tool runs. Close interval surveys are done every 5 years.

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.120	Have new pipelines, or pipeline sections of which pipe or components have been replaced, been designed and constructed to accommodate smart pigs ? (See exceptions under (b) and (c))	✔			
.262	Pumping Stations	✔			
.262	Station Safety Devices	✔			
.308	Pre-pressure Testing Pipe - Marking and Inventory	✔			
.403	Knowledge of Operating Personnel	✔			
.410	Right-of-Way Markers	✔			
.412	River Crossings	✔			
.557	Cathodic Protection (test station readings, other locations to ensure adequate CP) levels)	✔			
.573	Pipeline Components Exposed to the Atmosphere		✔		
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	✔			
.420	Valve Maintenance	✔			
.420	Valve Protection from Unauthorized Operation and Vandalism	✔			
.426	Scraper and Sphere Facilities and Launchers	✔			
.428	Pressure Limiting Devices	✔			
.428	Relief Valves - Location - Pressure Settings - Maintenance	✔			
.428	Pressure Controllers	✔			
.430	Fire Fighting Equipment	✔			
.432	Breakout Tanks			✔	
.434	Signs - Pumping Stations - Breakout Tanks	✔			
.436	Security - Pumping Stations - Breakout Tanks	✔			
.438	No Smoking Signs	✔			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	Conversion to Service				
.5(a)(1)	Testing to Verify MOP (ASME<Appendix N)			✔	
.5(a)(2)	Inspection of Pipeline Right-of-Way			✔	
.5(c)	Pipeline Records (Life of System)			✔	
	Pipeline Investigations			✔	
	Pipeline Testing			✔	
	Pipeline Repairs			✔	
	Pipeline Replacements			✔	
	Pipeline Alterations			✔	
	Reporting				
.52	Telephonic Reports to NRC (800-424-8802)	✔			
.54(a)	Written Accident Reports (DOT Form 7000-1)	✔			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	✔			
.56	Safety Related Conditions	✔			
.57	Offshore Pipeline Condition Reports			✔	
.59	Abandoned Underwater Facility Reports			✔	
	Construction				
.204	Construction Inspector Training/Qualification	✔			
.214(b)	Test Results to Qualify Welding Procedures	✔			
.222	Welder Qualification	✔			
.234(b)	Nondestructive Technician Qualification	✔			
.589	Cathodic Protection	✔			
.266	Construction Records	✔			
.266(a)	Total Number of Girth Welds	✔			
	Number of Welds Inspected by NDT	✔			
	Number of Welds Rejected	✔			
	Disposition of each Weld Rejected	✔			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	✔			
.266(c)	Location of each Crossing with another Pipeline	✔			
.266(d)	Location of each buried Utility Crossing	✔			
.266(e)	Location of Overhead Crossings	✔			
.266(f)	Location of each Valve and Test Station	✔			
	Pressure Testing				
.310	Pipeline Test Record	✔			
.305(b)	Manufacturer Testing of Components	✔			
.308	Records of Pre-tested Pipe			✔	

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory　　U - Unsatisfactory　　N/A - Not Applicable　　N/C - Not Checked

PART 195 - RECORDS REVIEW (con't)		S	U	N/A	N/C
	Operation & Maintenance				
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	✔			
.402(c)(10)	Abandonment of Facilities			✔	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Emergency Agencies	✔			
.402(c)(13)	Review of work Performed by Personnel	✔			
.402(d)(1)	Response to Abnormal Pipeline Operations	✔			
.402(d)(5)	Review of Personnel Response to Abnormal Operations	✔			
.402(e)(1)	Notices of Emergencies	✔			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	✔			
.402(e)(9)	Post Accident Reviews	✔			
.403(a)	Employee Training	✔			
.403(b)	Annual Review of Personnel Performance	✔			
.403(c)	Verification of Supervisor Knowledge	✔			
.404(a)(1)	Maps or Records of Pipeline System	✔			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	✔			
.404(a)(3)	MOP of each Pipeline	✔			
.404(a)(4)	Pipeline Specifications	✔			
.404(b)(1)	Pump Station Daily Discharge Pressure	✔			
.404(b)(2)	Abnormal Operations (§195.402)	✔			
.404(c)(1)	Pipe Repairs	✔			
.404(c)(2)	Repairs to Parts of the System other than Pipe	✔			
.406(a)	Establishing the MOP	✔			
.412(a)	Inspection of the ROW	✔			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	✔			
.413(b)	Inspection of Pipelines in Gulf of Mexico			✔	
.420(b)	Inspection of Mainline Valves	✔			
.428(a)	Inspection of Overpressure Safety Devices	✔			
.428(b)	Inspection of Relief Devices on HVL Tanks	✔			
.430	Inspection of Fire Fighting Equipment	✔			
.432	Inspection of Breakout Tanks			✔	
.440	Public Education	✔			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

	PART 195 - RECORDS REVIEW (Cont.)	S	U	N/A	N/C
	Damage Prevention Program				
.442(c)(1)	List of Current Excavators	✔			
.442(c)(2)	Notification of Public/Excavators	✔			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	✔			
	Corrosion Control				
.569	Inspection of Exposed Pipelines (External Corrosion)	✔			
.573(a)	External Corrosion Control - Protected Pipelines	✔			
.573(b)	External Corrosion Control - Unprotected Pipelines			✔	
.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	✔			
.579(a)	Corrosive effect investigation	✔			
.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment			✔	
.579(c)	Inspection of Removed Pipe for Internal Corrosion	✔			
.589	Cathodic Protection (Maps showing anode location, test stations, CP systems, etc)	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Oil Pollution Act High Impact Inspection (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number <u>865 District 3, 866 District 4, 867 District 5, 868 District 7</u> [See Guidance OPA-1]	✔		
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	✔		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	✔		
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	✔		
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]	✔		

OPA Inspection Guidance

<u>OPA-1</u> - **RSPA Tracking Number**: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

<u>OPA-2</u> - **Names and phone numbers**: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

<u>OPA-3</u> - **Proof of OSRO contract**: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

<u>OPA-4</u> - **Exercise documentation**: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

<u>OPA-5</u> - **Training records**: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1 - SCADA LIQUID WORKSHEET

Note: If the Operator has had or has been scheduled for an Integrity Management Program inspection this year, *DO NOT USE THIS WORKSHEET.*

1. **Pipeline Safety Advisory Bulletin - ADB-99-03 - July 7, 1999**
- Review Bulletin with Operator.

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. **195.402(d)(1)(iii) - Loss of communications.**
- Off-site Back-up Center
- Data transfer to redundant or off-site processors
- Battery and/or Emergency Generator
- Redundant data communications paths, automatic restoration or manual?
- Data Reduction & Archiving
- Operating practices during data communications outages

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

3. **§195.404 - Pump station discharge pressure records.**
- Discharge Pressure records in SCADA or at field locations?
- Data Reduction & Archiving
- Data acquisition frequency

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

4. **§195.404 Maps and records.**
(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:
(1) Location and identification of the following pipeline facilities:
(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c) (9) applies;
(vii) Safety devices to which §195.428 applies.
(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations
- Ensure pipeline safety parameters are current (ie: MOP, alarm set points, etc)
- Data Reduction & Archiving
- Data acquisition frequency

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

5. **§195.408 - Communications.**
(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system
(b)(1) Monitoring operational data as required by §195.402(c)(9)
- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-Short Reports
- Maintaining MOP/MAOP

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

6. **§195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance**
• Over-Short Reports
• Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

7. **§195.420 & .428 - Testing applicable SCADA controlled valves, safety devices, and overfill systems.**

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: ✔____ N:________

Comments: Operating and Maintenance Manual; Book 3; Tab 08-02-01. Hydrogen foil (where used) readings taken at least 10 times per year with intervals not exceeding 6 weeks. Effort is made to take the readings once per month. Pipeline Integrity group reviews hydrogen foil activity annually to assess overall internal corrosion mitigation and to plan remedial action if required.

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: ✔____ N:________

Comments: With the SRB's; % Organic, % In-organic. Corrosive effect is dependent on the actual flow rate in the line.

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: ✔____ N:______

Comments: A yearly injection plan is done in November after data review. The plan includes determination of when and how many injections are to be done for the next year.

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y: ✔____ N:_____

Comments: Manual reads of hydrogen foil data are done in accordance with O&M manual procedures. Some sites have remote monitoring capability and data is received daily from these locations.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: ✔_____ N:__________

Comments: The inhibitor used is a water-soluble, oil dispersible chemical. The chemical used has 2 "parts", a filmer to act as in inhibitor and a bacteria to act as a bio "killer".

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y:________N:________

Comments: N/A

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y: ✔_______ N:________

Comments: Enbridge uses 2 pigs, a "front" pig and a "back" pig. The "front" pig is a cleaning pig and the "back" pig is a sealing or batching pig (this pig ensures a uniform coating is applied on the pipe wall).

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion? Y: ✔_____ N:_______

Comments: Any examination results are noted on pipeline maintenance (PLM) reports.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

9. Does the operator track internal corrosion and take corrective action to prevent recurrence?
Y:__✔______N:_______

Comments: The entire internal corrosion program is handled through Enbridge's Pipeline Integrity Group. Enbridge has had an internal corrosion program since 1994.

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
______ Gas and Fluid analysis
______ Rates of pipeline corrosion as determined by coupons
__✔__ Solids removed from the system
__✔__ Analysis of inhibitor samples from the pipeline
______ Magnetic and electronic device (pigs)
__✔__ Other – *Hydrogen Foils*

Comments:

11. Is the inhibitor compatible with the product being transported? Y: ✔_____ N:_______

Comments: Enbridge uses extensive testing and an on-going sampling program to ensure compatibility.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge Energy

Unit: #1353 Escanaba

Date(s): 8/13 - 8/14/03

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
mp 1146.61 BV		-1.667				Valve operates ok.
mp 1149.44		-1.829	-0.963			
mp 1155.48 Hwy 112		-1.491	-0.466			
mp 1159.47 BV		-1.629				Valve operates ok.
mp 1164.66		-2.290				
mp 1169.19		-2.195				
mp 1173.17 BV		-2.195				Valve operates ok.
Rectifier				18.36	.03	
mp 1177.72		-2.460				
mp 1183.00 Saxson Station						
Sta. Rectifier				42.90	16.60	
830-RCV-1		-1.478				
5-SDV-1		-1.448				
5-CSV-12		-1.846				
5-UDV-31		-1.514				
5-USV-11		-1.855				
Pipe		-2.595				
mp 1189.21		-1.594				
mp 1189.99		-2.070				
mp 1205.12 BV		-1.455				MOV valve. Operates ok.
mp 1210.10 Rectifier				27.63	4.20	
mp 1212.18 BV		-1.090				Valve operates ok.
mp 1218.98 Rectifier				19.01	2.35	
mp 1222.05		-1.919				
mp 1226.20 Gogebic Station						
Sta. Rectifier				54.10	15.62	
1226.19-5-V		-4.320				
1226.22-5-BV		-2.212				
1226.24-5-V		-4.470				
mp 1229.68		-2.743	-0.681			
mp 1235.55		-2.300				
mp 1239.08		-2.316				
mp 1244.00 Rectifier				15.32	7.25	
mp 1247.89 BV		-1.309				Valve operates ok.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge Energy
Unit: # 1353 Escanaba
Date(s): 9/16 - 9/18/03

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1259.50		-2.526				
MP 1265.02						
Beechwood Rectifier				40.20	7.55	
MP 1272.16 Iron River Station						
Rectifier				47.50	9.40	
5-UDV-41		-2.160				
5-USV-31		-1.567				
5-USV-11		-1.393				
Sump		-4.660				
5-BV-1 (by-pass)		-3.387				
Incoming Trap		-6.730				
Outgoing Trap		-3.118				
5-BV-2 (by-pass)		-1.731				
PCV Bldg Pipe		-2.563				
Densitometer pipe		-3.455				
1272.16-5-V		-1.811				
MP 1278.50		-1.619				
MP 1287.02						
Monongahela Rectifier				11.47	2.50	
MP 1292.69 Hwy M-69		-1.749	-0.594			
MP 1299.72						
M/L BV		-1.729				Valve operates OK.
MP 1307.35						
M/L BV		-2.066				Valve operates OK.
MP 1313.84		-2.590				
MP 1316.59						
Ford River Rectifier				49.60	5.94	
MP 1318.54						
M/L BV		-2.003				Valve operates OK.
MP 1329.21						
Arnold Rectifier				25.04	2.45	
MP 1334.38						
Rectifier				5.36	0.26	
MP 1334.38						
M/L BV		-1.940				Valve operates OK.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 9/16 - 9/18/03
Unit: # 1353 Escanaba

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1341.42 GRd 523		-2.100				
MP 1343.74						
Rock Rectifier				27.20	2.70	
M/L BV		-2.164				Valve operates OK.
MP 1351.52 Hwy M-35						
Rectifier				16.62	6.21	
TS		-3.316	-1.308			
MP 1356.64 Rapid River Station						
Rectifier				32.94	6.48	
1356.69-5-V		-7.320				
5-SDV-1		-6.250				
200-AIPV-51		-4.580				
MP 1366.24		-1.440				
MP 1373.14						
M/L BV		-1.291				Valve operates ok.
MP 1379.10						
Forest Rd Rectifier				42.70	6.95	
MP 1387.58 Hwy M-149		-1.946	-0.467			
MP 1392.37 Manistique Station						
Rectifier				41.40	3.39	
1392.37-5-V		-1.354				
1392.4 - V		-1.836				
1392.42-5-V		-1.932				
PCV Bldg Pipe		-1.728				
" " "		-2.898				
5-UDV-21		-1.815				
5-USV-11		-1.176				
MP 1396.39-5-V						
M/L BV		-2.130				Valve operates OK.
MP 1406.43						
Gulliver Rectifier				35.90	5.73	
M/L BV		-2.508				Valve operates OK.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY

Unit: #1353 Escanaba

Date(s): 9/16 - 9/18/03

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1416.06		-2.182				
MP 1422.92 Gould City Station						
Rectifier				28.28	7.30	
5-USV-21		-3.737				
5-UDV-31		-2.835				
5-UDV-41		-2.762				
Densitometer pipe		-4.110				
1422.97-5-BV		-3.075				
PCV Bldg. Pipe		-2.582				
MP 1435.00 Hwy 9		-1.803				
MP 1441.36 Naubinway Station						
Rectifier A				36.40	4.08	
Rectifier B				62.40	7.32	
1441.48-5-BV		-2.576				
5-CSV-12		-2.095				
PCV Bldg Pipe		-2.004				
5-UDV-11		-2.755				
MP 1453.22						
M/L BV		-1.556				Valve operates OK.
TS		-1.955	-0.106			
MP 1460.19		-1.735				
MP 1465.50						
M/L BV		-1.278				Valve operates OK.
MP 1470.97		-1.766				
MP 1475.63 St. Ignace Station						
East Trap		-1.345				
West Trap		-1.366				
Trap from Superior		-1.389				
Flow rate pipe		-1.383				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY

Date(s): 9/16 - 9/18/03

Unit: #1353 Escanaba

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1479.55 Mackinaw Station						
Rectifier				36.37	8.96	
PCV Bldg Pipe		-2.169				
1479.55-5.1-TRV		-1.839				
1479.55-5.2-TRV		-4.920				
Trap-in		-6.670				
Trap-out		-9.840				
MP 1484.70 I-75		-1.842	-0.812			
MP 1491.70		-2.011	-0.324			
MP 1496.64						
M/L BV		-1.515				Valve operates OK.
MP 1498.81						
Topinabee Rectifier				11.14	11.80	
MP 1507.04						
M/L BV		-1.641				Valve operates OK.
MP 1514.85 Indian River Station						
Rectifier				10.96	3.80	
1514.91-5-BV		-1.949				
5-UDV-11		-1.562				
5-USV-31		-1.986				
5-UDV-41		-1.692				
PCV Bldg Pipe		-3.782				
MP 1523.99		-1.807				
MP 1532.11						
M/L BV		-1.040				Valve operates OK.
MP 1538.75		-1.600	-0.617			

Inspection Summary

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

Central Region Office **Office of Pipeline Safety**

To: Region Director *JH* **Date:** 10/6/03

P.A.
From: Phil Archuletta, Staff Engineer

Company Inspected: ENBRIDGE ENERGY, LP

Operator: ENBRIDGE ENERGY, LP

Type of Service: Interstate Liquid

Units:	**Unit I.D.**	**Inspection I.D.**
Superior	Unit #1323	103404

Dates of Inspection: 8/12/03 - 8/14/03 (field); 9/8/03 - 9/10/03 (records); 9/11/03 (field)

Location: Superior, WI (records); State of Wisconsin (field facilities)

Facilities Inspected: Phil Archuletta from CE OPS conducted a standard unit inspection of Enbridge Energy's Superior unit. The inspection was conducted using the "Standard Inspection Report of a Liquid Pipeline Carrier" inspection form. Enbridge Energy's records were reviewed at the Enbridge Energy office in Superior, WI. All documents and records requested were presented and were satisfactory.

Enbridge Energy's facilities for this unit consist of the following:

- 18", 26", 34", 36" and 48" lines from the MN/WI border to the Superior, WI terminal
- 30" line from the Superior, WI terminal to the Ino, WI Pump Station
- 24" and 34" lines from the Superior, WI terminal to the centerline of Hwy 8 north of the Ladysmith, WI Pump Station
- 5 Pump stations located at Superior, Hawthorne, Minong, Stone Lake and Edgewater (all in Wisconsin)

The actual physical facilities inspected included all of the facilities listed in the preceding paragraph.

A number of stops were made at valve settings, the single pump station and points along the pipeline segments where C/P readings could be taken.

Persons Interviewed:

Refer to the "Attendance Sheet" included with the attached "Standard Inspection Report of a Liquid Pipeline Carrier" form for a listing of persons interviewed.

Deficiencies Found:

Enbridge Energy's O&M Manuals were not evaluated. This operator had a Team O&M inspection in June, 2002.

No deficiencies were found during a review of Enbridge Energy's records and inspection of field facilities for this specific unit.

Conclusions/Recommendations:

No compliance action is required.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: ENBRIDGE ENERGY, LP

H.Q. Address:
SUITE 3300
1100 LOUISIANA
HOUSTON, TX 77002-5217

Co. Official: Mr. Dan Tutcher, President
Phone No.: 713-650-8900
Fax No.: 713-653-6711
Emergency Phone No.: 800-858-5253
Operator ID#: #11169

System/Unit Name and Address:
Superior
119 N. 25th St., East
Superior, WI 54880-4880

Phone No.:
Fax No.:
Emergency Phone No.: 800-858-5253
Unit Record ID#: 1323
Activity Record ID#: 103404

Persons Interviewed	Titles	Phone No.
Refer to attached copy of		
attendance sheet.		

OPS Representative(s): Phil Archuletta

Date(s): 8/12 – 8/14 Field
9/8 – 9/10 Records
9/11 Field

Company System Maps (copies for Region Files): YES, placed in operator file.

Unit Description:

18" LINE #1, 26" LINE #2 AND 34" LINE #3 FROM MP 1084.86 (MN / WI BORDER) TO MP 1097.77 (TERMINAL AT SUPERIOR). 30" LINE #5 FROM MP 1098.10 (SUPERIOR TERMINAL) TO MP 1137.3 (INO STA.). 30" LINE #6A FROM MP 0.0 (SUPERIOR TERMINAL) TO MP 97.23 (HWY 8 - CENTERLINE). 24" LINE #14 FROM MP 0.0 (SUPERIOR TERMINAL) TO MP 97.23 (HWY 8 – CENTERLINE).

Portion of Unit Inspected:

18" LINE #1, 26" LINE #2 AND 34" LINE #3 FROM MP 1084.86 (MN / WI BORDER) TO MP 1097.77 (TERMINAL AT SUPERIOR). 30" LINE #5 FROM MP 1098.10 (SUPERIOR TERMINAL) TO MP 1137.3 (INO STA.). 30" LINE #6A FROM MP 0.0 (SUPERIOR TERMINAL) TO MP 97.23 (HWY 8 - CENTERLINE). 24" LINE #14 FROM MP 0.0 (SUPERIOR TERMINAL) TO MP 97.23 (HWY 8 – CENTERLINE).

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections.

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description RECORDS REVIEW

Date 9/8 - 9/10 **Location** Enbridge Energy - Superior, WI Office

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	Staff Engineer	DOT Office of Pipeline Safety	(816) 329-3807	phillip.archuletta@rspa.dot.gov
2	GAIL FOLLIS	RECORDS MANAGEMENT	ENBRIDGE	(715) 394-1536	GAIL.FOLLIS@ENBRIDGE.COM
3	JAY JOHNSON	COMP COORD	"	715/394-1512	JAY.Johnson@enbridge.com
4	RANDY WILBERG	SAFETY - TRAINING COMPLIANCE	ENBRIDGE	715-394-1412	RANDY.WILBERG@ENBRIDGE.COM
5	AL ALEKNAVICIUS	MANAGER PIPELINE SERVICES	ENBRIDGE	715 394 1415	AL.ALEKNAVICIUS@ENBRIDGE.COM
6	Floyd Mott	Project Specialist	Enbridge	715-394-1506	Floyd.Mott@Enbridge.com
7	Todd Gilseth	Safety, Training Compliance	Enbridge	218-759-6615	Todd.Gilseth@Enbridge-us.com
8	Brian Pierzina	Sr. Engineer	MNOPS	218-327-4218	brian.pierzina@state.mn.us
9	Adam Erickson	Project Manager	Enbridge	715 394-1548	adam.Erickson@Enbridge.com
10	Patsy Bolk	Compliance sec.	Enbridge	715 394-1504	patsy.bolk@enbridge.com
11	WILLIAM C. CHELLEW	CORROSION TECHNICIAN	ENBRIDGE	715-394-1413	bill.chellew@enbridge.com
12	John W. Bissell	CORROSION TECHNICIAN	ENBRIDGE	715-394-1417	john.bissell@enbridge.com
13	Mark JERABEK	COMMUNICATIONS COORD.	ENBRIDGE	715-394-1538	mark.JERABEK@ENBRIDGE.COM
14	Daniel Klauer	Regional Engineer	Enbridge	715-394-1411	dan.Klauer@Enbridge.com
15	Dana Slade	Sr. Env. Analyst	Enbridge	(715) 394-1578	dana.slade@enbridge.com
16	NANCY R. BRYCE	Field Services Supervisor	ENBRIDGE	715-394-1558	nancy.bryce@enbridge.com
17	LYNNE HARRINGTON	TRAINING COORD.	ENBRIDGE	(715) 394-1642	LYNNE.HARRINGTON@ENBRIDGE.COM

8.	GREG SCHELIN	TECHNICAL SUPERVISOR	ENBRIDGE	(715) 398-8363	greg.schelin@enbridge.com
9.	DENNIS WEDAN	ASS'T. TERMINAL SUPERVISOR	ENBRIDGE	(715) 398-8323	dennis.wedan@enbridge.com
10.	RICK AUNET	TERMINAL SUPERVISOR	ENBRIDGE	(715) 398-8322	RICK.AUNET@ENBRIDGE.COM

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

HVL PIPELINE TESTING SUMMARY	N/A	Yes	No
1. Do the operator's pipelines transport HVLs?		✔	
2. Has the operator pressure tested the following "older" HVL pipelines per subpart E; or, for pipelines that have not been converted under 195.5, has the operator established these pipelines' MOP's per 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure]? **The pressure test and MOP establishment (195.406(a)(5)) deadlines for the below listed lines have passed.**		✔	
a. Onshore non low stress Interstate Lines in HVL service prior to 9/8/80 and constructed prior to 1/8/71.		✔	
b. Onshore non low stress Intrastate Lines in HVL service prior to 4/23/85 and constructed prior to 10/21/85.	✔		
c. Low stress lines in HVL service that existed on 7/12/94, or ones that were constructed before 8/11/94.	✔		

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

PIPELINE INFORMATION

Boundaries of Unit:

FROM MP 1084.86 (MN / WI BORDER) TO MP 1097.77 (TERMINAL AT SUPERIOR). FROM MP 1098.10 (SUPERIOR TERMINAL) TO MP 1137.3 (INO STA.). FROM MP 0.0 (SUPERIOR TERMINAL) TO MP 97.23 (HWY 8 - CENTERLINE).

Pipelines and Pumping Stations in Unit:

EDGEWATER, STONE LAKE, MINONG, HAWTHRONE, SUPERIOR (ALL IN WISCONSIN)

Miles of Pipeline:	Protected				Unprotected			
Steel Bare								
Steel Coated	285.3							
Other								

Breakout Tank Facilities:

SUPERIOR, WI TERMINAL

Offshore Facilities:

N/A

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Conversion to Service		S	U	N/A	N/C
.5	Has a written procedure been developed addressing all applicable requirements and followed?			✔	

Comments *(If the above is Unsatisfactory, please indicate why):*

Subpart B - Reporting Procedures			S	U	N/A	N/C
.402 (c)(2)		Does the operator have procedures for gathering data needed for reporting accidents under **Subpart B** of this part in a timely and effective manner?				✔
	.50	Does the operator file accident reports as required under 195.50? Under certain conditions, a release of more than 5 gals, or more is reported.				✔
	.52	Are certain incidents telephonically reported to the **National Response Center**?				✔
	.54	Are the incidents reported by telephone followed up with a 30-day written report?				✔
.402(f)		Does the operator have procedures for recognizing and discovery of safety-related conditions?				✔
	.55	If the operator reported a safety-related condition, did they use the proper criteria?				✔
	.56	Is there a procedure for reporting safety-related conditions?				✔
	.56(a)	Was the report filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery?				✔
	.56(b)	Was proper corrective action taken?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Subpart C - Passage of Internal Inspection Device Procedures			S	U	N/A	N/C
.402(c)/ .422	.120(a)	Has each new pipeline or each section of a pipeline which pipe or components has been replaced been designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Subpart D - Welding Procedures	S	U	N/A	N/C
		Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422, as well as §195.200.				
.402(c)/ .422	**.214(a)**	Is the welding performed in accordance with welding procedures qualified to produce welds meeting the requirements of this **Subpart**?				✔
		Has the quality of the test welds to qualify the procedures been determined by destructive testing?				✔
	.214(b)	Is each welding procedure recorded in detail?				✔
		Are welding procedures qualified in accordance with a standard that is accepted by the industry? **(API 1104, ASME Boiler & Pressure Code - Section IX, or other)**				✔
	.222	Is welding performed by welders, who have been qualified in accordance with **Section 3 of the API Standard 1104 (18th Ed., 1994)** or **Section IX of the ASME Boiler and Pressure Vessel Code (1995)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition?				✔
Alert Notice 3/13/88		**In the welding of repair sleeves and fittings, does the operator's procedures give consideration to:**				
		1. The use of low hydrogen welding rods.				
		2. Cooling rate of the weld.				
		3. Metallurgy of the materials being welded (weldability carbon equivalent).				
		4. Proper support of the pipe in the ditch.				
.402(c)/ .422	**.226(a)**	Does the operator require the repair (within pipe and (b) specification thickness tolerances) or replacement of arc burns?				✔
	.226(b)	Does the operator require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**				✔
	.226(c)	When pipe is being welded, is the ground wire attached to the pipe by other means than welding?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Welds: Acceptability - Nondestructive Testing Procedures	S	U	N/A	N/C
.402(c)/ .422	.228	Does the operator nondestructively test welds to insure their acceptability according to **Section 6 of API 1104 (18th)** and per the requirements of **§195.234** in regard to the number of welds to be tested?				✔
	.234(b)	Is nondestructive testing of welds performed:				
		1. In accordance with written procedures for **NDT**.				✔
		2. By qualified personnel.				✔
		3. By a process that will indicate any defects that may affect the integrity of the weld.				✔
	.266	Does the operator maintain records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Welds: Repair or Removal of Defect Procedures	S	U	N/A	N/C
.402(c)/ .422	.230	Does the operator remove and/or repair welds that are unacceptable in accordance with the requirements of **§195.230**?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Subpart E - Pressure Testing Procedures	S	U	N/A	N/C
.402(c)/ .422	.302(a)	Does the operator pressure test each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced?				✔
		Are lines that have not been pressure tested per subpart E being operated in accordance with this subsection?				✔
	.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195. 303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?				✔
		- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).				✔
		- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines).			✔	
		- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).			✔	
		- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).			✔	
	.303	Does the operator comply with the risk based alternative to pressure testing?				✔
	.304	The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure.				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Subpart E - Pressure Testing Procedures (Con't)	S	U	N/A	N/C
.402(c)/ .422	.305(a)	Does the operator pressure test under **§195.302** all pipe, all attached fittings, including components?				✔
	.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.				✔
	.306	Is the appropriate test medium used?				✔
	.308	Does the operator pressure test pipe associated with tie-ins as one segment or tested separately?				✔
	.310(a)	Does the operator maintain a record of each pressure test required by this **Subpart**?				✔
	.310(b)	Does the record required by paragraph **(a)** of this section include:				
	.310(b)(1)	Pressure recording charts.				✔
	.310(b)(2)	Test instrument calibration data.				✔
	.310(b)(3)	Name of the operator, person responsible, test company used, if any.				✔
	.310(b)(4)	Date and time of the test.				✔
	.310(b)(5)	Minimum test pressure.				✔
	.310(b)(6)	Test medium.				✔
	.310(b)(7)	Description of the facility tested and the test apparatus.				✔
	.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.				✔
	.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Subpart F - Operations & Maintenance Procedures	S	U	N/A	N/C
.402(a)	.402	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				✔
		b. Does the operator review the manual at intervals not exceeding 15 months, but at least each calendar year?				✔
		c. Are the manuals available, as required?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Maintenance & Normal Operation Procedures	S	U	N/A	N/C
.402(a)	.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
	.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?				✔
	.402 (c)(5)	Analyzing pipeline accidents to determine their causes?				✔
	.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?				✔
	.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?				✔
	.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?				✔
	.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?				✔
	.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards				✔
		Reporting abandoned pipeline facilities under commercially navigable waterways per §195.59				
	.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?				✔
	.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.				✔
	.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?				✔
	.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Abnormal Operation Procedures (Control Center Function)	S	U	N/A	N/C
.402(a)	.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
	.402(d)(1)	Responding to, investigating, and correcting the cause of:				
		i. Unintended closure of valves or shutdowns?				✔
		ii. An increase or decrease or flow rate outside normal operating limits?				✔
		iii Loss of communications?				✔
		iv. The operation of any safety device?				✔
		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?				✔
	.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?				✔
	.402(d)(3	Correcting variations from normal operation of pressure and flow equipment controls?				✔
	.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?				✔
	.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Emergency Procedures	S	U	N/A	N/C
.402(a)	.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
	.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				✔
	.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?				✔
	.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?				✔
	.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?				✔
	.402(e)(	Controlling the release of liquid at the failure site?				✔
	.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?				✔
	.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**?				✔
	.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments?				✔

			S	U	N/A	N/C
	.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Emergency Response Training Procedures (Control Center & Field)	S	U	N/A	N/C
.402(a)	.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to:				
	.403(a)(1)	Carry out the operating and maintenance, and emergency response procedures established under §195.402.				✔
	.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions.				✔
	.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.				✔
	.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.				✔
	.403(a)(5)	Learn the proper use of fire fighting procedures and equipment, fire suits, and breathing apparatus, etc.				✔
	.402(f)	Recognize and report safety related conditions.				✔
	.403(b)	At intervals not exceeding 15 months, but at least once each calender year:				
	.403(b)(1)	Does the operator review with personnel their performance in meeting the objectives of the emergency response training program?				✔
	.403(b)(2)	Does the operator make appropriate changes to the emergency response training program?				✔
	.403(c)	Does the operator require and verify, its supervisors maintain a thorough knowledge of the emergency response procedures they are responsible for?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

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STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Maps and Records Procedures	S	U	N/A	N/C
.402(a)	.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.				✔
	.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
	.404(a)(1)	Location and identification of the following facilities:				
		i. Breakout tanks				✔
		ii. Pump stations				✔
		iii. Scraper and sphere facilities				✔
		iv. Pipeline valves				✔
		v. Facilities to which **§195.402(c)(9)** applies				✔
		vi. Rights-of-way				✔
		vii. Safety devices to which **§195.428** applies				✔
	.404(a)(2	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.				✔
	.404(a)(3	The maximum operating pressure of each pipeline.				✔
	.404(a)(4	The diameter, grade, type, and nominal wall thickness of all pipe.				✔
	.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
	.404(b)(1)	The discharge pressure at each pump station.				✔
	.404(b)(	Any emergency or abnormal operation to which the procedures under **§195.402** apply.				✔
	.404(c)	Each operator shall maintain the following records for the periods specified:				
	.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.				✔
	.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.				✔
	.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Maximum Operating Pressure Procedures (MOP) - All Systems	S	U	N/A	N/C
.402(a)	**.406(a)**	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
	.406(a)(1	The internal design pressure of the pipe determined by **§195.106**.				✔
	.406(a)(2	The design pressure of any other component on the pipeline.				✔
	.406(a)(3	**80%** of the test pressure **(Subpart E)**.				✔
	.406(a)(4	**80%** of the factory test pressure or of the prototype test pressure for any individual component.				✔
	.406(a)(5)	**80%** of the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.				✔
	.406(b)	The pipeline may not be operated at a pressure that exceed **110% of the MOP**:				
		a. Are adequate controls and protective equipment installed to prevent the pressure from exceeding **110%** of the **MOP**?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Communication Procedures (Control Center)	S	U	N/A	N/C
.402(a)	**.408(a)**	Does the operator have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system?				✔
	.408(b)	Does the communication system required by paragraph **(a)** include means for:				
	.408(b)(	Monitoring operational data as required by **§195.402(c)(9)**.				✔
	.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.				✔
	.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.				✔
	.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Line Marker Procedures	S	U	N/A	N/C
.402(a)	.410(a)	Each operator shall place and maintain line markers over each buried pipeline in accordance with the following:				
	.410(a)(1)	Are line markers placed at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known?				✔
	.410(a)(2	Do the line markers have the correct characteristics and information?				✔
	.410(c)	Are line markers placed where pipelines are aboveground in areas that are accessible to the public?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Inspection of Rights-of-Way & Crossings Under Navigable Water Procedures	S	U	N/A	N/C
.402(a)	.412(a)	Does the operator inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**?				✔
		Does the operator follow-up on problems noted by the patrol?				
	.412(b)	Does the operator inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Underwater Inspection Procedures of Offshore Pipelines	S	U	N/A	N/C
.402(a)	.413(b)	When the operator discovers a pipeline, it operates, is exposed on the seabed or constitutes a hazard to navigation does the operator:				
	.413(b)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center.			✔	
	.413(b)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock excavation			✔	
	.57	Has the operator **filed** a report within **60 days** of the inspection as required by **§195.413**?			✔	

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Valve Maintenance Procedures	S	U	N/A	N/C
.402(a)	.420(a)	Does the operator maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times?				✔
	.420(b)	Does the operator inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year?				✔
	.420(c)	Does the operator provide protection for each valve from unauthorized operation and from vandalism?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Pipeline Repair Procedures			S	U	N/A	N/C
.402(a)	.422(a)	Does the operator, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property?				✔
	.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Pipe Movement Procedures			S	U	N/A	N/C
.402(a)	.424(a)	When moving any pipeline, does the operator reduce the pressure for the line segment involved to **50% of the MOP**.				✔
	.424(b)	For **HVL** lines **joined** by welding, does the operator:				
	.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.				✔
	.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.				✔
	.424(b)(3)	Reduce the pressure for the line segment involved to **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**				✔
	.424(c)	For **HVL** lines **not joined** by welding, does the operator:				
	.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.				✔
	.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.				✔
	.424(c)(3	Isolate the line to prevent flow of the **HVL**.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Scraper and Sphere Facility Procedures	S	U	N/A	N/C
.402(a)	.426	Does the operator, have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres?				✔
		Does the operator have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		Overpressure Safety Device Procedures	S	U	N/A	N/C
.402(a)	.428(a)	Does the operator inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable?				✔
		Does the operator inspect and test overpressure safety devices at the following intervals:				
		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.				✔
		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.				✔
	.428(b)	Does the operator inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**?				✔
	.428(c)	Do aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to the appropriate API. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual ('195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.				✔
	.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Firefighting Equipment Procedures			S	U	N/A	N/C
.402(a)	.430	Does the operator maintain adequate firefighting equipment at each pump station and breakout tank areas?				✔
	.430	The equipment must be:				
		a.. In proper operating condition at all times.				✔
		b. Plainly marked so that its identity as firefighting equipment is clear.				✔
		c. Located so that it is easily accessible during a fire.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Breakout Tank Procedures			S	U	N/A	N/C
.402(a)	.432(a)	Inspection of in-service breakout tanks. (annually/ 15mo) includes anhydrous ammonia and any other breakout tank that is not inspected per 432 (b) & (c);				✔
	.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).				✔
	.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.				✔
	.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.				✔
		Note: For Break-out tank unit inspection, refer to Breakout Tank Form				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Sign Procedures			S	U	N/A	N/C
.402(a)	.434	Does the operator maintain signs visible to the public around each pumping station and breakout tank area?				✔
		Do the signs contain the name of the operator and an emergency telephone number?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Security of Facility Procedures			S	U	N/A	N/C
.402(a)	.436	Does the operator provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Smoking or Open Flame Procedures			S	U	N/A	N/C
.402(a)	.438	Does the operator prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors?				✔

Comments *(Ifany of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Public Education Procedures			S	U	N/A	N/C
.402(a)	.440	Has the operator established a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?				✔
		Is the program conducted in English and other languages where appropriate?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Damage Prevention Program Procedures	S	U	N/A	N/C
.402(a)	.442(a)	Does the operator have a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?				✔
	.442(b)	Does the operator participate in a qualified One-Call program?				✔
	.442(c)(1)	Include the identity, on current a basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.				✔
	.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
		i. The program's existence and purpose.				✔
		ii. How to learn the location of underground pipelines before excavation activities are begun.				✔
	.442(c)(3	Provide a means of receiving and recording notification of planned excavation activities.				✔
	.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.				✔
	.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.				✔
	.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
		i. The inspection must be done as frequency as necessary during and after the activities to verify the integrity of the pipeline.				✔
		ii. In the case of blasting, any inspection must include leakage surveys.				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

		CPM/Leak Detection Procedures	S	U	N/A	N/C
.402(a)	.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

These items were not checked because the operator had a Team O & M inspection in June, 2002.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

	High Consequence Areas & Pipeline IMP Procedures	S	U	N/A	N/C
§195.450 & §195.452	These sections are being addressed by the OPS IMP group.				

	Subpart G - Operator Qualification Procedures	S	U	N/A	N/C
§195.501-509	Refer to Operator Qualification Protocols				✔

		Subpart H - Corrosion Control Procedures	S	U	N/A	N/C
.402(a)	.555	Does the Operator require and verify that supervisors maintain a through knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.				✔
	.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :				✔
		1) constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under 195.424				✔
		2) Converted under 195.5 and 3) Has an external coating that substantially meets 195.559 before the pipeline is placed in service or:				✔
		2) Is a segment that is relocated, replaced, or substantially altered.				✔
	.559	**Coating Materials;** Coating material for external corrosion control must; a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.				✔
	.561	1. All external pipe coatings required under 195.557 must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.				✔
		2. All coating damage discovered must be repaired.				✔
	.563	1. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in 195.557(a) within one (1) year?				✔
		2. Each buried or submerged pipeline converted under 195.5 must have cathodic protection if the pipeline-				✔
		1. Has cathodic protection that substantially meets 195.571 before the pipeline is placed in service, or				✔
		1. Is a segment that is relocated, replaced, or substantially altered.				✔
		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		Subpart H - Corrosion Control Procedures (Con't)	S	U	N/A	N/C
.402(a)		4. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.				✔
		5. Unprotected pipe must have cathodic protection if required by 195.573(b).				✔
	.567	Test leads installation and maintenance				✔
	.569	Examination of Exposed Portions of Buried Pipelines				✔
	.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference)				✔
	.573	1. (1) Pipe to soil monitoring (annually / 15months)				✔
		Separately protected short sections of bare ineffectively coated pipelines (every 3 years not to exceed 39 months)				✔
		(2) Before 12/29/2003 or not more than 2 years after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE RP0169-96.				✔
		2. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
		1) Determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment.				✔
		2) Before 12/29/2003 - at least once every 5 years not to exceed 63 months.				✔
		Beginning 12/29/2003 - at least once every 3 years not to exceed 39 months.				✔
		3. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - at least 6 times each year, intervals not to exceed 2 ½ months.				✔
		e. Any deficiencies identified in corrosion control must be corrected as required by				✔ ✔
	.575	Are there adequate provisions for electrical isolations?				✔
	.577	1. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects? 2. Design & install CP systems to minimize effects on adjacent metallic structures.				✔
	.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken?				✔
		2. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion				✔
		Coupons or other monitoring equipment must be examined at least 2 times each year, not to exceed 7 ½ months.				✔
		3. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe? What steps are taken to minimize internal corrosion.				✔
	.581	Are pipelines protected against Atmospheric Corrosion using required coating material. (See exception to this statement)				✔
	.583	Atmospheric corrosion monitoring -				
		ONSHORE - At least once every 3 years but at intervals not exceeding 39 months.				✔

		OFFSHORE - At least once each year, but at intervals not exceeding 15 months.				✔

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

		Subpart H - Corrosion Control Procedures (Con't)	S	U	N/A	N/C
.402(a)	.585	1. Are Procedures in place and are they followed to either reduce the MOP, or repair/replace pipe if general corrosion has reduced the wall thickness?				✔
		2. Are Procedures in place and are they followed to either reduce the MOP, or repair/replace if localized corrosion has reduced the wall thickness?				✔
	.587	Are applicable methods used in determining the strength of corroded pipe (ASME B-31G, RSTRENG)				✔
	.589	Corrosion Control Records Retention(Some are required for 5 yrs; Some are for the service life)				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*

These items were not checked because the operator had a Team O & M inspection in June, 2002.

Best Practice:
Are the breakout tanks equipped with high level alarms?

Comments: Enbridge's breakout tanks have two stages of high level alarms set at "High" and at "High – High". The "High – High" alarm is independent of the "High" alarm. The "High" level is via a tape type floating gauging system. The tape gauging system also includes a gauge near the bottom of each tank which can be used for a visual indication of the tank's level.

Note:
How often are they checked?
Is the check all the way back to the SCADA center to ensure the hardware between the sensor and SCADA is good?

Best Practice:

Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

Comments: Enbridge has recently added mailings to planning and zoning directors as part of Enbridge's program. Presentations are for county officials such as county clerks and zoning personnel.

Best Practice:

Does the operator's damage prevention program include pro-active liaison with local school officials, where the pipeline traverses or is adjacent to, school property?

Comments: Enbridge does not have a pro-active company wide program for liaison with school officials. The district level offices have some contact with schools located along Enbridge's right-of-way. Enbridge's presentation to schools is focused on school staff members and school administrative personnel.

Best Practice:

Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

Comments: Enbridge is a member of the Common Ground Alliance. Enbridge has one member of the Common Ground committee. The Common Ground study was reviewed by approximately 6 Enbridge individuals.

Best Practice:

Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

Comments: Enbridge compared Enbridge's plan to the Common Ground practices and recommendations were forwarded to the District Managers.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Best Practice:

Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

Comments: Enbridge has modified their public awareness program based on some of the practices in the Common Ground study. Enbridge now sends two people out to audit One-Call centers. The modifications done to Enbridge's damage prevention program as a result of the Common Ground Study were minor in nature.

Best Practice:

Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

Comments: Enbridge incorporates the 4 or 5 points on digging/damage prevention in the study. Enbridge looks at damage prevention as a whole process that goes beyond just "call before digging". Enbridge feels that "call before digging" should include all steps (call in, wait the required time interval, pay close attention to the pipeline company=s markers, use safe procedures while digging, etc.) Enbridge has modified their internet website to provide better public awareness.

Best Practice:

Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities?

Comments:

Best Practice:

NPRM Qualification of Pipeline Personnel
Are trained/qualified personnel used for pipeline locating & marking?

Comments: Enbridge uses only trained company employees to locate and mark lines. Line locating and marking is one of the covered tasks in Enbridge's operator qualification plan. Enbridge has 3 crossing coordinators who have attended the one week course at Staking University in Marysville, MI. These crossing coordinators then conduct field training of other Enbridge personnel. Vendors go to Enbridge field locations and train personnel on the use of specific line locating equipment.

Note: Are contractors used? What does their training consist off? How is quality control ensured when using a third party?

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Best Practice:
What factors are considered in determining the need for and timing of pigging and close interval surveys?

Comments: Enbridge uses such factors as coating type, product type, leak history, pipe type, operation history, internal inspection history, defect history and seam weld type. Enbridge uses an overlay of high resolution tool runs to determine corrosion rates to determine future intervals for tool runs. Close interval surveys are done every 5 years.

	PART 195 - FIELD REVIEW	S	U	N/A	N/C
.120	Have new pipelines, or pipeline sections of which pipe or components have been replaced, been designed and constructed to accommodate smart pigs ? (See exceptions under (b) and (c))	✔			
.262	Pumping Stations	✔			
.262	Station Safety Devices	✔			
.308	Pre-pressure Testing Pipe - Marking and Inventory	✔			
.403	Knowledge of Operating Personnel	✔			
.410	Right-of-Way Markers	✔			
.412	River Crossings	✔			
.557	Cathodic Protection (test station readings, other locations to ensure adequate CP) levels)	✔			
.573	Pipeline Components Exposed to the Atmosphere	✔			
.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds	✔			
.420	Valve Maintenance	✔			
.420	Valve Protection from Unauthorized Operation and Vandalism	✔			
.426	Scraper and Sphere Facilities and Launchers	✔			
.428	Pressure Limiting Devices	✔			
.428	Relief Valves - Location - Pressure Settings - Maintenance	✔			
.428	Pressure Controllers	✔			
.430	Fire Fighting Equipment	✔			
.432	Breakout Tanks	✔			
.434	Signs - Pumping Stations - Breakout Tanks	✔			
.436	Security - Pumping Stations - Breakout Tanks	✔			
.438	No Smoking Signs	✔			

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

	PART 195 - RECORDS REVIEW	S	U	N/A	N/C
	Conversion to Service				
.5(a)(1)	Testing to Verify MOP (ASME<Appendix N)			✔	
.5(a)(2)	Inspection of Pipeline Right-of-Way			✔	
.5(c)	Pipeline Records (Life of System)			✔	
	Pipeline Investigations			✔	
	Pipeline Testing			✔	
	Pipeline Repairs			✔	
	Pipeline Replacements			✔	
	Pipeline Alterations			✔	
	Reporting				
.52	Telephonic Reports to NRC (800-424-8802)	✔			
.54(a)	Written Accident Reports (DOT Form 7000-1)	✔			
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)	✔			
.56	Safety Related Conditions	✔			
.57	Offshore Pipeline Condition Reports			✔	
.59	Abandoned Underwater Facility Reports			✔	
	Construction				
.204	Construction Inspector Training/Qualification	✔			
.214(b)	Test Results to Qualify Welding Procedures	✔			
.222	Welder Qualification	✔			
.234(b)	Nondestructive Technician Qualification	✔			
.589	Cathodic Protection	✔			
.266	Construction Records	✔			
.266(a)	Total Number of Girth Welds	✔			
	Number of Welds Inspected by NDT	✔			
	Number of Welds Rejected	✔			
	Disposition of each Weld Rejected	✔			
.266(b)	Amount, Location, Cover of each Size of Pipe Installed	✔			
.266(c)	Location of each Crossing with another Pipeline	✔			
.266(d)	Location of each buried Utility Crossing	✔			
.266(e)	Location of Overhead Crossings	✔			
.266(f)	Location of each Valve and Test Station	✔			
	Pressure Testing				
.310	Pipeline Test Record	✔			
.305(b)	Manufacturer Testing of Components	✔			
.308	Records of Pre-tested Pipe			✔	

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

PART 195 - RECORDS REVIEW (con't)		S	U	N/A	N/C
	Operation & Maintenance				
.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions	✔			
.402(c)(10)	Abandonment of Facilities			✔	
.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Emergency Agencies	✔			
.402(c)(13)	Review of work Performed by Personnel	✔			
.402(d)(1)	Response to Abnormal Pipeline Operations	✔			
.402(d)(5)	Review of Personnel Response to Abnormal Operations	✔			
.402(e)(1)	Notices of Emergencies	✔			
.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency	✔			
.402(e)(9)	Post Accident Reviews	✔			
.403(a)	Employee Training	✔			
.403(b)	Annual Review of Personnel Performance	✔			
.403(c)	Verification of Supervisor Knowledge	✔			
.404(a)(1)	Maps or Records of Pipeline System	✔			
.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines	✔			
.404(a)(3)	MOP of each Pipeline	✔			
.404(a)(4)	Pipeline Specifications	✔			
.404(b)(1)	Pump Station Daily Discharge Pressure	✔			
.404(b)(2)	Abnormal Operations (§195.402)	✔			
.404(c)(1)	Pipe Repairs	✔			
.404(c)(2)	Repairs to Parts of the System other than Pipe	✔			
.406(a)	Establishing the MOP	✔			
.412(a)	Inspection of the ROW	✔			
.412(b)	Inspection of Underwater Crossings of Navigable Waterways	✔			
.413(b)	Inspection of Pipelines in Gulf of Mexico			✔	
.420(b)	Inspection of Mainline Valves	✔			
.428(a)	Inspection of Overpressure Safety Devices	✔			
.428(b)	Inspection of Relief Devices on HVL Tanks	✔			
.430	Inspection of Fire Fighting Equipment	✔			
.432	Inspection of Breakout Tanks	✔			
.440	Public Education	✔			

	PART 195 - RECORDS REVIEW (Cont.)	S	U	N/A	N/C
	Damage Prevention Program				
.442(c)(1)	List of Current Excavators	✔			
.442(c)(2)	Notification of Public/Excavators	✔			
.442(c)(3)	Notifications of planned excavations. (One -Call Records)	✔			
	Corrosion Control				
.569	Inspection of Exposed Pipelines (External Corrosion)	✔			
.573(a)	External Corrosion Control - Protected Pipelines	✔			
.573(b)	External Corrosion Control - Unprotected Pipelines			✔	
.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	✔			
.579(a)	Corrosive effect investigation	✔			
.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment			✔	
.579(c)	Inspection of Removed Pipe for Internal Corrosion	✔			
.589	Cathodic Protection (Maps showing anode location, test stations, CP systems, etc)	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Oil Pollution Act High Impact Inspection (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number 865 District 3, 866 District 4, 867 District 5, 868 District 7 [See Guidance OPA-1]	✔		
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	✔		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	✔		
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	✔		
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]	✔		

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Attachment 1 - SCADA LIQUID WORKSHEET

Note: If the Operator has had or has been scheduled for an Integrity Management Program inspection this year, *DO NOT USE THIS WORKSHEET.*

1. **Pipeline Safety Advisory Bulletin - ADB-99-03 - July 7, 1999**

- Review Bulletin with Operator.

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

Operators may choose to use SCADA, or other forms of automation, to comply with the Pipeline Safety Regulations. The following code subsections could apply if a SCADA system is utilized:

2. **195.402(d)(1)(iii) - Loss of communications.**

- Off-site Back-up Center
- Data transfer to redundant or off-site processors
- Battery and/or Emergency Generator
- Redundant data communications paths, automatic restoration or manual?
- Data Reduction & Archiving
- Operating practices during data communications outages

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

3. **§195.404 - Pump station discharge pressure records.**

- Discharge Pressure records in SCADA or at field locations?
- Data Reduction & Archiving
- Data acquisition frequency

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

4. **§195.404 Maps and records.**
(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:
(1) Location and identification of the following pipeline facilities:
(i) Breakout tanks;
(ii) Pump stations;
(iii) Scraper and sphere facilities;
(iv) Pipeline valves;
(v) Facilities to which §195.402(c) (9) applies;
(vii) Safety devices to which §195.428 applies.
(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

- Ensure SCADA screens/status board are updated to reflect current pipeline configurations
- Ensure pipeline safety parameters are current (ie: MOP, alarm set points, etc)
- Data Reduction & Archiving
- Data acquisition frequency

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

5. **§195.408 - Communications.**
(a) Communication system must provide for the transmission of information needed for the safe operation of its pipeline system
(b)(1) Monitoring operational data as required by §195.402(c)(9)
- Status Monitoring
- Alarm Thresholds
- Alarm Management
- Event Log
- Over-Short Reports
- Maintaining MOP/MAOP

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

Attachment 1 - SCADA LIQUID WORKSHEET

6. **§195.134 & 444 - Computational Pipeline Monitoring (CPM) leak detection design & maintenance**

- Over-Short Reports
- Must Comply with API 1130 requirements in operating, maintaining, testing, record-keeping, and dispatcher training.

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

7. **§195.420 & .428 - Testing applicable SCADA controlled valves, safety devices, and overfill systems.**

Comments: This worksheet was not completed because the Operator was scheduled for an Integrity Management Program inspection during 2003.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

NOTE: Refer to OPS Enforcement Manual, Code Compliance Guidelines PART 195, SUBPART H: CORROSION CONTROL for Internal Corrosion

1. Are internal corrosion control procedures established? Y: ✔____ N:________

Comments: Operating and Maintenance Manual; Book 3; Tab 08-02-01. Hydrogen foil (where used) readings taken at least 10 times per year with intervals not exceeding 6 weeks. Effort is made to take the readings once per month. Pipeline Integrity group reviews hydrogen foil activity annually to assess overall internal corrosion mitigation and to plan remedial action if required.

2. Has the operator investigated the corrosive effect of the hazardous liquid or carbon dioxide; and has he taken adequate steps to mitigate internal corrosion? Y: ✔____ N:________

Comments: With the SRB's; % Organic, % In-organic. Corrosive effect is dependent on the actual flow rate in the line.

3. Does operator inject corrosion inhibitor to mitigate internal corrosion? Y: ✔_____ N:______

Comments: A yearly injection plan is done in November after data review. The plan includes determination of when and how many injections are to be done for the next year.

4. Each coupon utilized or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 ½ months. Y: ✔_____ N:_____

Comments: Manual reads of hydrogen foil data are done in accordance with O&M manual procedures. Some sites have remote monitoring capability and data is received daily from these locations.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

5. Does operator control internal corrosion effects caused by water by dehydration and water-soluble inhibitors? Y: ✔_____ N:_________

Comments: The inhibitor used is a water-soluble, oil dispersible chemical. The chemical used has 2 "parts", a filmer to act as in inhibitor and a bacteria to act as a bio "killer".

6. Does the operator have the means to monitor free oxygen introduced into the transported commodity, which may adversely affect breakout tanks or pipelines? Y:________N:________

Comments: N/A

7. Does the operator pig their pipelines to remove any water or sludge build-ups (sample analysis should be performed)? Y: ✔______ N:________

Comments: Enbridge uses 2 pigs, a "front" pig and a "back" pig. The "front" pig is a cleaning pig and the "back" pig is a sealing or batching pig (this pig ensures a uniform coating is applied on the pipe wall).

8. Whenever pipe is removed (including coupons removed during hot taps), is it examined for evidence of internal corrosion? Y: ✔_____ N:_______

Comments: Any examination results are noted on pipeline maintenance (PLM) reports.

Attachment 2 - INTERNAL CORROSION WORKSHEET - LIQUID PIPELINES

9. Does the operator track internal corrosion and take corrective action to prevent recurrence?
Y:__✔______N:_______

Comments: The entire internal corrosion program is handled through Enbridge's Pipeline Integrity Group. Enbridge has had an internal corrosion program since 1994.

10. Which method does the operator utilize to determine the effectiveness of its corrosion inhibition program?
______ Gas and Fluid analysis
______ Rates of pipeline corrosion as determined by coupons
__✔___ Solids removed from the system
__✔___ Analysis of inhibitor samples from the pipeline
______ Magnetic and electronic device (pigs)
__✔___ Other – *Hydrogen Foils*

Comments:

11. Is the inhibitor compatible with the product being transported? Y: ✔_____ N:_______

Comments: Enbridge uses extensive testing and an on-going sampling program to ensure compatibility.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge Energy

Unit: #1323 Superior

Date(s): 8/12/03

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
MP 1087.09						
BV E 1087.09-3-V	Line 3	-1.156				
BV E 1087-00-4-V	Line 4	-1.201				
Line 4 @ densitometer takeoff		-1.078				
MP 1089.99	Line 1	-1.290				
	Line 2	-1.314				
	Line 3	-1.284				
	Line 4	-1.322				
MP 1093.80						
BV E 1093.80-4-V	Line 4					MOV valve. Operates OK.
Note: Following data is for Superior to Ladysmith						
MP 5.60	Line 6	-1.419				
	Line 14	-1.437				
MP 13.55	Line 6	-1.342				
	Line 14	-1.440				
MP 20.04	Line 6	-1.600				
	Line 14	-1.550				
MP 23.62 Hawthorne Station						
Sta. Rectifier				17.04	4.40	
Inlet to Pump House		-2.226				
Outlet from Pump House		-2.083				
MP 30.00						
Rectifier				88.30	3.80	
	Line 6	-2.494	-0.100			
	Line 14	-2.522				
MP 33.90 BV						
St. Croix River						
- South side		-1.110				MOV valve. Operates OK.
	Line 6	-1.565	-0.181			
	Line 14	-1.160				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge Energy

Unit: #1323 Superior

Date(s): 8/12/03

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 41.23 Minong Station						
Sta. Rectifier				75.40	9.15	
MN-6-UDV-11		-1.801				
MN-6-USV-41		-2.101				
C 41.24-6-V		-6.730				
MN-6-SSV-1		-4.170				
MP 47.61	Line 6	-0.956	-0.673			
Hwy 77	Line 14	-1.099				
MP 55.58						
Line 6 BV		-1.448				Valve operates OK.
Line 14 BV		-1.320				MOV valve. Operates OK.
MP 61.80 Stone Lake Station						
Sta. Rectifier				57.70	4.85	
Outlet pipe		-5.110				
Inlet pipe		-5.950				
6-SSV-1		-1.200				
C61.84-6-BV		-1.087				
6-SDV-1		-1.252				
MP 70.08 Edgewater Station						
Sta. Rectifier				51.20	19.68	
Inlet pipe	Line 14	-3.177				
Inlet to P.H.	Line 14	-1.929				
EG-6-USV-11		-2.339				
EG-6-UDV-41		-1.819				
CV area		-1.989				
MP 79.24	Line 6	-1.700	-0.555			
Hwy 48	Line 14	-2.157				
MP 88.18 Chippawah River - North side						
Line 6 BV		-1.070				Valve operates OK.
Line 14 BV		-1.076				MOV Valve. Operates OK.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Enbridge Energy
Unit: # 1323 Superior
Date(s): 8/14/03

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
Note: Following data is for Superior to Ino Station (Line 5 only)						
MP 1098.54 BV		-1.254				MOV valve. Operates OK.
MP 1100.37		-1.130	-0.504			
MP 1105.98 BV		-1.126				Valve operates ok.
MP 1110.40 BV		-1.306				Repair indicator rod.
MP 1115.55 BV		-2.086				
Rectifier				8.12	8.20	
@ TS		-2.238	-1.077			
MP 1122.60 Hwy H		-0.984	-0.623			
MP 1127.62 BV		-1.353				MOV valve. Operates OK.
MP 1137.32 Ino Station						
Sta. Rectifier				64.00	6.27	
1137.34-5-BV		-1.447				
Unit 2 Discharge		-2.055				
Sump		-1.382				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY

Unit: # 1323 Superior

Date(s): 9/11/03

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
TANK #4	N	-2.742				
	S	-2.869				
	E	-2.565				
	W	-2.620				
	Rectifier			8.15	34.20	
TANK #2	N	-1.601				
	S	-1.550				
	E	-1.353				
	W	-1.411				
	Rectifier			7.42	35.10	
TANK #26	#1	-3.111				
	#2	-4.026				
	#3	-4.028				
	#4	-2.320				
	#5	-3.747				
	Rectifier			7.66	10.80	
TANK #8	N	-2.095				
	S	-1.944				
	E	-1.786				
	W	-2.239				
	Rectifier			8.83	44.4	Rectifier shared with TANK #6
TANK #12	N	-1.370				
	S	-1.553				
	E	-1.412				
	W	-1.527				
	Rectifier			7.18	31.40	Rectifier shared with TANK #10
TANK #6	N	-2.278				
	S	-2.041				
	E	-2.232				
	W	-2.064				
	Rectifier			8.83	44.4	Rectifier shared with TANK #8

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY **Date(s):** 9/11/03
Unit: # 1323 Superior

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Rectifier Amps	Remarks
TANK #10	N	-2.040				
	S	-1.757				
	E	-1.473				
	W	-1.890				
	Rectifier			7.18	31.40	Rectifier shared with TANK #12
TANK #30	#1	-1.278				
	#2	-2.855				
	#3	-4.590				
	#4	-1.664				
	#5	-5.910				
	#6	-2.704				
	#7	-3.078				
	#8	-2.138				
	#9	-1.569				
	#10	-0.566				Possible bad wire.
	Rectifier			12.70	11.60	
TANK #32	L3	-1.566				This is a new tank and
	L42	-0.561				rectifier and the rectifier
	L82	-0.738				has not been fully adjusted
	L122	-1.073				and balanced. CP technician
	L159	-1.575				still working on the system.
	R3	-1.049				
	R42	-0.732				
	R82	-0.990				
	R122	-0.587				
	R159	-1.273				
	Rectifier			4.37	8.05	
TANK #16	N	-1.684				
	S	-1.747				
	E	-1.758				
	W	-1.755				
	Rectifier			8.07	42.90	Rectifier shared with TANK #18

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY
Unit: #1323 Superior
Date(s): 9/11/03

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
TANK #20	N	-1.659				
	S	-1.532				
	E	-1.664				
	W	-1.635				
	Rectifier			6.93	36.00	Rectifier shared with TANK #22
TANK # 18	N	-1.840				
	S	-2.575				
	E	-2.822				
	W	-2.821				
	Rectifier			8.07	42.90	Rectifier shared with TANK # 16
TANK #22	N	-2.720				
	S	-2.439				
	E	-2.754				
	W	-2.608				
	Rectifier			6.93	36.00	Rectifier shared with TANK # 20
TANK #24	N	-1.529				
	S	-1.312				
	E	1.376				
	W	-1.380				
	Rectifier			7.04	30.00	
TANK # 14	N	-1.545				
	S	-1.626				
	E	-1.560				
	W	-1.685				
	Rectifier			6.84	43.20	
Injection pump @ NGL bullets		-1.094				
Bullet PR 1.1		-1.126				
Bullet PR 1.2		-1.212				
#1 Manifold Bldg	18"	-1.355				
	26"	-1.350				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: ENBRIDGE ENERGY
Date(s): 9/11/03
Unit: #1323 Superior

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
#5 out going trap		-1.297				
#5 meter skid pipe		-1.385				
5-USV-21		-1.112				
5-UDV-41		-1.256				
#5 PCV Bldg pipe		-1.447				
20" 161-FDV-001		-1.269				
20" Prover Loop		-1.242				
20" OVIC		-1.486				
#6 -USV-41		-1.192				
6-UDV-21		-1.162				
6-USV-11		-1.216				
Sump		-1.192				
6-CSV-21 PCV Bldg		-1.426				
800-PSV-1		-1.153				
812-RLV-12		-1.322				
813-PSV-21		-1.237				
New valve @ L4 relief		-1.317				
L4 manifold relief		-1.300				
L1 PCV Bldg pipe		-1.054				
Rectifier 1097 H				24.22	12.10	
Rectifier 1097 F				23.75	20.00	
L2 PCV Bldg pipe		-1.397				
26" Receiver trap		-1.550				
18" Receiver trap		-1.564				
Rectifier 1097 Q				28.35	15.50	
36" Trap		-1.393				
817-RLV-21	36"	-1.354				
meter run	36"	-1.375				
34" Trap		-1.401				
Rectifier 1097 K				22.36	10.70	

ACTID 103248

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
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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

October 24, 2003

Case No. 004016-1

Mr. Ivan Huntoon, Central Region Director
Federal Office of Pipeline Safety
901 Locust Street, Room 462
Kansas City, MO 64106

INTERSTATE AGENT INSPECTION REPORT
Specialized Inspection 430 - 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: This case relates to the dig program established by Enbridge Energy Company on the 34 inch Line 3 crude oil pipeline, following the July 4, 2002, rupture near Cohasset, Minnesota, and subsequent internal inspections.

KEY INFORMATION:

Inspection Unit:	OPID 11169, Federal System 152 CE System 1, OPS Unit ~~3803~~, 3083 MNOPS Units 153161 & 153162
Company HQ:	Enbridge Energy Company, Inc. 1100 Louisiana, Suite 2950 Houston, TX 77002-7002
MNOPS Inspectors:	Brian Pierzina, Darren Lemmerman, Steve Sweney, Boyd Haugrose
OPS Inspectors:	None
AFO Days:	28
Inspection Dates:	BEP – January 17, 21, 24, 27, 29, 31, February 3, 4, 5, 6, 7, 19, 20, 21, 24, 25, 27, March 3, 4, 6, 10, 27, April 1, 2003; BEH – January 29, 2003; DKL – January 28-29, 2003; SMS – January 28-29, 2003
Persons Interviewed:	Jay Johnson – Operations Services Coordinator Tim Anderson – Project Coordinator Larry Sand – Project Coordinator

INSPECTION OVERVIEW:

This case relates to the 34 inch crack investigations conducted by Enbridge, following the July 4, 2002 rupture, near Cohasset, Minnesota (MNOPS Case no. 3656). As part of the return-to-service plan, Enbridge conducted an internal inspection of the pipeline from Clearbrook, Minnesota, to Superior, Wisconsin, using both MFL and UT technology. The portion of the pipeline from Gretna, Manitoba, to Clearbrook, Minnesota, had been internally inspected prior to the rupture.

The in-line inspection (ILI) results identified numerous defects, including crack like indications, hook defects, and stress corrosion cracking (SCC), and Enbridge implemented a comprehensive dig program to investigate and repair these anomalies. Linear indications were evaluated in the field through an independent non-destructive testing (NDT) firm, utilizing FAST ultrasonic testing, and magnetic particle inspection.

Some shallow external defects were repaired by grinding until the defect was removed. In locations where a significant amount of shallow SCC was present, the pipe was sleeved, in order to expedite the repair.

The SCC is a relatively new integrity concern on this pipeline, as it had not been identified previously. The deepest SCC identified as a result of the program was 82%, which was confined to a relatively small area. The majority of the SCC identified was much shallower, but covered a much broader area.

The results of this program have been presented to MNOPS and OPS by Enbridge a number of times, with the most recent meeting being August 14, 2003. There is additional work to do concerning "notch-like" defects, which for the most part were not given depth estimates by the ILI vendor. Because some of these defects have been significant, and because there are so many of them, Enbridge is working with the tool vendor to obtain depth estimates, in order to prioritize those requiring investigation.

During a unit inspection of Enbridge, the week of September 8-12, 2003, results of a similar crack detection inspection for the 26 inch pipeline were reviewed. It was discovered that the 26 inch ILI/dig program identified a 10.5 inch long defect that was up to 74% through wall, consisting of a primary defect that was ID connected (64%), with some coincidental external defects that were approximately 7-8% through wall (refer to copies of NDE results enclosed). The ILI tool was run in this section of the pipeline June 26, 2001, with the initial report received by Enbridge in November, 2001. However, Enbridge only requested the first 15 km downstream from each station, and this particular defect (MP 1055.8367) was just outside of that target area. The full report was received by Enbridge in July, 2002, but this defect was not investigated/repaired until April, 2003.

Even though this defect was on 26 inch A.O. Smith pipe, it illustrates some of MNOPS' concerns with the potential to miss an injurious defect. The defect was called out as a 6.6 inch long, internal, notch-like, weld anomaly, with no depth estimate. The fact that it was not dug for close to ten months following receipt of the report, and almost two years since the tool was run, indicates there were not too many people getting excited about this anomaly. But in the end, it was one of the more severe defects identified on either the 26 inch or the 34 inch pipelines. It could also be possible the defect grew in service from the time the tool was run until the time it was investigated. We believe there is value in further investigating the circumstances surrounding the identification and investigation of this defect, as it may present an example of some of the difficulties associated with analysis of tool results.

There were no violations identified as a result of the above inspections. MNOPS appreciates the opportunity to assist in the integrity assessment process, and looks forward to continued involvement in these efforts.

Prepared by,

Brian E. Pierzina

_________________________ Brian Pierzina, Senior Engineer

For the Minnesota Office of Pipeline Safety,

Charles R. Kenow

_________________________ Charles R. Kenow, Administrator

cc: Leonard Steiner, OPS

enclosure

SPIN LLC
Sikorski & Plamenatial Innovative NDE

ENBRIDGE PIPELINES (LAKEHEAD) LLC
Inline Inspection Tool Correlation NDE Report
PII CD Tool Run - November 2002

Area Number: **21-04282**	Milepost: **1055.84**
Station: **14895+75.97**	Upstream Girth Weld #: **83060**

Project: NDE and Inspection - Crack Excavations
Pipeline System: 26" Dia. Line 2
Segment: Clearbrook to Superior

	US Joint	Anomaly Joint	DS Joint	OK?
Jt length	NA	NA	NA	ENB
O'clock	NA	10:00	NA	ENB

Axial Length of Pipe Examined: 10.00 ft.
Axial Start: 22.00 End: 32.00

Seam Type: SSAW [ ] FW [X] ERW [ ] DSAW [ ] SMLS [ ]
Coating Type: Coal Tar [X] FBE [ ] Tape [ ]

Actual Profile Data: T1 0.277 T2 0.280 TW 0.366 WW 0.290 WH 0.120

NDE Methods
Visual [X] WCAMT [X] UT-FAST [X] UT- 0 Degree [X] UT Shear [ ] WFMAT [ ]

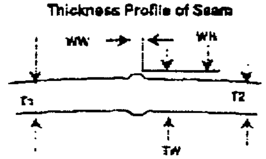
Anomaly Information

Area Number	Called Start (ft)	Called Length (in)	Called Radial Pos. (Clock)	Max Thick. @ Ind.	Actual End	Actual Start	Actual Radial Pos. (Deg)	Actual Length (in)	Max Depth (in)	Max Depth (%)	Weld or Base Metal	ID/OD	Defect Type	Grind Length	Comments and Notes
21-04282	26.74	6.80	10:00	0.366	27.53	26.65	300.00	10.56	0.235	64.2%	Weld	ID	CK	NA	CK in weld
NA	NA	NA	NA	0.366	26.05	25.94	300.00	1.32	0.028	7.7%	Weld	OD	CK	NA	CK in weld
NA	NA	NA	NA	0.366	26.51	26.40	300.00	1.32	0.028	7.7%	Weld	OD	CK	NA	CK in weld
NA	NA	NA	NA	0.366	27.29	27.10	300.00	2.28	0.028	7.7%	Weld	OD	CK	NA	CK in weld

NDE Remarks:

Percent Through Data for SCC Fields is the Max detected area. In addition, the entire long seam was examined with WCAMT, all indications revealed were addressed.

Thickness Profile of Seam



NDE Anomaly or Flaw Type Abreviations

CK I NF GR GI GA DS DB CD CP CS O NA

Meets Criteria: [ ] Fails Single: [X] Fails Combo: [ ]

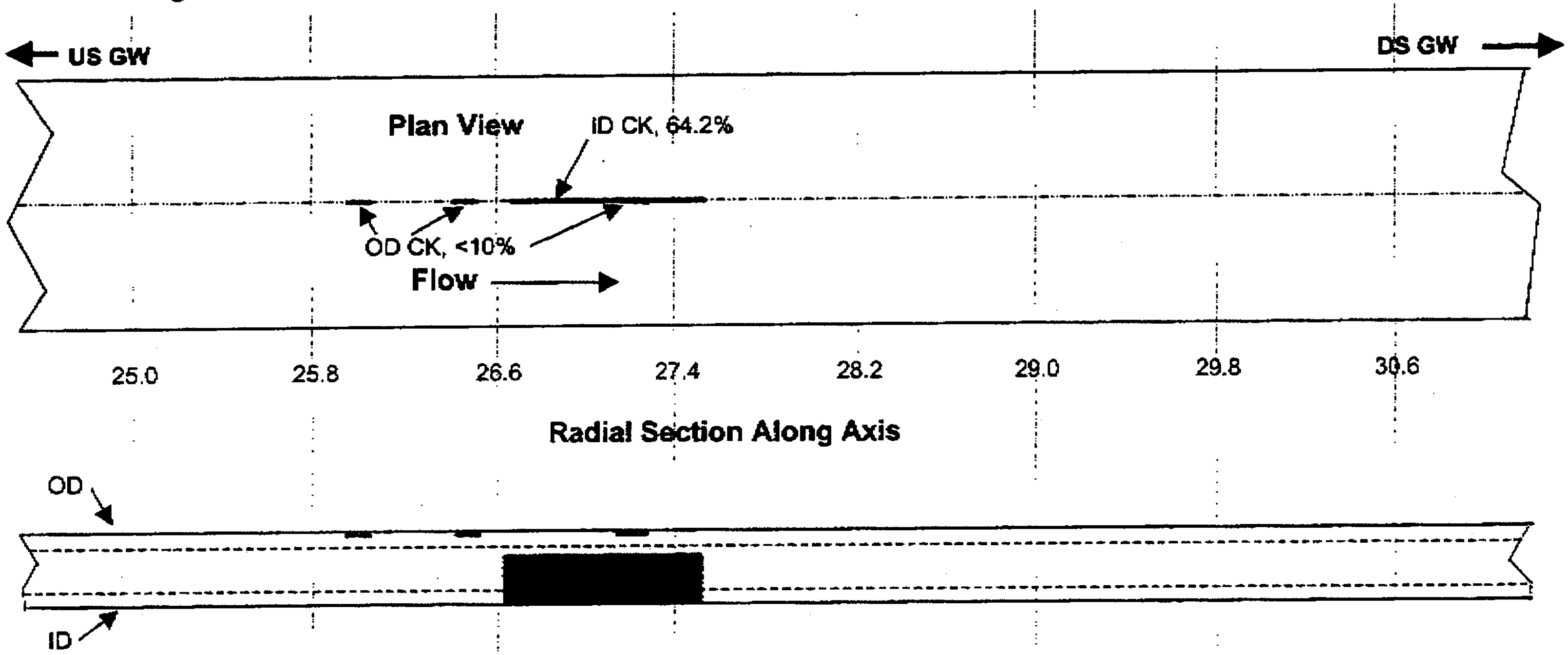
Date of Exam	Technician (Print)	Technician (Sign)	Acknowledgement of Reciep:	Client Review	Date of Review
4/2/2003	Mike Redmond				

34" OD Seam Welded Pipe

NDE Examination of Long Seam Graphical Representation of Results

Mile Post: 926.19
Pipe Number: 2311
Stationing: 8050+57

Nominal Wall Thk: 0.281 **Seam Type:** SSAW



Technician Mike Redmond Date 2-Apr-2003 Page 2 of 4

Enbridge Pipelines Inc.

2001-2002 Crack Excavation Program Line 2 - 26" Gretna to Superior

				Repair	ILI Information							Field Information					
Milepost	Girthweld	Nominal Wall Thickness (in)	Pipe Manufacturer	Type of Repair Required	Feature Area Number	Feature Length (in)	Feature Depth (%)	Relative Position	Radial Position of Feature (Int/Ext)	Type	Comments	Feature Length (in)	Max. Feature Depth (%)	Indication Relative Position	Radial Position of Feature (Int/Ext)	Indication Type	Comments
775.0932	4290	0.281	AO Smith	Recoat	01-13125	9.20		bm	Ext	il	strong; near GW; lamination	60+	N/A	BM	Ext	IL	Lamination
812.8746	56990	0.281	AO Smith	Recoat	07-05914	8.70		bm	Ext	il	strong; slivers	3.00	5%	BM	Ext	NL	gouge
821.8059	68670	0.281	AO Smith	Recoat	08-27381	32.90		aw	Ext	ml	at GW; possibly with minor cracks	N/A	N/A	N/A	N/A	N/A	Scatter and intermittent (very small) inclusions at the mid wall in pipe body in feature area
821.8609	69670	0.281	AO Smith	Recoat	08-17894	1.50		bm	Ext	il	strong; slivers	3.00	5%	BM	Ext	NL	gouge
872.5223	70620	0.281	AO Smith	Sleeve	08-20810	6.20		aw	Int	nl	possibly weld defect	6.37	42%	IW	Int	CL	
		0.281										1.50	25%	IW	Int	CL	
		0.281										2.50	30%	IW	Int	CL	
		0.281			08-20804	3.10		iw	Int	nl	possibly weld defect	3.60	39%	IW	Int	CL	
		0.281										1.00	20%	IW	Int	CL	
		0.281			08-20809	4.60		iw	Int	nl	possibly weld defect	4.75	36%	IW	Int	CL	
		0.281										7.50	27%	IW	Int	CL	
		0.281										4.80	33%	IW	Int	CL	
		0.281			08-20811	7.90		iw	Int	nl	intermittment, possibly weld defect	10.70	27%	IW	Int	CL	
		0.281			08-27393	6.80		iw	Int	nl	intermittment, possibly weld defect	5.80	27%	IW	Int	CL	Intermittent linear indications
		0.281										1.20	25%	IW	Int	CL	
		0.281										1.30	30%	IW	Int	CL	
		0.281			08-20815	3.20		iw	Int	nl	intermittment, possibly weld defect	1.50	25%	IW	Int	CL	
		0.281										1.00	25%	IW	Int	CL	
		0.281										1.00	20%	IW	Int	CL	
		0.281										0.80	20%	IW	Int	CL	
		0.281										1.90	33%	IW	Int	CL	
		0.281										2.20	30%	IW	Int	CL	
		0.281										0.70	20%	IW	Int	CL	
850.7567	109780	0.281	AO Smith	Sleeve	04-10016	1.70		iw	nd	nl	possibly weld defect, strong	1.50	60%	IW	Int	CL	Linear indication
		0.281										1.25	35%	IW	Int	CL	Linear Indication
		0.281										2.60	30%	IW	Int	CL	Linear Indication
897.9708	175080	0.281	AO Smith	Sleeve	10-15890	4.00		aw	Int	nl	possibly weld defect; strong	4.00	50%	IW	Int	CL	Linear Indication
909.7800	730	0.281		Recoat	01-02038	6.30	12.5-25	aw	e	cl	under sleeve; cr weld lhg; V: cl 1.3 mm	N/A	N/A	N/A	N/A	N/A	Nothing found
		0.281			01 02038	16.40	25-40	aw	e	cl	near GW; cl weld lhg; similar area A02039; V: no indication	N/A	N/A	N/A	N/A	N/A	Nothing found
909.8600	830	0.281		Recoat	01-02298	2.60		aw	e	nl	near GW; probably indication from weld; ERW	23.50	<10%		Int	Geo	Sporadic ID gouging
912.0700	3650	0.281		Grind	01-08645	10.80		bm	e	nl		34.00	<10%		Ext	Geo	OD gouge
912.6800	4680	0.281		Recoat	01-11536	20.80		aw	e	nd	weld defect or weld lhg; V: no indication	N/A	N/A	N/A	N/A	N/A	Nothing found
914.4900	7130	0.281		Recoat	02-02566	6.10		aw	e	nl	near GW; probably indication from weld; ERW	N/A	N/A	N/A	N/A	N/A	Nothing found
914.5000	7140	0.281		Recoat	02-02604	3.60		aw	e	ml	possibly with minor cracks; or inclusion-like	N/A	N/A	N/A	N/A	N/A	Nothing found
916.4500	9570	0.281		Recoat	02-13980	50.90		bm	i	nl	near GW	42.00	<10%	BM	Int	Geo	Intermittent ID gouge
916.4600	9590	0.281		Grind	02-13987	16.50		bm	nd	geo	dent	8.00	1.38%	BM		Geo	Shallow gouge in dent
917.2700	10710	0.281		Recoat	02-13989	53.80		aw	e	nl	probably indication from weld; ERW	1.25	<10%	AW	Ext	Geo	OD gouge, likely from mill
		0.281		Recoat	02-11597	34.10		aw	e	nl	weld lhg; probably indication from weld; ERW; cont. of area B13989	1.00	<10%	AW	Ext	Geo	OD gouge, likely from mill
		0.281		Recoat	02-11599	53.30		aw	e	nl	probably indication from weld; ERW	N/A	N/A	N/A	N/A	N/A	
		0.281		Recoat	02-11605	10.80		aw	e	nl	probably indication from weld; ERW	N/A	N/A	N/A	N/A	N/A	
918.9166	13180	0.281	AO Smith	Recoat	C16893	19.84		bm	Ext	geo	dent; with ml; possibly with minor cracks;	24.00	1.2%	BM	Ext	Dent	Dent
929.6180	27750	0.281	AO Smith	Recoat	E07743	5.59	<12.5	bm	Ext	il	sliver?;	36.00	10%	BM	Ext	Mech	Gouge
933.1480	32600	0.281	AO Smith	Sleeve	06-03044	24.20		iw	i	nl	Int; weld anomaly;	3.00	31.0%	IW	Ext	CL	ID Connected in weld
												16.00	20.0%	IW	Ext	CL	ID connected in weld
948.5149	54090	0.281	AO Smith	Recoat	09-05845	8.30		aw	i	nl	stg;	8.10	5.0%	AW	Int	GEO	ID gouge
		0.281	AO Smith	Recoat	09 05853	8.30		aw	i	nl	stg;	9.50	5.0%	AW	Int	GEO	ID gouge
949.2136	55040	0.281	AO Smith	Sleeve	107878	7.72	12.5-25	iw	Int	cl	weld anomaly;	8.10	30%	IW	Int	CL	Linear indication, Sample installed for cut out, Sent to CC Tech - verified Hook Crack
953.6300	61590	0.281		Recoat	10-10598	39.60		aw	e	nl	probably indication from weld; ERW	N/A	N/A	N/A	N/A	N/A	
		0.281			10-10601	19.60		aw	e	nd	cl or weld lhg	60.00	<10%		Int/Ext	Geo	gouge
954.7700	62760	0.281		Recoat	11-02613	14.90		aw	nd	nl	probably indication from weld; ERW	N/A	N/A	N/A	N/A	N/A	Nothing found
955.4200	63790	0.281		Sleeve	11 04749	4.00		aw	e	nd	cl or weld lhg	4.00	65%	AW	Int	CL	ID connected crack
956.4800	65250	0.281		Sleeve	11-07806	4.90		aw	e	nd	cl or weld lhg	5.50	40%	AW	Ext	CL	OD connected crack
957.3700	66000	0.281		Sleeve	12 00364	10.70		aw	i	nd	cl or weld lhg	10.25	33%	AW	Int	CL	ID connected crack
957.8900	66990	0.281		Grind	12-10519	26.90		bm	nd	nd	cl or surface lhg	1.00	<5%	BM			1-1/2" long arc burn
960.4200	70790	0.281		Recoat	12-09230	7.20		aw	i	nd	cl or weld lhg	6.50	33%	AW	Int	CL	Cut coupon out. ID connected crack
962.9724	74320	0.281	AO Smith	Sleeve	M07672	3.19		bm	Ext	nl	nGW; stg; clp;	13.00	10%	BM	Ext	NL	Gouge on OD of Pipe
963.9663	75660	0.281	AO Smith	Sleeve	M11884	4.40		iw	Int	nl	weld anomaly;	6.00	25%	IW	Int	CL	Linear Indication
964.4945	76400	0.281	AO Smith	Recoat	M17360	20.78	25-40	bm	Ext	cl	nGW; slivers;	28.00	12%	BM	Ext	Il	Several parallel laps
964.7589	76770	0.281	AO Smith	Sleeve	M14934	3.73		iw	Int	nl	weld anomaly;	4.00	35%	IW	Int	CL	Linear Indication

Enbridge Pipelines Inc.

2001-2002 Crack Excavation Program Line 2 - 26" Gretna to Superior

				Repair	ILI Information							Field Information					
Milepost	Girthweld	Nominal Wall Thickness (in)	Pipe Manufacturer	Type of Repair Required	Feature Area Number	Feature Length (in)	Feature Depth (%)	Relative Position	Radial Position of Feature (Int/Ext)	Type	Comments	Feature Length (in)	Max. Feature Depth (%)	Indication Relative Position	Radial Position of Feature (Int; Ext)	Indication Type	Comments
												6.00	35%	IW	Int	CL	Linear Indication
965.7711	78100	0.281	AO Smith	Sleeve	N01328	8.69		iw	Int	nl	weld anomaly;	3.00	40%	IW	Int	CL	Linear Indication
966.4814	79050	0.281	AO Smith	Sleeve	N04238	2.93		iw	Int	nl	weld anomaly;	10.00	40%	IW	Int	CL	Linear Indication
966.0681	79580	0.281	AO Smith	Sleeve	N06047	10.52		aw	Int	nd	cl or weld ihg;	3.00	35%	IW	Int	CL	Linear Indication
968.5326	81920	0.281	AO Smith	Sleeve	N12566	3.46		iw	Int	nl	weld anomaly;	3.80	16%	AW	Ext	CF	SCC
980.4307	98070	0.281	AO Smith		17 00317	3.50		bw	o	ml	possibly with minor cracks;	2.20	35%	IW	Int	CL	Hook defect
982.5209	100930		AO Smith	Sleeve								8.20	60%	IW	Int	CL	Hook defect
		0.281			17-07802	27.80		iw	I	nl	Int; weld anomaly;	12.00	40%	IW	Int	CL	Hook defect
												3.00	40%	IW	Int	CL	Hook defect
												4.20	28%	IW	Int	CL	Hook defect
					17-07507	28.40		iw	I	nl	Int; weld anomaly;	29.00	50%	IW	Mid	CL	Hook defect, not quite ID breaking
		0.281										9.70	8%	IW	E	CL	Linear Indication
983.4174	102180	0.281	AO Smith		18-00026	9.50		iw	nd	nl	weld anomaly;	N/A	N/A	N/A	N/A	N/A	Nothing found
984.5432	103650	0.281	AO Smith		18-03631	10.10		iw	I	nl	weld anomaly; slg;	4.53	41%	AW	Int	ML	Metal loss in base metal and at the weld.
987.3705	107560	0.281	AO Smith	Sleeve	S05802	4.53		aw	Int	nd	cl or weld ihg;						
989.8706	111150	0.281	AO Smith	Recoat	T08051	24.61		bm	nd	geo	dent; with ml; possibly with minor cracks;	22.00	2.1%	BM	Ext	Dent	dent
989.9240	111230	0.281	AO Smith	Recoat	T08896	6.79	12.5-25	bm	Int	cl		6.00	15%	BM	Int	Gouge	gouge/ metal loss
996.0569	226	0.281	AO Smith	Recoat	A12566	12.67		aw	Ext	ml	possibly with minor cracks; across Gw;	13.00	12%	AW	Ext	ML	corrosion pitted area along girth weld
996.0601	230	0.281	AO Smith	Recoat	A00460	8.43		bm	Ext	ml	possibly with minor cracks;	12.00	2%		Ext	Mech	Slight OD gouge 0.005" deep
1003.4312	10380	0.281	AO Smith	Sleeve	03-12807	11.60		iw	I	nl	weld anomaly; Int;	4.60	22%	IW	Int	CL	ID Connected Hook defect
												3.00	22%	IW	Int	CL	ID Connected Hook defect
1005.6238	13440	0.281	AO Smith		03-09416	31.00		iw	I	nl	weld anomaly; nGW; Int;	11.20	35%	IW	Int	CL	Linear Indication
		0.281			03-09419	33.50		iw	I	nl	weld anomaly; Int;	7.40	30%	IW	Int	CL	Linear Indication
		0.281			03-09421	2.10		iw	I	nl	weld anomaly; Int;	2.40	29%	IW	Int	CL	Linear Indication
1012.7136	23360	0.281	AO Smith		06-11384	14.20		iw	I	nl	weld anomaly; Int;	15.40	35%	IW	Int	CL	Intermittent Linear Indications
		0.281			06-11386	38.20		iw	I	nl	weld anomaly; Int;	40.20	35%	IW	Int	CL	Intermittent Linear Indications
1013.2106	23990	0.281	AO Smith		06-02369	25.80		aw	nd	nl	weld anomaly;	74.60	10%	AW	Int/Ext	CL	Intermittent Linear Indications (1 @ ID, 1 @ OD)
1010.1931	19750	0.281	AO Smith	Sleeve	E01337	4.06		aw	Ext	nl	weld anomaly;	2.00	<30%	AW	Ext	U	Non fusion weld flaw-non surface breaking
		0.281										5.25	<30%	AW	Ext	U	Non-fusion weld flaw non surface breaking
1010.2005	19770	0.281	AO Smith	Sleeve	E01365	3.27		iw	Int	nl	weld anomaly; slg	3.50	20%	IW	Int	CL	Linear Indication
												2.00	18%	IW	Int	CL	ID Connected in weld
1024.6649	30800	0.281	AO Smith	Sleeve	10-00273	8.70		iw	I	nl	weld anomaly;	8.00	27%	IW	Int	CL	ID Connected in weld
1027.4665	43780	0.281	AO Smith	Recoat	K06201	18.94		bm	N/A	geo	dent; + corrosion;	11.50	1%	BM	N/A	Dent	Dent
1033.7854	52470	0.281	AO Smith		13-03016	5.80		iw	I	nl	weld anomaly;	4.10	7%	AW	Int	CEO	Groove at edge of weld
1045.9944	69520	0.281	AO Smith	Recoat	Q06718	3.66			Int			26.00	2%	AW	Int	Mech	ID gouge or tool mark
		0.281		Recoat	Q06721	5.12		aw	Int	nl	slg; slp;	12.00	7%	AW	Int	Mech	ID gouge or tool mark
1046.0014	69530	0.281	AO Smith	Sleeve	Q06738	2.36		iw	Int	nl	weld anomaly;	2.00	20%	IW	Int	CL	Linear Indication
		0.281			Q06745	3.43		iw	Int	nl	weld anomaly;	1.25	20%	IW	Int	U	Linear Indication
		0.281										1.25	20%	IW	Int	U	Linear Indication
1047.3471	71300	0.281	AO Smith	Recoat	R07658	23.39		bm	N/A	geo	dent; + corrosion;	12.00	N/A	BM	N/A	Dent	Dent
1049.8411	74850	0.281	AO Smith	Sleeve	S02027	3.54		ww	N/A	nd	cl or indication from weld;	4.00	10%	AW	N/A	U	Linear Indication
1050.6663	75890	0.281	AO Smith	Recoat	S07931	18.30		bm	N/A	geo	dent; + corrosion;	12.00	N/A	BM	N/A	Dent	Dent
1052.8668	78890	0.281	AO Smith		20-03602	17.00		iw	I	nl	intermittent; weld anomaly	3.80	14.0%	IW	Mid	CL	Midwall lack of fusion
		0.281			20-03606	27.51		iw	I	nl	weld anomaly;	18.30	25.0%	IW	Mid	CL	Midwall lack of fusion
1055.8367	83060	0.281	AO Smith	Sleeve	21-04282	6.60		iw	I	nl	weld anomaly;	10.58	74.0%	IW	E	CL	Crack in weld
1065.0164	95820	0.281	AO Smith	Recoat	X08075	15.83		bm	N/A	geo	nGW, dent; + corrosion;	12.00	N/A	BM	N/A	Dent	Dent
1065.1314	96070	0.281	AO Smith	Recoat	X08076	13.78		bm	N/A	geo	dent; aGW;	7.00	N/A	BM	N/A	Dent	Dent
1066.8421	96920	0.281	AO Smith	Recoat	X08079	18.27		bm	N/A	geo	dent; + corrosion;	15.00	N/A	BM	N/A	Dent	Dent
												12.00	N/A	BM	N/A	Bulge	bulge
												17.00	N/A	BM	N/A	Bulge	bulge
1073.5613	107580	0.281	AO Smith		27-06029	22.10		iw	I	nl	weld anomaly; Int;	12.40	13.0%	IW	Mid	CL	Midwall lack of fusion
		0.281			27-05451	1.40		iw	i	nl		16.80	10.0%	IW	Mid	CL	Midwall lack of fusion
1073.5987	107810	0.281	AO Smith	Recoat	AA08027	21.54		bm	N/A	geo	dent; + corrosion;	15.00	N/A	BM	N/A	Dent	Dent
												12.00	N/A	BM	N/A	Bulge	bulge

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

Inspection Summary

Central Region Office

Office of Pipeline Safety

To: Region Director JH

Date: 1/30/03

P.A.
From: Phil Archuleta, Staff Engineer

Company Inspected: ENBRIDGE ENERGY, LP

Operator: ENBRIDGE ENERGY, LP

Type of Service: Interstate Liquid

Inter-Regional System:	**System Description**	**Inspection I.D.**
	Team O & M	98263

Dates of Inspection: 6/3/02 - 6/7/02

Location: Duluth, MN

Facilities Inspected: Phil Archuleta, Dave Barrett, Brian Pierzina (MNOPS) and Boyd Haugrose (MNOPS) conducted a Team O & M inspection of Enbridge Energy's procedure manuals. The inspection was conducted using the "**STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER**" inspection form. All documents requested were presented and were satisfactory with the exception of items noted below under "Deficiencies Found."

Persons Interviewed:

Refer to page 1 of the attached "Standard" form for a listing of persons interviewed.

Deficiencies Found:

A review of Enbridge Energy's procedures identified the following deficiencies:

A. Notice of Amendment items:

1. **§195.50 Reporting accidents.**

   An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:

   §195.50(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon

dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:

(1) Not otherwise reportable under this section;
(2) Not one described in Sec. 195.52(a)(4);
(3) Confined to company property or pipeline right-of-way; and
(4) Cleaned up promptly;

The operator's procedure did not include the new 5 gallon reporting requirements for a product release.

2. **§195.54 Accident reports.**

§195.54(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days.

The operator's procedure is inadequate because it restricts the filing of a supplemental report to only when there are changes that the operator considers "significant changes" instead of "any changes" as the regulation requires.

3. **§195.55 Reporting safety-related conditions.**

§195.55(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §195.56 the existence of any of the following safety-related conditions involving pipelines in service:

§195.55(a)(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

The operator's procedure did not include verbiage on general and localized corrosion as a safety related condition.

4. **§195.56 Filing safety-related condition reports.**

§195.56(b) The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.
(2) Date of report.
(3) Name, job title, and business telephone number of person submitting the report.
(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.
(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

The operator's procedure did not specifically include the eight informational elements that must be included in a safety related condition report.

5. **§195.120 Passage of internal inspection devices.**

§195.120(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

The operator's procedure did not include verbiage on making all components piggable.

6. **§195.214 Welding: General.**

§195.214(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

The operator's procedure did not include verbiage about the quality of test welds used to qualify welding procedures shall be determined by destructive testing.

§195.214(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

The operator's procedure did not include verbiage on what welding procedure details and qualification tests results shall be recorded.

7. **§195.234 Welds: Nondestructive testing.**

§195.234(b) Any nondestructive testing of welds must be performed-

(1) In accordance with a written set of procedures for nondestructive testing; and
(2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

The operator's procedure did not include verbiage on specific procedures for non-destructive testing or verbiage about the process of operator approval for contractor non-destructive testing methods.

8. **§195.266 Construction records.**

A complete record that shows the following must be maintained by the operator involved for the life of each pipeline facility:

(a) The total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.
(b) The amount, location, and cover of each size of pipe installed.
(c) The location of each crossing of another pipeline.
(d) The location of each buried utility crossing.
(e) The location of each overhead crossing.
(f) The location of each valve and corrosion test station.

The operator's procedure did not include verbiage about recording the total number of girth welds and the number nondestructively tested, the number rejected and the disposition of each rejected weld.

9. **§195.306 Test medium.**

§195.306(b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if-

(1) The entire pipeline under test is outside of cities and other populated areas;
(2) Each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;
(3) The test section is kept under surveillance by regular patrols during the test; and,
(4) Continuous communication is maintained along entire test section.

The operator's procedure did not include the criteria for using crude oil as a pressure test medium.

10. **§195.308 Testing of tie-ins.**

Pipe associated with tie-ins must be pressure tested, either with the section to be tied

in or separately.

The operator's procedure did not include verbiage on whether tie-in pipe is to be tested with the section to be tied in or is to be tested separately.

11. **§195.310 Records.**

§195.310(b) The record required by paragraph (a) of this section must include:

§195.310(b)(9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

The operator's procedure did not include a requirement for providing a profile whenever there is a 100' elevation difference as part of the pressure test records.

12. **§195.402 Procedural manual for operations, maintenance, and emergencies.**

§195.402(a) General. Each operator shall prepare and follow for each pipeline system a manual ~~of~~ written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

The operator's procedure is inadequate because the operator's O & M manual makes direct reference to various operator Engineering Standards, however the procedure does not require that the Engineering Standards should be reviewed on an annual basis.

§195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

§195.402(c)(1) Making construction records, maps, and operating history available as necessary for safe operation and maintenance.

The operator's procedure did not include verbiage about the minimum distribution requirements for drawings and drawing revisions.

§195.402(c)(5) Analyzing pipeline accidents to determine their causes.

The operator's procedure did not include verbiage on analyzing accidents to determine their causes.

§195.402(c)(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.

The operator's procedure did not include verbiage on minimizing the potential for hazards and minimizing the possibility of recurrence of accidents.

§195.402(c)(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with §195.59 of this part.

The operator's procedure did not include verbiage on filing reports under §195.59.

§195.402(f) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §195.55.

The operator's procedure did not include verbiage about recognition and discovery of safety related conditions.

13. **§195.403 Training.**

§195.403(b) At intervals not exceeding 15 months, but at least once each calendar year, the operator shall:

§195.403(b)(1) Review with personnel their performance in meeting the objectives the training program set forth in paragraph (a) of this section;

The operator's procedure did not include verbiage that for emergency response training there shall be reviews of personnel performance once each calendar year not exceeding 15 months.

§195.403(b)(2) Make appropriate changes to the training program as necessary to ensure that it is effective.

The operator's procedure did not include verbiage about making appropriate changes to emergency response training as needed to insure that the training is effective.

§195.403(c) Each operator shall require and verify that its supervisors maintain a

thorough knowledge of that portion of the procedures established under 195.402 for which they are responsible to insure [sic] compliance.

The operator's procedure did not include verbiage about how supervisors maintain knowledge of the emergency response procedures for which supervisors are responsible.

14. **§195.404 Maps and Records.**

§195.404(b) Each operator shall maintain for at least 3 years daily operating records that indicate-

§195.404(b)(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

The operator's procedure is inadequate because Table 3 of the operator's "Pipeline Operations Records" has not been revised to include abnormal operation records that are recorded using "FACMAN" software.

15. **§195.410 Line markers.**

§195.410(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

§195.410(a)(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

The operator's procedure did not include verbiage on what other line marker locations are sufficient to accurately locate the line.

§195.410(c) Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public.

The operator's procedure did not include verbiage about line markers in aboveground areas accessible to the public.

16. **§195.412 Inspection of rights-of-way and crossings under navigable waters.**

§195.412(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate mean of traversing the right-of-way.

The operator's procedure is inadequate because it restricts follow up on items found during right-of-way inspections to only items that the operator considers "significant" and it does not make clear that follow up action, if needed, must be for all items requiring inspection under the regulations and not just what the operator considers "significant".

§195.412(b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.

The operator's procedure did not include verbiage on what specific crossing components are to be inspected during a waterway inspection.

17. **§195.420 Valve maintenance.**

§195.420(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

The operator's procedure did not include verbiage about maintaining all valves necessary for the safe operation of the operator's pipeline system.

18. **§195.422 Pipeline repairs.**

§195.422(b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

The operator's procedure did not include an overview statement that replacement components shall be design and maximum operating pressure compatible with existing facilities and the operator's procedure did not reference company Engineering Standards.

19. **§195.428 Overpressure safety devices.**

§195.428(d) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

The operator's procedure is inadequate because the tank internal inspection table included in the O & M manual did not include the testing of overfill protection systems on breakout tanks, including the NGL breakout tanks.

20. **§195.555 What are the qualifications for supervisors?**

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under Sec. 195.402(c)(3) for which they are responsible for insuring compliance.

The operator's procedure did not include verbiage that corrosion control supervisors must maintain knowledge of that portion of the corrosion control procedures for which the supervisors are responsible.

21. **§195.569 Do I have to examine exposed portions of buried pipelines?**

    Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

    The operator's procedure did not include verbiage about examining all exposed pipe whenever the operator has knowledge of exposed pipe.

22. **§195.573 What must I do to monitor external corrosion control?**

    §195.573(a) Proteeted pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:

    §195.573(a)(2) Identify before December 29, 2003 or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP0169-96 (incorporated by reference, see Sec. 195.3).

    The operator's procedure did not include verbiage on the criteria for a close interval survey and when a close interval survey is required.

    §195.573(e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

    The operator's procedure did not include verbiage on the criteria if a deficiency involves a pipeline under an integrity management program and verbiage on what the intervals are for completing repairs on deficiencies.

23. **§195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**

    §195.575(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically

protect the pipeline and the other structures as a single unit.

§195.575(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

§195.575(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

§195.575(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.

§195.575(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

The operator's procedure did not include verbiage on what facilities require electrical isolation and what inspections, tests and additional safeguards are required.

24. **§195.577 What must I do to alleviate interference currents?**

§195.577(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.

§195.577(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

The operator's procedure did not include verbiage about designing and installing cathodic protection systems to minimize effects on existing adjacent metallic structures.

25. **§195.579 What must I do to mitigate internal corrosion?**

§195.579(c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

The operator's procedure did not include verbiage about checking adjacent pipe when internal corrosion is found.

26. **§195.589 What corrosion control information do I have to maintain?**

§195.589(a) You must maintain current records or maps to show the location of--

> **(1) Cathodically protected pipelines;**
> **(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and**
> **(3) Neighboring structures bonded to cathodic protection systems.**

§195.589(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

§195.589(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

(1) The operator's procedure did not include verbiage on the criteria for records retention periods for corrosion control information.

(2) The operator's procedure did not include verbiage about documenting all inspections performed under §195.583, even when no corrective action is needed.

Conclusions/Recommendations:

It is recommended that Enbridge Energy be issued a Notice of Amendment for all items listed under paragraph A.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator: ENBRIDGE ENERGY, LP

H.Q. Address:	**System/Unit Name and Address:**
SUITE 2950 1100 LOUISIANA HOUSTON, TX 77002	
Co. Official: Mr. Dan Tutcher, President	**Phone No.:**
Phone No.: 713-650-8900	**Fax No.:**
Fax No.: 713-653-6711	**Emergency Phone No.:**
Emergency Phone No.: 800-858-5253	**Unit Record ID#:**
OPINS ID#: #11169	**Activity Record ID#:** #98263

Persons Interviewed	Titles	Phone No.
Refer to attached copy of		
attendance sheet.		

OPS Representative(s): Phil Archuletta, Dave Barrett, Boyd Haugrose (MNOPS), Brian Pierzina (MNOPS)

Date(s): 6/3 - 6/7/2002

Company System Maps (copies for Region Files):

Comments:

For hazardous liquid operator inspections, the attached evaluation form should be used in conjunction with 49 CFR 195 during OPS inspections.

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description: ENBRIDGE US TEAM O&M and TEAM OQ INSPECTION

Date: JUNE 4, 2002

Location: DULUTH, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	General Engineer	DOT-RSPA-OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	John Sobojinski	Manager-Compliance & Risk Management	Enbridge (US)	218 725-0505	John.Sobojinski@Enbridge-US.com
3	LYNNE HARRINGTON	TRAINING COORDINATOR	ENBRIDGE US	(218) 725-0119	LYNNE.HARRINGTON@ENBRIDGE-US.COM
4	Todd Gilseth	Safety Analyst	Enbridge-US	218 259-6605	Todd.Gilseth@enbridge-us.com
5	Janet Hoggett	documentation Mgt coord.	Enbridge Pipelines	780 420 5142	janet.hoggett@cnpl.enbridge.com
6	Patty Bolk	secretary	Enbridge	218 725-0105	patty.bolk@enbridge-us.com
7	DAVID MCNEILL	SUPERVISOR PIPELINE INTEGRITY PROGRAMS	ENBRIDGE	780 420-8731	dave.mcneill@cnpl.enbridge.com
8	JAY A. JOHNSON	COMPLIANCE & RISK MANAGEMENT COORD.	ENBRIDGE	218/725-0512	jay.johnson@enbridge-us.com
9	BOYD HAUGROSE	INSPECTOR	MNOPS	218 923 3608	boyd.haugrose@state.mn.us
10	Brian Pierzina	SR. ENGINEER	MNOPS	218-327-4218	brian.pierzina@state.mn.us
11	Dave Barrett	Engineer	DOT/OPS	816-329-3817	david.barrett@rspa.dot.gov
12	Carl Griffis	Engineer	DOT/OPS	219-601-8586	carl.griffis@rspa.dot.gov
13	GAIL FOLLIS	ENGINEERING DESIGNER	ENBRIDGE-US	218-725-0536	GAIL.FOLLIS@ENBRIDGE-US.COM
14	DEAN CARPENTER	"	"	0525	

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
15	DEAN RAWSON	CONT CENTER ENGINEER	ENBRIDGE CAN.	780/420 ~~5267~~ 5285	
16	SCOTT IRONSIDE	PIPELINE INT. ENGINEER	" "	780/420-5267	
17	KARL BLANK	OPS. SERVICES ENGINEER -TANKS	" "	780/420-8189	
18	RICK AUNET	SUPERIOR TERM. SUPERVISOR	ENB. U.S.		
19	KIMBERLY HARRIS	SENIOR CATHODIC TECHNICIAN	ENB. U.S.	219/765-9272	
20					
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STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

HVL PIPELINE TESTING SUMMARY	N/A	Yes	No
1. Do the operator's pipelines transport HVLs?		✔	
2. Has the operator pressure tested the following "older" HVL pipelines per subpart E; or, for pipelines that have not been converted under 195.5, has the operator established these pipelines' MOP's per 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure]? **The pressure test and MOP establishment (195.406(a)(5)) deadlines for the below listed lines have passed.**	✔		
a. Onshore non low stress Interstate Lines in HVL service prior to 9/8/80 and constructed prior to 1/8/71.	✔		
b. Onshore non low stress Intrastate Lines in HVL service prior to 4/23/85 and constructed prior to 10/21/85.	✔		
c. Low stress lines in HVL service that existed on 7/12/94, or ones that were constructed before 8/11/94.	✔		

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

PIPELINE INFORMATION

Boundaries of Unit:

Pipelines and Pumping Stations in Unit:

Designation	*Size*	*Miles*	*Commodities*

Miles of Pipeline:	**Protected**	**Size**	**Size**	**Size**	**Unprotected**	**Size**	**Size**	**Size**
Steel Bare								
Steel Coated								
Other								

Breakout Tank Facilities:

Offshore Facilities:

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

	Conversion to Service	S	U	N/A	N/C
§195.5	Has a written procedure been developed addressing all applicable requirements and followed?			✔	

Comments *(If the above is Unsatisfactory, please indicate why):*

	Subpart B - Reporting of Accidents & Safety Related Conditions	S	U	N/A	N/C
§195.402(c)(2)	Does the operator have procedures for gathering data needed for reporting accidents under **Subpart B** of this part in a timely and effective manner?		✔		
§195.50	Does the operator file accident reports as required under 195.50? Under certain conditions, a release of more than 5 gals, or more is reported.		✔		
§195.52	Are certain incidents telephonically reported to the **National Response Center**?	✔			
§195.54	Are the incidents reported by telephone followed up with a 30-day written report?		✔		
§195.402(f)	Does the operator have procedures for recognizing and discovery of safety-related conditions?		✔		
§195.55	If the operator reported a safety-related condition, did they use the proper criteria?		✔		
§195.56	Is there a procedure for reporting safety-related conditions?	✔			
§195.56(a)	Was the report filed within five (5) working days of the determination and within ten (10) working days after discovery?	✔			
§195.56(b)	Was proper corrective action taken?		✔		
§195.59	Does the operator file abandoned underwater facility reports.	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(c)(2) The operator's procedure is unsatisfactory because procedures for some of the elements under Subpart B were unsatisfactory.

§195.50 The operator's procedure did not include the new 5 gallon reporting requirements for a product release.

§195.54 The operator's procedure is inadequate because it restricts the filing of a supplemental report to only when there are changes that the operator considers "significant changes" instead of "any changes" as the regulation requires.

§195.402(f) The operator's procedure did not include adequate verbiage about recognition and discovery of safety related conditions.

§195.55 The operator's procedure did not include verbiage on general and localized corrosion as a safety related condition.

§195.56(b) The operator's procedure did not specifically include the eight informational elements that must be included in a safety related condition report.

	Subpart C - Passage of Internal Inspection Devices	S	U	N/A	N/C
§195.120(a)	Has each new pipeline or each section of a pipeline which pipe or components has been replaced been designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section?		✔		

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.120(a) The operator's procedure did not include verbiage on making all components piggable. The operator's O & M manual did not make a specific reference to company Engineering Standards.

	Subpart D - Welding	S	U	N/A	N/C
	Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is require by §195.422, as well as §195.200.				
§195.214(a)	Is the welding performed in accordance with welding procedures qualified to produce welds meeting the requirements of this **Subpart**?	✔			
	Has the quality of the test welds to qualify the procedures been determined by destructive testing?		✔		
§195.214(b)	Is each welding procedure recorded in detail?	✔			
	Are welding procedures qualified in accordance with a standard that is accepted by the industry? **(API 1104, ASME Boiler & Pressure Code - Section IX, or other)**	✔			
	Are detailed results of the **procedure qualification tests**, recorded and retained?		✔		
§195.222	Is welding performed by welders, who have been qualified in accordance with **Section 3 of the API Standard 1104 (18th Ed., 1994)** or **Section IX of the ASME Boiler and Pressure Vessel Code (1995)**, except that a welder qualified under an earlier edition than listed in **§195.3** may weld, but may not requalify under that earlier edition?	✔			
Alert Notice 3/13/88	**In the welding of repair sleeves and fittings, does the operator's procedures give consideration to:**				
	1. The use of low hydrogen welding rods.	✔			
	2. Cooling rate of the weld.	✔			
	3. Metallurgy of the materials being welded (weldability carbon equivalent).	✔			
	4. Proper support of the pipe in the ditch.	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.214(a) The operator's procedure did not include verbiage about the quality of test welds used to qualify welding procedures shall be determined by destructive testing.

§195.214(b) The operator's procedure did not include verbiage on what welding procedure details and qualification tests results shall be recorded. Additionally, some Welding Procedure Specifications did not reference corresponding Procedure Qualification Records.

	Welding: Arc Burns	S	U	N/A	N/C
§195.226(a)	Does the operator require the repair (within pipe and (b) specification thickness tolerances) or replacement of arc burns?	✔			
§195.226(b)	Does the operator require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**	✔			
§195.226(c)	When pipe is being welded, is the ground wire attached to the pipe by other means than welding?	✔			

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Welds: Acceptability - Nondestructive Testing	S	U	N/A	N/C
§195.228	Does the operator nondestructively test welds to insure their acceptability according to **Section 6 of API 1104 (18th)** and per the requirements of **§195.234** in regard to the number of welds to be tested?	✔			
§195.234(b)	Is nondestructive testing of welds performed:				
	1. In accordance with written procedures for NDT.		✔		
	2. By qualified personnel.	✔			
	3. By a process that will indicate any defects that may affect the integrity of the weld.	✔			
§195.266	Does the operator maintain records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld?		✔		

Comments *(If any of the above is Unsatisfactory, please indicate why):* §195.234(b) The operator's procedure did not include verbiage on specific procedures for non-destructive testing or verbiage about the process of operator approval for contractor non-destructive testing methods. §195.266 The operator's procedure did not include verbiage about recording the total number of girth welds and the number nondestructively tested, the number rejected and the disposition of each rejected weld.

	Welds: Repair or Removal of Defects	S	U	N/A	N/C
§195.230	Does the operator remove and/or repair welds that are unacceptable in accordance with the requirements of **§195.230**?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Subpart E - Pressure Testing	S	U	N/A	N/C
§195.302(a)	Does the operator pressure test each new pipeline system and each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced?	✔			
	Are lines that have not been pressure tested per subpart E being operated in accordance with this subsection?			✔	
§195.302(c)	Have/are the below listed pipelines (excluding converted lines and lines covered under the risk assessment option in §195. 303) being pressure tested per subpart E; or, was the MOP established prior to 12/7/98, using the prescribed pressure in 195.406(a)(5) [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] ?	✔			
	- Interstate liquid lines constructed before 01/08/71 (excluding HVL onshore or low stress lines).	✔			

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		S	U	N/A	N/C
	- Interstate liquid offshore gathering lines constructed before 08-01-77 (excluding low stress lines).			✔	
	- Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines).			✔	
	- Carbon dioxide lines constructed before 07/12/91 (excluding rural production field distribution or low stress lines).			✔	
§195.303	Does the operator comply with the risk based alternative to pressure testing?			✔	
§195.304	The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure.	✔			

Subpart E - Pressure Testing (Con't)		S	U	N/A	N/C
§195.305(a)	Does the operator pressure test under **§195.302** all pipe, all attached fittings, including components?	✔			
§195.305(b)	A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.	✔			
§195.306	Is the appropriate test medium used?		✔		
§195.308	Does the operator pressure test pipe associated with tie-ins as one segment or tested separately?		✔		
§195.310(a)	Does the operator maintain a record of each pressure test required by this **Subpart**?	✔			
§195.310(b)	Does the record required by paragraph **(a)** of this section include:				
§195.310(b)(1)	Pressure recording charts.	✔			
§195.310(b)(2)	Test instrument calibration data.	✔			
§195.310(b)(3)	Name of the operator, person responsible, test company used, if any.	✔			
§195.310(b)(4)	Date and time of the test.	✔			
§195.310(b)(5)	Minimum test pressure.	✔			
§195.310(b)(6)	Test medium.	✔			
§195.310(b)(7)	Description of the facility tested and the test apparatus.	✔			
§195.310(b)(8)	Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.	✔			
§195.310(b)(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included.		✔		

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

§195.306 The operator's procedure did not include the criteria for using crude oil as a pressure test medium.

§195.308 The operator's procedure did not include verbiage on whether tie-in pipe is to be tested with the section to be tied in or is to be tested separately.

§195.310(b)(9) The operator's procedure did not include a requirement for providing a profile whenever there is a 100' elevation difference as part of the pressure test records.

Subpart F - Operations & Maintenance		S	U	N/A	N/C
§195.401(b)	Has the operator corrected conditions that could adversely affect the safe operation of the pipeline within a reasonable time?				✔
§195.402(a)	a. Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies?				✔
	b. Does the operator review the manual at intervals not exceeding 15 months, but at least each calendar year?		✔		

		S	U	N/A	N/C
	c. Are the manuals available, as required?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is inadequate because the operator's O & M manual makes direct reference to various operator Engineering Standards, however the procedure does not require that the Engineering Standards should be reviewed on a annual basis.

	Maintenance & Normal Operations	S	U	N/A	N/C
§195.402(c)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for:				
§195.402(c)(4)	Has the operator determined which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned?	✔			
§195.402(c)(5)	Analyzing pipeline accidents to determine their causes?		✔		
§195.402(c)(6)	Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**?		✔		
§195.402(c)(7)	Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices?	✔			
§195.402(c)(8)	In the case of a pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**?	✔			
§195.402(c)(9)	In the case of facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location?	✔			
§195.402(c)(10)	Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards; filing Reports per 195.59 upon abandoning underwater facilities crossing navigable waterways, including off-shore facilities?		✔		
§195.402(c)(11)	Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases?	✔			
§195.402(c)(12)	Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency.	✔			
§195.402(c)(13)	Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found?	✔			
§195.402(c)(14)	Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.	✔			

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(c)(5) The operator's procedure did not include verbiage on analyzing accidents to determine their causes.

§195.402(c)(6) The operator's procedure did not include verbiage on minimizing the potential for hazards and minimizing the possibility of recurrence of accidents.

§195.402(c)(10) The operator's procedure did not include verbiage on filing reports under §195.59.

Abnormal Operation (Control Center Function)		S	U	N/A	N/C
§195.402(d)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for:				
§195.402(d)(1)	Responding to, investigating, and correcting the cause of:				
	i. Unintended closure of valves or shutdowns?	✔			
	ii. An increase or decrease or flow rate outside normal operating limits?	✔			
	iii. Loss of communications?	✔			
	iv. The operation of any safety device?	✔			
	v.. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?	✔			
§195.402(d)(2)	Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations?	✔			
§195.402(d)(3)	Correcting variations from normal operation of pressure and flow equipment controls?	✔			
§195.402(d)(4)	Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received?	✔			
§195.402(d)(5)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found?				✔

Comments *(If any of the above is Unsatisfactory, please indicate why):*
§195.402(d)(5) This was not checked because it was a compliance issue from a 2001 inspection for which the operator submitted revised procedures. The revised procedures had not been reviewed at the time of this 2002 Team O & M inspection. The revised procedures have now been reviewed and were found to be acceptable.

Emergencies		S	U	N/A	N/C
§195.402(e)	The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for:				
§195.402(e)(1)	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action?				✔
§195.402(e)(2)	Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline?	✔			
§195.402(e)(3)	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency?	✔			

		S	U	N/A	N/C
§195.402(e)(4)	Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site?	✔			
§195.402(e)(5)	Controlling the release of liquid at the failure site?	✔			
§195.402(e)(6)	Minimizing the public exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?	✔			
§195.402(e)(7)	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including HVLs?	✔			
§195.402(e)(8)	Determining extent and coverage of vapor cloud and hazardous areas of HVLs by using appropriate instruments?	✔			
§195.402(e)(9)	Post accident review of employees activities to determine if procedures were effective and corrective action was taken?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(e)(1) This was not checked because it was a compliance issue from a 2001 inspection for which the operator submitted revised procedures. The revised procedures had not been reviewed at the time of this 2002 Team O & M inspection. The revised procedures have now been reviewed and were found to be acceptable.

	Training (Control Center & Field)	S	U	N/A	N/C
§195.403(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel too:				
§195.403(a)(1)	Carry out the operating and maintenance, and emergency response procedures established under §195.402.	✔			
§195.403(a)(2)	Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of HVL, flammability, of mixtures with air, odorless vapors, and water reactions.	✔			
§195.403(a)(3)	Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions.	✔			
§195.403(a)(4)	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage.	✔			
§195.403(a)(5)	Learn the proper use of fire fighting procedures and equipment, fire suits, and breathing apparatus, etc.	✔			
§195.403(a)(6)	Safely repair facilities, special precautions, isolation, purging of HVLs.	✔			
§195.402(f)	Recognize and report safety related conditions.		✔		
§195.403(b)	At intervals not exceeding 15 months, but at least once each calender year:				
§195.403(b)(1)	Does the operator review with personnel their performance in meeting the objectives of the training program?		✔		
§195.403(b)(2)	Does the operator make appropriate changes to the training program?		✔		
§195.403(c)	Does the operator require and verify, its supervisors maintain a thorough knowledge of the procedures they are responsible for?		✔		

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why)*:

§195.402(f) The operator's procedure did not include verbiage about recognition and discovery of safety related conditions.

§195.403(b)(1) The operator's procedure did not include verbiage that for emergency response training there shall be reviews of personnel performance once each calendar year not exceeding 15 months.

§195.403(b)(2) The operator's procedure did not include verbiage about making appropriate changes to emergency response training as needed to insure that the training is effective.

§195.403(c) The operator's procedure did not include verbiage about how supervisors maintain knowledge of the emergency response procedures for which supervisors are responsible.

	Maps and Records	S	U	N/A	N/C
§195.402(a)	Are there procedures for maintaining current maps and records?		✔		
§195.404(a)	Each operator shall maintain current maps and records of its pipeline system that include at least the following information:				
§195.404(a)(1)	Location and identification of the following facilities:				
	i. Breakout tanks	✔			
	ii. Pump stations	✔			
	iii. Scraper and sphere facilities	✔			
	iv. Pipeline valves	✔			
	v. Facilities to which **§195.402(c)(9)** applies	✔			
	vi. Rights-of-way	✔			
	vii. Safety devices to which **§195.428** applies	✔			
§195.404(a)(2)	All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines.	✔			
§195.404(a)(3)	The maximum operating pressure of each pipeline.	✔			
§195.404(a)(4)	The diameter, grade, type, and nominal wall thickness of all pipe.	✔			
§195.404(b)	Each operator shall maintain for at least **3 years** daily operating records for the following:				
§195.404(b)(1)	The discharge pressure at each pump station.	✔			
§195.404(b)(2)	Any emergency or abnormal operation to which the procedures under **§195.402** apply.		✔		
§195.404(c)	Each operator shall maintain the following records for the periods specified:				
§195.404(c)(1)	The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**.	✔			
§195.404(c)(2)	The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**.	✔			
§195.404(c)(3)	Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**.	✔			
§195.402(c)(1)	Making construction records, maps, and operating history available as necessary for safe operation and maintenance.		✔		

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is unsatisfactory because procedures for some of the elements under §195.402(c)(1) and §195.404(b)(2) were unsatisfactory.

§195.404(b)(2) The operator's procedure is inadequate because Table 3 of the operator's "Pipeline Operations Records" has not been revised to include abnormal operation records that are recorded using "FACMAN" software.

§195.402(c)(1) The operator's procedure did not include verbiage about the minimum distribution requirements for drawings and drawing revisions.

	Maximum Operating Pressure (MOP) - All Systems	S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.406**?	✔			
§195.406(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following:				
§195.406(a)(1)	The internal design pressure of the pipe determined by **§195.106**.	✔			
§195.406(a)(2)	The design pressure of any other component on the pipeline.	✔			
§195.406(a)(3)	**80%** of the test pressure **(Subpart E)**.	✔			
§195.406(a)(4)	**80%** of the factory test pressure or of the prototype test pressure for any individual component.	✔			
§195.406(a)(5)	**80%** of the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**.			✔	
§195.406(b)	The pipeline may not be operated at a pressure that exceed **110% of the MOP**:				
	a. Has the operating pressure exceeded the **MOP** by more than **110%**?				✔
	b. Are adequate controls and protective equipment installed to prevent the pressure from exceeding **110%** of the **MOP**?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.406(b) a. This was not checked because the team considered this to be a records review item.

	Communications (Control Center)	S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.408**?	✔			
§195.408(a)	Does the operator have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system?	✔			
§195.408(b)	Does the communication system required by paragraph **(a)** include means for:				
§195.408(b)(1)	Monitoring operational data as required by **§195.402(c)(9)**.	✔			
§195.408(b)(2)	Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions.	✔			

		S	U	N/A	N/C
§195.408(b)(3)	Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies.	✔			
§195.408(b)(4)	Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Line Markers		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.410**?		✔		
§195.410(a)	Each operator shall place and maintain line markers over each buried pipeline in accordance with the following:				
§195.410(a)(1)	Are line markers placed at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known?		✔		
§195.410(a)(2)	Do the line markers have the correct characteristics and information?	✔			
§195.410(b)	Line markers are not required for buried pipelines located:				
§195.410(b)(1)	Offshore or at crossings of or under waterways and other bodies of water.			✔	
§195.410(b)(2)	In heavily developed urban areas such as downtown business centers where (1) placement is impracticable and (2) the local government maintains current substructure records.			✔	
§195.410(c)	Are line markers placed where pipelines are aboveground in areas that are accessible to the public?		✔		

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is unsatisfactory because procedures for some of the elements under §195.410(a)(1) and §195.410(c) were unsatisfactory.

§195.410(a)(1) The operator's procedure did not include verbiage on what other line marker locations are sufficient to accurately locate the line.

§195.410(c) The operator's procedure did not include verbiage about line markers in aboveground areas accessible to the public.

Inspection of Rights-of-Way & Crossings Under Navigable Waters		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.412**?		✔		
§195.412(a)	Does the operator inspect the right-of-way at intervals not exceeding **3 weeks**, but at least **26 times each calendar year**?	✔			
	Does the operator follow-up on problems noted by the patrol?		✔		
§195.412(b)	Does the operator inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding **5 years**?		✔		
§195.402(a)	Are there procedures for **§195.413**?			✔	

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is unsatisfactory because procedures for some of the elements under §195.412(a) and §195.412(b) were unsatisfactory.

§195.412(a) The operator's procedure is inadequate because it restricts follow up on items found during right-of-way inspections to only items that the operator considers "significant" and it does not make clear that follow up action, if needed, must be for all items requiring inspection under the regulations and not just what the operator considers "significant".

§195.412(b) The operator's procedure did not include verbiage on what specific crossing components are to be inspected during a waterway inspection.

	Underwater Inspections of Offshore Pipelines	S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.413**?			✔	
§195.413(a)	Has the operator conducted an underwater inspection of its pipelines in the **Gulf of Mexico** and its inlets between **October 3, 1989** and **November 16,1992**?			✔	
§195.413(b)	When the operator discovers a pipeline, it operates, is exposed on the seabed or constitutes a hazard to navigation does the operator:				
§195.413(b)(2)	Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline segment less than **200 yards long** need only be marked at the center.			✔	
§195.413(b)(3)	Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, place the pipeline so that the top of the pipe is **36 inches** below the seabed for normal excavation or **18 inches** for rock			✔	
§195.57	Has the operator **filed** a report within **60 days** of the inspection as required by **§195.413**?			✔	

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Valve Maintenance	S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.420**?		✔		
§195.420(a)	Does the operator maintain each mainline valve that is necessary for the safe operation of its pipeline system in good working order at all times?		✔		
§195.420(b)	Does the operator inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **7½ months**, but at least **twice** each calendar year?				✔
§195.420(c)	Does the operator provide protection for each valve from unauthorized operation and from vandalism?	✔			

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is unsatisfactory because procedures for some of the elements under §195.420(a) were unsatisfactory.

§195.420(a) The operator's procedure did not include verbiage about maintaining all valves necessary for the safe operation of the operator's pipeline system.

Pipeline Repairs		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.422**?		✔		
§195.422(a)	Does the operator, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property?	✔			
§195.422(b)	No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.		✔		

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is unsatisfactory because procedures for some of the elements under §195.422(b) were unsatisfactory.

§195.422(b) The operator's procedure did not include an overview statement that replacement components shall be design and maximum operating pressure compatible with existing facilities. The operator's O & M procedures also did not make reference to company Engineering Standards followed for replacement of pipe, valves and other components.

Pipe Movement		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.424**?	✔			
§195.424(a)	When moving any pipeline, does the operator reduce the pressure for the line segment involved to **50% of the MOP**.	✔			
§195.424(b)	For **HVL** lines **joined** by welding, does the operator:				
§195.424(b)(1)	Move the line when it does not contain **HVL**, unless impractical.	✔			
§195.424(b)(2)	Have procedures under **§195.402** containing precautions to protect the public.			✔	
§195.424(b)(3)	Reduce the pressure for the line segment involved to **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig)**			✔	
§195.424(c)	For **HVL** lines **not joined** by welding, does the operator:				
§195.424(c)(1)	Move the line when it does not contain **HVL**, unless impractical.			✔	
§195.424(c)(2)	Have procedures under **§195.402** containing precautions to protect the public.			✔	
§195.424(c)(3)	Isolate the line to prevent flow of the **HVL**.			✔	

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Scraper and Sphere Facilities	S	U	N/A	N/C
§195.402(a)	Are there procedures for §195.426?	✔			
§195.426	Does the operator, have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres?	✔			
	Does the operator have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Overpressure Safety Devices	S	U	N/A	N/C
§195.402(a)	Are there procedures for §195.428?		✔		
§195.428(a)	Does the operator inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable?	✔			
	Does the operator inspect and test overpressure safety devices at the following intervals:				
	1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.	✔			
	2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.	✔			
§195.428(b)	Does the operator inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**?	✔			
§195.428(c)	Do aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to the appropriate API. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank.	✔			
§195.428(d)	After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.		✔		

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.402(a) The operator's procedure is unsatisfactory because procedures for some of the elements under §195.428(d) were unsatisfactory.

§195.428(d) The operator's procedure is inadequate because the tank internal inspection table included in the O & M manual did not include the testing of overfill protection systems on breakout tanks, including the NGL breakout tanks.

	Firefighting Equipment	S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.430**?	✔			
§195.430	Does the operator maintain adequate firefighting equipment at each pump station and breakout tank areas?	✔			
§195.430	The equipment must be:				
	a.. In proper operating condition at all times.	✔			
	b. Plainly marked so that its identity as firefighting equipment is clear.	✔			
	c. Located so that it is easily accessible during a fire.	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Breakout Tanks	S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.432**?	✔			
§195.432(a)	Inspection of in-service breakout tanks. (annually/ 15mo) includes anhydrous ammonia and any other breakout tank that is not inspected per 432 (b) & (c);	✔			
§195.432(b)	Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).	✔			
§195.432(c)	Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.	✔			
§195.432(d)	The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.	✔			
	Note: For Break-out tank unit inspection, refer to Breakout Tank Form			✔	

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Signs		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.434**?	✔			
§195.434	Does the operator maintain signs visible to the public around each pumping station and breakout tank area?	✔			
	Do the signs contain the name of the operator and an emergency telephone number?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Security of Facilities		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.436**?	✔			
§195.436	Does the operator provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

Smoking or Open Flames		S	U	N/A	N/C
§195.402(a)	Are there procedures for **§195.438**?	✔			
§195.438	Does the operator prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors?	✔			

Comments *(Ifany of the above is Unsatisfactory, please indicate why):*

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

	Public Education	S	U	N/A	N/C
§195.402(a)	Are there procedures for §195.440?	✔			
§195.440	Has the operator established a continuing educational program to enable the public, government, persons engaged in excavation to recognize a hazardous liquid or carbon dioxide pipeline emergency and report it to the operator, fire, police, and others?	✔			
	Is the program conducted in English and other languages where appropriate?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	Damage Prevention Program	S	U	N/A	N/C
§195.442(a)	Does the operator have a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?	✔			
§195.442(b)	Does the operator participate in a qualified One-Call program?	✔			
§195.442(c)(1)	Include the identity, on current a basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.	✔			
§195.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph (c)(1) of this section of the following, as often as needed to make them aware of the damage prevention program:				
	i. The program's existence and purpose.	✔			
	ii. How to learn the location of underground pipelines before excavation activities are begun.	✔			
§195.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.	✔			
§195.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.	✔			
§195.442(c)(5)	Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.	✔			
§195.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
	i. The inspection must be done as frequency as necessary during and after the activities to verify the integrity of the pipeline.	✔			
	ii. In the case of blasting, any inspection must include leakage surveys.	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory U - Unsatisfactory N/A - Not Applicable N/C - Not Checked

	CPM/Leak Detection	S	U	N/A	N/C
§195.444	If a CPM system is installed, does the operator's procedures for the Computational Pipeline Monitoring (CPM) leak detection system comply with API 1130 in operating, maintaining, testing, record keeping, and dispatching training?	✔			

Comments *(If any of the above is Unsatisfactory, please indicate why):*

	High Consequence Areas & Pipeline IMP	S	U	N/A	N/C
§195.450 & §195.452	These sections are currently being developed by OPS IMP group.				✔

	Subpart G - Operator Qualification	S	U	N/A	N/C
§195.501-509	Refer to Operator Qualification - Liquid Form		✔		

	Subpart H - Corrosion Control	S	U	N/A	N/C
§195.555	Does the Operator require and verify that supervisors maintain a through knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance.		✔		
§195.557	Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is :	✔			
	a) constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under 195.424	✔			
	b) Converted under 195.5 and 1) Has an external coating that substantially meets 195.559 before the pipeline is placed in service or;			✔	
	2) Is a segment that is relocated, replaced, or substantially altered.			✔	
§195.559	**Coating Materials;** Coating material for external corrosion control must; a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.	✔			
§195.561	a. All external pipe coatings required under 195.557 must be inspected just prior to lowering the pipe in the ditch or submerging the pipe.	✔			
	b. All coating damage discovered must be repaired.	✔			
§195.563	a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in 195.557(a) within one (1) year?	✔			

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		S	U	N/A	N/C
	b. Each buried or submerged pipeline converted under 195.5 must have cathodic protection if the pipeline-			✔	
	1. Has cathodic protection that substantially meets 195.571 before the pipeline is placed in service, or			✔	
	2. Is a segment that is relocated, replaced, or substantially altered.			✔	
	c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.	✔			

	Subpart H - Corrosion Control (Con't)	**S**	**U**	**N/A**	**N/C**
	d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections.	✔			
	e. Unprotected pipe must have cathodic protection if required by 195.573(b).			✔	
§195.567	Test leads installation and maintenance	✔			
§195.569	Examination of Exposed Portions of Buried Pipelines		✔		
§195.571	Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP0169-96 (incorporated by reference)	✔			
§195.573	a. Pipe to soil monitoring (annually / 15months)	✔			
	Separately protected short sections of bare ineffectively coated pipelines (every 3 years not to exceed 39 months)			✔	
	b. Before 12/29/2003 or not more than 2 years after cathodic protection installed, whichever comes later, identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE RP0169-96.		✔		
	c. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
	1) Determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment.			✔	
	2) Before 12/29/2003 - at least once every 5 years not to exceed 63 months.			✔	
	Beginning 12/29/2003 - at least once every 3 years not to exceed 39 months.			✔	
	d. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - at least 6 times each year, intervals not to exceed 2 ½ months.	✔			
	e. Any deficiencies identified in corrosion control must be corrected as required by 195.401(b).		✔		
§195.575	Are there adequate provisions for electrical isolations?		✔		
§195.577	a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects?	✔			
	b. Design & install CP systems to minimize effects on adjacent metallic structures.		✔		
§195.579	a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken?	✔			
	b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion	✔			
	Coupons or other monitoring equipment must be examined at least 2 times each year, not to exceed 7 ½ months.	✔			
	c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe? What steps are taken to minimize internal corrosion.		✔		

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

		S	U	N/A	N/C
§195.581	Are pipelines protected against Atmospheric Corrosion using required coating material. (See exception to this statement)	✔			
§195.583	Atmospheric corrosion monitoring -				
	ONSHORE - At least once every 3 years but at intervals not exceeding 39 months.		✔		
	OFFSHORE - At least once each year, but at intervals not exceeding 15 months.			✔	

	Subpart H - Corrosion Control (Con't)	**S**	**U**	**N/A**	**N/C**
§195.585	a. Are Procedures in place and are they followed to either reduce the MOP, or repair/replace pipe if general corrosion has reduced the wall thickness?	✔			
	b. Are Procedures in place and are they followed to either reduce the MOP, or repair/replace if localized corrosion has reduced the wall thickness?	✔			
§195.587	Are applicable methods used in determining the strength of corroded pipe (ASME B-31G, RSTRENG)	✔			
§195.589	Corrosion Control Records Retention(Some are required for 5 yrs; Some are for the service life)		✔		

Comments *(If any of the above is Unsatisfactory, please indicate why):*

§195.555 The operator's procedure did not include verbiage that corrosion control supervisors must maintain knowledge of that portion of the corrosion control procedures for which the supervisors are responsible.

§195.569 The operator's procedure did not include verbiage about examining all exposed pipe whenever the operator has knowledge of exposed pipe.

§195.573(a)(2) b. The operator's procedure did not include verbiage on the criteria for a close interval survey and when a close interval survey is required.

§195.573(e) e. The operator's procedure did not include verbiage on the criteria if a deficiency involves a pipeline under an integrity management program and verbiage on what the intervals are for completing repairs on deficiencies.

§195.575 The operator's procedure did not include verbiage on what facilities require electrical isolation and what inspections, tests and additional safeguards are required.

§195.577 The operator's procedure did not include verbiage about designing and installing cathodic protection systems to minimize effects on existing adjacent metallic structures.

§195.579(c) The operator's procedure did not include verbiage about checking adjacent pipe when internal corrosion is found.

§195.589 (1) The operator's procedure did not include verbiage on the criteria for records retention periods for corrosion control information.

(2) The operator's procedure did not include verbiage about documenting all inspections performed under §195.583, even when no corrective action is needed.

Best Practice:
Are the breakout tanks equipped with high level alarms?

Comments:

N/C - Team O&M was for review of the operator's O&M manual only.

Note:
How often are they checked?
Is the check all the way back to the SCADA center to ensure the hardware between the sensor and SCADA is good?

Best Practice:

Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:

Does the operator's damage prevention program include pro-active liaison with local school officials, where the pipeline traverses or is adjacent to, school property?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:

Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:

Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:
Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:
Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:
Does the operator's damage prevention program include actions to protect their facilities when directional drilling or boring operations are conducted in proximity to the facilities?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Best Practice:
NPRM Qualification of Pipeline Personnel
Are trained/qualified personnel used for pipeline locating & marking?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

Note: Are contractors used? What does their training consist off? How is quality control ensured when using a third party?

Best Practice:

What factors are considered in determining the need for and timing of pigging and close interval surveys?

Comments:
N/C - Team O&M was for review of the operator's O&M manual only.

FIELD REVIEW FOR LIQUID PIPELINES

PART 195 - FIELD REVIEW		S	U	N/A	N/C
§195.262	Pumping Stations				X
§195.262	Station Safety Devices				X
§195.308	Pre-pressure Testing Pipe - Marking and Inventory				X
§195.403	Knowledge of Operating Personnel				X
§195.410	Right-of-Way Markers				X
§195.412	River Crossings				X
§195.557	Cathodic Protection (test station readings, other locations to ensure adequate CP) levels)				X
§195.573	Pipeline Components Exposed to the Atmosphere				X
§195.573	Rectifiers, Reverse Current Switches, Diodes, Interference Bonds				X
§195.420	Valve Maintenance				X
§195.420	Valve Protection from Unauthorized Operation and Vandalism				X
§195.426	Scraper and Sphere Facilities and Launchers				X
§195.428	Pressure Limiting Devices				X
§195.428	Relief Valves - Location - Pressure Settings - Maintenance				X
§195.428	Pressure Controllers				X
§195.430	Fire Fighting Equipment				X
§195.432	Breakout Tanks				X
§195.434	Signs - Pumping Stations - Breakout Tanks				X
§195.436	Security - Pumping Stations - Breakout Tanks				X
§195.438	No Smoking Signs				X

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

RECORDS REVIEW FOR LIQUID PIPELINES

Operator's Name: ____________________ **Inspection Unit:** __________

Location: ____

Inspector's Name: ____________________ **Date:** __________

PART 195 - RECORDS REVIEW		S	U	N/A	N/C
§195.5	Conversion to Service				X
§195.5(a)(1)	Testing to Verify MOP (ASME<Appendix N)				X
§195.5(a)(2)	Inspection of Pipeline Right-of-Way				X
§195.5(c)	Pipeline Records (Life of System)				X
	Pipeline Investigations				X
	Pipeline Testing				X
	Pipeline Repairs				X
	Pipeline Replacements				X
	Pipeline Alterations				X
§195.52	Telephonic Reports to NRC (800-424-8802)				X
§195.54(a)	Written Accident Reports (DOT Form 7000-1)				X
§195.54 (b)	Supplemental Accident Reports (DOT Form 7000-1)				X
§195.56	Safety Related Conditions				X
§195.57	Offshore Pipeline Condition Reports				X
§195.59	Abandoned Underwater Facility Reports				X
§195.204	Construction Inspector Training/Qualification				X
§195.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers				X
§195.214(b)	Test Results to Qualify Welding Procedures				X
§195.222	Welder Qualification				X
§195.234(b)	Nondestructive Technician Qualification				X
§195.589	Cathodic Protection				X
§195.567	Test Leads				X
§195.262(c)	Testing of Safety Devices at Pump Stations prior to Service				X
§195.266	Construction Records				X
§195.266(a)	Total Number of Girth Welds				X
	Number of Welds Inspected by NDT				X
	Number of Welds Rejected				X
	Disposition of each Weld Rejected				X
§195.266(b)	Amount, Location, Cover of each Size of Pipe Installed				X
§195.266(c)	Location of each Crossing with another Pipeline				X
§195.266(d)	Location of each buried Utility Crossing				X

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory   **U - Unsatisfactory**   **N/A - Not Applicable**   **N/C - Not Checked**

PART 195 - RECORDS REVIEW (Cont.)		S	U	N/A	N/C
§195.266(e)	Location of Overhead Crossings				X
§195.266(f)	Location of each Valve and Test Station				X
§195.302/310	Record of each Pipeline Test				X
§195.304(b)	Manufacturer Testing of Components				X
§195.308	Tests on Pre-tested Pipe				X
§195.402(c)(4)	Determination of Areas requiring immediate response for Failures or Malfunctions				X
§195.402(c)(10)	Abandonment of Facilities				X
§195.402(c)(12)	Establishment/Maintaining liaison with Fire, Police, and other Emergency Agencies				X
§195.402(c)(13)	Review of work Performed by Personnel				X
§195.402(d)(1)	Response to Abnormal Pipeline Operations				X
§195.402(d)(5)	Review of Personnel Response to Abnormal Operations				X
§195.402(e)(1)	Notices of Emergencies				X
§195.402(e)(7)	Notifications to Fire, Police, and other Public Officials of an Emergency				X
§195.402(e)(9)	Post Accident Reviews				X
§195.403(a)	Employee Training				X
§195.403(b)	Annual Review of Personnel Performance				X
§195.403(c)	Verification of Supervisor Knowledge				X
§195.404(a)(1)	Maps or Records of Pipeline System				X
§195.404(a)(2)	Maps/Records of Crossings of Roads, Railroads, Rivers, Utilities and Pipelines				X
§195.404(a)(3)	MOP of each Pipeline				X
§195.404(a)(4)	Pipeline Specifications				X
§195.404(b)(1)	Pump Station Daily Discharge Pressure				X
§195.404(b)(2)	Abnormal Operations (§195.402)				X
§195.404(c)(1)	Pipe Repairs				X
§195.404(c)(2)	Repairs to Parts of the System other than Pipe				X
§195.406(a)	Establishing the MOP				X
§195.412(a)	Inspection of the ROW				X
§195.412(b)	Inspection of Underwater Crossings of Navigable Waterways				X
§195.413	Inspection of Pipelines in Gulf of Mexico				X
§195.573(b)	External Corrosion Control - Bare Pipelines				X
§195.573(a)	External Corrosion Control - Protected Pipelines				X
§195.573(c)	Inspection of Rectifiers				X
§195.569	Inspection of Exposed Pipelines (External Corrosion)				X
§195.579	Corrosive Liquid being Transported				X
§195.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment				X
§195.579(c)	Inspection of Removed Pipe for Internal Corrosion				X
§195.420(a)	Inspection of Valves necessary for Safe Operation				X
PART 195 - RECORDS REVIEW (Cont.)		S	U	N/A	N/C

EVALUATION REPORT OF A LIQUID PIPELINE CARRIER

S - Satisfactory **U - Unsatisfactory** **N/A - Not Applicable** **N/C - Not Checked**

§195.420(b)	Inspection of Mainline Valves				X
§195.422	Pipeline Repair Records				X
§195.428(a)	Inspection of Overpressure Safety Devices				X
§195.428(b)	Inspection of Relief Devices on HVL Tanks				X
§195.430	Inspection of Fire Fighting Equipment				X
§195.432	Inspection of Breakout Tanks				X
§195.440	Record of Continuing Educational Program				X
§195.442(c)(2)	List of Current Excavators				X
§195.442(c)(2)	Record of Notification of Public/Excavators				X
§195.442(c)(3)	Record of Notifications of planned excavations. (One -Call Records)				X

Oil Pollution Act High Impact Inspection (49 CFR 194)

Field Verification of Facility Response Plan Information		Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number _______ Approval Date___________ [See Guidance OPA-1]			
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]			
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]			
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]			

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

U.S. Department of Transportation

Research and Special Programs Administration

Inspection Summary

Central Region Office — Office of Pipeline Safety

To: Region Director JH

Date: 4/17/02

P.A.

From: Phil Archuletta, Staff Engineer

Company Inspected: LAKEHEAD PIPE LINE CO INC

Operator: LAKEHEAD PIPE LINE CO INC

Type of Service: Interstate Liquid

Inter-Regional System:	System Description	Inspection I.D.
CRUDE SYSTEM 2	30" line from Superior, WI across the Upper Peninsula of MI to the Canadian/US border, near Marysville, MI (in the CE region the system includes Unit #132: Superior, Unit #135: Escanaba & Unit #295: Bay City)	93251 (Headquarters) 91790 (Field) 91791 (Field)

Dates of Inspection: 5/7/01 - 5/12/01 (Headquarters); 5/14 - 5/18(Records & Field); 6/11 (Records)

Location: Duluth, MN (HQ NHIF), Duluth, MN (records); Iron Wood, MI (PLM records); Escanaba, MI (records); Bay City, MI (records); States of Michigan and Wisconsin (field facilities)

Facilities Inspected: Phil Archuletta and David Barrett from CE OPS conducted a CE-regional system inspection of Lakehead Pipeline Company's Crude System #2. The inspection was conducted using the "New High Impact Form (NHIF)" inspection form. All documents and records requested were presented and were satisfactory with the exception of items noted below under "Deficiencies Found."

Lakehead Pipe Line's facilities for this unit consist of the following:

- Approx. 452 miles of 30" from Superior, WI to Lewiston, MI
- Approx. 187 miles of 30" from Lewiston, MI to the US/Canada border
- 11 Pump stations located at Superior, Ino, Saxon, Gogebic, Iron River, Rapid River, Manistique, Gould City, Naubinway, Mackinaw and Indian River
- 1 main delivery facility located at Marysville, MI.

The actual physical facilities inspected included:

- 30" Line from Superior, WI to Indian River, MI
- Pump stations located at Superior, Ino, Saxon, Gogebic, Iron River, Rapid River, Manistique, Gould City, Naubinway, Mackinaw and Indian River.

A number of stops were made at valve settings, pump stations and points along the pipeline segments where C/P readings could be taken.

Persons Interviewed:

Refer to page 1 of the attached "High Impact" form for a listing of persons interviewed.

Deficiencies Found:

Lakehead Pipe Line's O&M Manuals were not evaluated. This operator was scheduled in 2001 for an inspection of several systems and the O&M Manuals were reviewed at the operator's headquarters in conjunction with the headquarters portion of the system inspections.

A review of Lakehead Pipe Line's records and field facilities identified the following deficiencies:

Headquarters Issues:

A. Notice of Amendment Items:

1. § 195.401 General requirements.

   § 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

   (a) LPL procedures need revision to include verbiage about including first discovery reports from all sources such as the public, employees, contractors, etc. and not just reports made to LPL's Control Center.

   (b) LPL has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of LPL's pipeline systems, especially with regard to internal corrosion control procedures and remedial actions taken. However, LPL has not formalized the process by inclusion of specific verbiage in LPL's O & M manual.

2. § 195.402 Procedural manual for operations, maintenance, and emergencies.

Field Issues:

During the federal portion of the field inspection, it was discovered that some signs displayed a telephone number which when called should have automatically forwarded the call to LPL's main Control Center. However, at the time of the inspection, the calls were not being automatically forwarded as intended. LPL investigated the problem and the situation has been corrected so that all calls are now forwarded to LPL's main Control Center. Since LPL has now had a merger/re-organization, LPL (now Enbridge Energy Partners, Inc.) will be replacing all signs along their ROW with new signs displaying one appropriate contact number.

B. Warning Letter Items:

1. § 195.222 Welders: Qualification of welders.

Each welder must be qualified in accordance with Section 3 of API Standard 1104 or Section IX of the ASME Boiler and Pressure Vessel Code, except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not requalify under that earlier edition.

Ironwood PLM Office - Review of the Welder Qualification Record for Mr. Russell A. Paquette indicated that Mr. Paquette did not follow Welding Procedure Specification (WPS) UF-28 when taking the welder qualifying test on 03/06/2000.

2. § 195.410 Line markers.

§ 195.410(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

§ 195.410(a)(2) The marker must state at least the following: "Warning" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline" (in lettering at least 1 inch high with an approximate stroke of one-quarter inch on a background of sharply contrasting color), the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

LPL's markers displayed an incorrect company contact number or was missing a contact number at the following locations:

1. MP1222.048 (markers on each side of road)
2. MP1238.153 (markers on each side of road)

LPL's marker was missing at the following location:

MP 1393.759 Indian River - East Side

3. § 195.434 Signs.

Each operator shall maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and an emergency telephone number to contact.

LPL's signs displayed an incorrect company contact number or was missing a contact number at the following locations:

a. M/L Valve at MP1105.98
b. M/L Valve at MP1115.55
c. M/L Valve at MP1127.69
d. M/L Valve at MP1173.20
e. M/L Valve at MP1183.78
f. M/L Valve at MP1212.18
g. M/L Valve at MP1299.72

LPL's signs were missing at the following locations:

h. M/L Valve at MP1307.35
i. M/L Valve at MP1343.70
j. M/L Valve at MP1396.39

C. Letter of Concern Item:

§ 195.420 Valve maintenance.

§ 195.420(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

A open/close indicator rod on a mainline valve was inoperable at the following location: M/L Valve at MP1238.153 (Wolf Lake Road). The valve itself was in good working order.

D. Notice of Probable Violation and Proposed Compliance Order Items:

§ 195.401 (b) General requirements.

§ 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

During the field inspection it was observed LPL's right-of-way was partially obstructed from aerial view at the following locations:

a. MP1164.60 - west side
b. MP1238.153
c. MP1247.89
d. MP1260.166 - west side
e. MP1280.307 - west side
f. MP1387.577 - east side
g. MP1429.301 - west side
h. MP1439.71 - Black River crossing (both sides)
i. MP1460.187
j. MP1465.50 - east side

Right-of-way inspections conducted by the operator under § 195.412(a) should have noted that an aerial view of the right-of-way was partly blocked by overgrowth.

Conclusions/Recommendations:
Lakehead Pipeline has submitted documentation regarding action taken on the following items under paragraph A (copies of documentation are attached):

Item 1.(a) - Copy of intended revision (2 sheets) to Procedure"Notification of Safety Concern". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a
Notice of Amendment for this item.

Item 1.(b) - Copy of intended revision to Procedure 08-02-01, "Corrosion Control"; page 3 of 9 - "Monitoring". LPL has not submitted the actual final revised procedure. Recommend that LPL
be issued a Notice of Amendment for this item..

Item 2. - Copy of intended revision to Procedure "Abnormal Operation Procedure Review Process". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 3. - Copy of intended revision to Procedure 09-01-01, "Overview of Tank Maintenance"; page 2 of 3. LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 4. - Copy of intended revision to Procedure 03-02-01, "Right-Of-Way Inspections"; page 5 of 5 - "Valve Inspections". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 5. [for .432(b)] - Copy of intended revision to Procedure 09-02-02, "Tank Inspections";

page 2 of 7 - "Records - Routine Inspections - Monthly". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 5. [for .432(c)] - Copy of intended revision to Procedure 09-02-02, "Tank Inspections"; page 1 of 7 - "Requirements - Inspection Frequency". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

It is recommended that Lakehead Pipe Line be issued a Warning Letter for all items listed under paragraph B.

It is recommended that Lakehead Pipe Line be issued a Letter of Concern for the item listed under paragraph C.

It is recommended that Lakehead Pipe Line be issued a Notice of Probable Violation and a Compliance Order for the items listed under paragraph D. The Compliance Order would be to develop a plan and schedules for clearing of right-of-way.

TO: DORI 218.725.0405

ENBRIDGE Jim K Huber on 05/16/2001 01:53 PM

To: John W Hayes/IPL@IPL, Brad Shamla/IPL@IPL, David W Bryson/IPL@IPL, Mel Wyness/IPL@IPL, Allan D Baumgartner/IPL@IPL, Ian C Melligan/IPL@IPL
cc: Janet L Huggett/IPL@IPL
Subject: Proposed wording for Notification of Safety Concerns

As a line item noted by the DOT Audit, we may be deficient in addressing miscellaneous safety concerns called in by the public (this may include washed out pipe, unauthorized activity on the pipeline, etc.

The following is a draft procedure for the Database:

Notification of Safety Concern

When notified of a concern of a potential unsafe or hazardous condition:

1. Continue to operate the pipeline
2. Contact *the nearest station* on-call personnel immediately
3. Complete Incident Receiving Report Form

To address this concern, I propose we add the following warning to the Incident Information Form, p 3, Hazard Warning (to caller):

" We operate high pressure petroleum pipelines in your vicinity. It appears from your description and from observations of our control system, there is no immediate hazard from our pipelines. However, as a precautionary measure, we will dispatch company personnel to investigate the situation."

I also propose we add the following information to the Incident Information Form, p 4, Immediate Steps:

Company Personnel notified: ____________________ Time:__________
Company Personnel providing "All Clear": ____________________ Time:__________

Description of Follow Up Required (CCO Supervisor):____

Your feedback will be greatly appreciated. Please let me know what you think.

ENBRIDGE

Jim K Huber on 05/18/2001 12:48 PM

To: Ian C Melligan/IPL@IPL, Janet L Huggett/IPL@IPL
cc:
Subject: Re: Notification of Safety Concern

195.401(b)
Q.20

Ian C Melligan

Next Previous Return Feedback

Notification of Safety Concern

When notified of a concern of a potential unsafe or hazardous condition: — popup

1. Continue to operate the pipeline
2. Contact the nearest station on-call personnel immediately
3. Complete Incident Receiving Report Form — hot link

Doug *Note: Incident Report Receiving Form will be modified to include space for potential or unsafe conditions on the pipeline which will spawn follow up action by the Company.

This form will be extensively revised to record:
- notification and/or all clear report (who, when)
- false alarm, safe condition & followup requirements
- response to caller

includes but is not limited to:
- unauthorized personnel on ROW or in facility
- exposed pipe
- station strobe light or horn sounding
- construction activity

Pipeline Integrity must recommend a prevention and maintenance program for internal corrosion by:

- determining treatment needs, concentrations and application methods
- selecting suitable chemical properties
- selecting appropriate in-line tools, if required
- selecting treatment locations

NOTE: Past performance and present day monitoring of inhibitor effectiveness continually affect these decisions.

195.401(b)

Q.31

Monitoring
Take beta foil readings at least 10 times per year with intervals not exceeding six weeks; however, make every effort to take readings once per month.

Further description of remedial action resulting from discovery of internal corrosion (i.e., beta foil readings) to be added here (DOT HQ Audit May 9/01). 195.401 (b)

NOTE: During cleaning and/or inhibitor injections, Pipeline Integrity may increase the frequency of beta foil readings.

NOTE: For more information on the company's beta foil and corrosion inhibitor plan, contact Pipeline Integrity.

Records

Excavation Inspection and/or Repair Report
Use the Excavation Inspection and/or Repair Report (CAN), or the Corrosion Inspection Report in the PLM Activity Report database (USA), to document both "as found" and "as left" conditions of exposed mainline or station piping during excavations.

USA

Distribute the Corrosion Inspection Report as follows:

1. Electronic original retained in Lotus Notes database.
2. Hard copy printed and filed at district/area office.
3. Hard copy printed and filed at Engineering.

USA

District office must retain Corrosion Inspection Reports for a minimum of two years.

ENBRIDGE Jim K Huber on 05/18/2001 12:42 PM

195.402(d)(5)
Q.7

To: Ian C Melligan/IPL@IPL, Janet L Huggett/IPL@IPL
cc:
Subject: Re: Abnormal Operation Procedure Review Process

Changes to the procedure as noted.

Ian C Melligan

Abnormal Operation Procedure Review ~~Process~~

~~At any time~~ After an initiated response of an Emergency Procedure *or abnormal operation* occurs:

1. *Within 24 hours* perform an initial procedure review to determine effectiveness of the procedure

   The initial procedure review shall include the following personnel:

   - Control Centre Coordinator on-shift during abnormal operation
   - Control Centre Operator on-shift during abnormal operation

2. If ~~review determines that~~ the procedure requires modification, notify ~~document and acquire approval from~~ Supervisor
3. Supervisor will initiate procedure change
4. Procedure will be modified and personnel shall be informed of change

Doug * *NOTE: CCO will add hot links which will activate this page to all procedures in this database descibing action during Emergency or abnormal operation .*

- D04-102, Painting, Coating and Lining
- D05-101, Berm, Containment
- D05-201, Foundation, Oil Storage Tank
- D05-401, Platforms, Stairs and Ladders
- D06-102, Piping Design, Station and Terminal
- D08-101, Oil Storage Tank
- D08-102, Oil Storage Tank, Roof
- D08-103, Oil Storage Tank, Accessories

Operating & Maintenance Procedures:
- Book 1: General Reference
- Book 2: Safety
- Book 4: Welding

Emergency Response Plan (ERP)
Waste Management Plan

Industry
American Petroleum Institute (API):
- API Guide for Inspection of Refinery Equipment, Chapter 13, Atmospheric and Low Pressure Storage Tanks
- API 650, Welded Steel Tanks for Oil Storage
- API 651, Cathodic Protection of Above Ground Storage Tanks
- API 652, Lining of Above Ground Petroleum Storage Tank Bottoms
- API 653, Section 4—Inspection
- **API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning and Stray Currents (DOT HQ Audit May 11/01) 195.432**
- API 2015, Safe Entry and Cleaning of Petroleum Storage Tanks
- API 2026, Safe Descent Onto Floating Roofs of Tanks in Petroleum Service
- API 2027, Ignition Hazards Involved in Abrasive Blasting of Atmospheric Storage Tanks in Hydrocarbon Service
- API 2207, Preparing Tank Bottoms for Hot Work

195.432
Q. 35

Canadian Council of Ministers of the Environment (CCME):
- Environmental Code of Practice for Aboveground Storage Tank Systems Containing Petroleum Products

195.420(b)
Q.40

USA

Valve Inspection

Mainline valves, including remotely operated valves, must be inspected according to Maximo MP107 and MP256 at least twice during each calendar year at intervals not to exceed 7½ months.

In addition to the above, at least ~~once~~ twice each year the remote operation (i.e., open and close from control center) of remotely operated mainline valves must be verified according to Maximo MP179.

USA

Overpressure Safety Devices

Devices that limit, regulate and/or control maximum operating pressure must be inspected, tested or calibrated regularly according to Maximo:

- EP244 for pressure relief valves
- EP268 for pressure transmitters
- EP269 for pressure switches
- ET313 for OQT pressure allowable setpoints
- MP251 for pressure relief valves in crude service
- MP255 for pressure relief valves in NGL service
- MP290 for OQT pressure control valve system
- MP251 for OQT relief valve inspection and testing

Engineering, in cooperation with Operations employees, is responsible for determining if any device becomes inadequate in capacity and/or reliability for its intended purpose, and for ensuring the device is upgraded or replaced.

Records

CAN

Aerial Patrol Reports

Patrol pilots must document aerial inspections in the Aerial Patrol Report database. The report summarizes inspection dates and any abnormal conditions observed. Aerial Patrol Reports are permanently retained in the database and may be filed and at the regional office responsible for the area covered in the report.

NOTE: For Enbridge Pipelines (NW) Inc, the Aerial Patrol Report database is in the Lotus Notes NW Forum.

- five years of experience in inspecting above-ground storage tanks in the petroleum or chemical industries

Table 1
Types and Frequencies of Tank Inspections

Type of Inspection	Maximum Interval	Done by
Routine In-Service	Monthly	local terminal operations employees
Routine In-Service	Annually	local terminal operations supervisor PLM supervisor or designate
Formal In-Service	5 years[1]	authorized API inspector[2]
Formal Out-Of-Service	20 years[1,3]	inspection team and authorized API inspector[2]

NOTES
1 More frequent inspections may be required due to corrosion.
2 May be a person who is not a company employee.
3 Frequency may be extended if a risk-based inspection (RBI) assessment is done according to API 653.

Evaluation—Repairs—Alterations

After routine inspections, evaluate documentation to determine:

- requirement for leveling tank
- extent of repairs required
- repair method
- requirement for hydrostatic testing

Refer major maintenance or operational issues to the station chief/terminal supervisor.

The inspection team must consult with Engineering on integrity issues that require repairs or alterations to a storage tank.

Records

Routine Inspections

Monthly

Check tank exteriors, including roofs, and document conditions in the terminal log. **Further clarification of conditions for conducting monthly routine inspections on tanks as well as corrective action when problems are found to be added here (DOT HQ Audit May 11/01) 195.432**

195.432 Q.35

BOOK 3: PIPELINE FACILITIES

ENBRIDGE

Section
STANDARDS

09-02-02
Subject Number

Subject
Tank Inspections

Purpose

Tank inspections confirm the structural integrity of the tank and its continued fitness for use.

Requirements

Inspection Frequency

Inspect in-service and out-of-service crude oil storage tanks on a schedule consistent with the recommended guidelines of API 653, Section 4–Inspection. Table 1 summarizes the types and frequencies of tank inspections. **Requirements for inspecting physical integrity of in-service aboveground breakout tanks (bullet tanks) according to API 2510, Section 6, to be added here (DOT HQ Audit May 11/01) 195.432**

195.432
Q. 35

Qualifications

Employees assigned to do a Routine-In-Service Inspection must be familiar with tank farm operation, the tank and the characteristics of the product stored, e.g., terminal gauger, terminal supervisor, station chief, PLM supervisor or designate.

Inspection teams assembled to do a Formal In-Service or Formal Out-of-Service Inspections must be comprised of knowledgeable employees from regional/district offices, terminals/stations, and Pipeline Maintenance (PLM) or Engineering. One member of the inspection team must be certified as an Authorized API inspector as described in API 653.

Authorized API Inspectors

Authorized API inspectors must have education and experience equivalent to at least one of the following:

- degree in Engineering and one year of experience inspecting tanks, pressure vessels or piping
- two-year certificate in Engineering or Technology from a technical college, and two years of experience in operation, construction, repair or inspection, of which one year must be in the inspection of tanks, pressure vessels or piping
- equivalent of high school education and three years of experience in construction, repair, operation or inspection, of which one year must be in the inspection of tanks, pressure vessels or piping

Name of Operator:	**Lakehead Pipe Line Company Inc.**

HQ Address: Lakehead Pipe Line Company Inc. 1100 Louisiana, Suite 2950 Houston, TX. 77002	**System/Unit Name Address:** Crude System # 2
Co. Official (Pres or VP) Dan C. Tutcher; President **Telephone number:** 713-650-8900 **Fax number:** 713-650-3232 **Emergency Telephone:** 800-858-5253	**Telephone number:** **Fax number:** **Emergency Telephone:** 800-858-5253

Operator ID: 11169	**Unit ID:** 153 (System ID)	**Activity ID:** 93251, 91790, 91791

Unit IDs of adjacent Operator units:

Persons Interviewed	Titles	Phone Numbers
Refer to attached copies of		
attendance sheets.		

OPS Representative(s): David Barrett and Phil Archuletta

Company system maps - (copies for regional files, yes / no): Yes, placed in operator's file.

System/Unit Description:

System: Superior, WI east across the MI Upper Peninsula and then southeast to the Canadian border near Marysville, MI.
The system includes the following Central Region units:

Unit # 1323	Superior
Unit # 1353	Escanaba
Unit # 2953	Bay City

Portion of Unit Inspected:

Operator headquarters in Duluth, MN.
Pipeline facilities from Superior, WI east across the MI Upper Peninsula and then southeast to the Canadian border near Marysville, MI. Inspection included pump stations at Superior, Ino, Saxon, Gogebic, Iron River, Rapid River, Manistique, Gould City, Naubinway, Mackinaw and Indian River.

Was a Team O&M inspection completed previously? No	**If yes, document date?** / /

Note: If a Team O&M inspection was completed within the five (5) years, it is not necessary to review the entire O&M manual. However, modifications to the manual should be reviewed.

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description LAKEHEAD HEADQUARTERS INSPECTION
Date 5/8 **Location** Duluth, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	Staff Engineer	U.S. DOT-OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Dave Barrett	Engineer	US DOT-OPS	816 329 3817	david.barrett@rspa.dot.gov
3	Brian Pierzina	Sr. Engineer	MN OPS	218-327-4218	brian.bierzina@state.mn.us
4	BOYD HAUGROSE	Eng. Spec.	MNOPS	218-847-7367	boyd.haugrose@state.mn.us
5	Doug A Klein	Safety & Compliance	Enbridge (U.S.)	218-725-0444	doug.klein@uspl.enbridge.com
6	Dave McNeill	Supervisor Integrity	Enbridge (US).	218-725-0595	dave.mcneill@uspl.enbridge.com
7	John Sobojinski	Operations Services Manager	Enbridge (US)	218-725-0505	John.Sobojinski@uspl.enbridge.com
8	Janet Huggett	Sr. Technical Writer	Enbridge Pipelines	780-420-5142	Janet.Huggett@cnpl.enbridge.com
9	VINCE KOLBUCK	ENGINEER	ENBRIDGE U.S.	218-725-0563	vince.kolbuck@uspl.enbridge.com
10	Tom Lohman	engineer	Enbridge US.	218 725-0568	tom.lohman@uspl.enbridge.com
11	Don Scott				
12	Tanis Elm	Sen. Engineer	Enbridge US	218 725-0495	tanis.elm@uspl.enbridge.com
13	GAIL FOLLIS	ENG. SERVICES	ENBRIDGE US	218-725-0536	GAIL.FOLLIS@USPL.ENBRIDGE.COM
14	Nadine Lohman	Design & Serv. Clerk	Enbridge US	218-725-0537	Nadine.LOHMAN@USPL.Enbridge.com
15	ERIC A. WILLIAMS	SAFETY + COMPLIANCE	ENBRIDGE U.S.	219-922-3133	ERIC.WILLIAMS@USPL.ENBRIDGE.com

16	Dean Carpenter	Corp. Eng. Services	UNBRIDGE US 218-725-0525		dean.carpenter@uspl.ENBRIDGE.com
17	Terri Breitzmann	Supervisor Eng. Design & Services	ENBRIDGE US 218-725-0511		TERRI.BREITZMANN.@USPL.ENBRIDGE.com
18	Kenneth Wergeland	Engineering	Enbridge US 218-725-0510		Ken.Wergeland@USPL.Enbridge.Co.
19	Karl Hodil	"	ENBRIDGE US 218-725-0507		Karl.hodil@uspl.enbridge.com
20	JAY A JOHNSON	OPS. SERVICES	ENBRIDGE US 218/725-0512		jay.johnson@ "
21.	LYNNE HARRINGTON	TRAINING COORDINATOR	ENBRIDGE (US)	(218)725-0119	LYNNE.HARRINGTON@USPL.ENBRIDGE.COM
22.	Denise Hamsher	Mgr Business Services	"	218 725-0140	denise.hamsher@uspl.enbridge.com
23.	Jim Stien	Project Mgr.	"	(218) 725-0481	jim.stien@uspl.enbridge.com
24	Carl Mikkola	Sr. Integrity Eng.	"	218 725-0560	carl.mikkola@uspl.enbridge.com
25.	NANCY R. BRYCE	SR. SYSTEMS ANALYST	"	218-725-0150	nancy.bryce@uspl.enbridge.com

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description Records Review

Date 8-27-01 **Location** Duluth, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	General Engineer	US DOT - OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Kimberly J. Harris	Sr. Corrosion Tech	LPL/ Enbridge Energy Partners	219-922-3133 x202	Kimberly.Harris@uspl.Enbridge.com
3	John Sobojinski	Manager-Compliance + Risk Management	Enbridge (US)	218-725-0505	John.Sobojinski@USPL.Enbridge.com
4	David McNeill	Supervisor Pipeline Integrity	Enbridge (US)	780-420-8731	
5	Gary Haubrich	Tech Supervisor	LPL	218-759-6614	
6	Randy Wilberg	Safety Training Compliance	Enbridge U.S.	715-394-1412	Randy.Wilberg@uspl.enbridge.com
7	Todd Gilseth	Safety Analyst	" "	218-759-6615	Todd.Gilseth@USPL.Enbridge.com
8	Doug A. Klein	Safety Team Leader	Enbridge U.S	715-394-1437	doug.klein@uspl.enbridge.com
9	Jay A Johnson	Compliance Coordinator	" "	218/725-0512	jay.johnson@uspl.enbridge.com
10	Dave Barrett	Engineer	OPS	816-329-3817	david.barrett@rspa.dot.gov
11	Brian Pierzina	Sr. Engineer	MNOPS	218-327-4218	brian.pierzina@state.mn.us
12					
13					
14					
15					

IRONWOOD PLM

Leo Zalaznik	Escanaba PLM	906-789-1221
Doug A Klein	Duluth, MN.	218-725-0444
MARC A. CURRY	BAY CITY, Mi	989-684-0160
David C. Mussatti	Ironwood MI	906-6932-0949

ESCANABA

MARC A. CURRY	BAY CITY, Mi	989-684-0160
AL ALEKNAVICIUS	ESCANABA, MI	906-789-1221 ext 13
Blake C. Olson	" "	" ext 15
Leo Zalaznik	Escanaba PLM	906-789-1221 ext 2:
MIKE PARADISE	ESCANABA PLM	" "
Don Tennant	Escanaba PLM	(906) 789-1221 ext 2
Lynn BUNKER	Bay City Mi	989-684-0160

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description RECORDS REVIEW
Date 6-11-01 **Location** BAY CITY DISTRICT - LAKEHEAD P/L

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	GENERAL ENGINEER	DOT-RSPA-OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Dave Barrett	Engineer	DOT/OPS	816-329-3817	david.barrett@rspa.dot.gov
3	MARC A. CURRY	SAFETY/COMPLIANCE	LAKEHEAD	517-684-0160	marc.curry@uspl.enbridge.com
4	Mike Moeller	Engineer	Enbridge (U.S.)	517 684 0160	mike.moeller@uspl.enbridge.com
5	JAY JOHNSON	OPS SERV. COORD.	ENBRIDGE US	218/725-0512	jay.johnson@uspl.enbridge.com
6	Doug Klein	Safety & Compliance	Enbridge U.S.	218-725-0144	Doug.Klein@uspl.enbridge.com
7	EDWARD McKENDRY	TECH SUPV	ENBRIDGE U.S.	989-6840160	ed.mckendry@uspl.enbridge.com
8	Lynn Downey	Right of Way Agent	ENBRIDGE U.S.	989 684 0160 (28)	lynn.downey@uspl.enbridge.com
9	John Klarich	PLM Supervisor	LAKEHEAD	517-684-0160	John.Klarich@uspl.enbridge.com
10	LYNN BUNKER	Corrosion TECH	LAKEHEAD	517-684-0160	lynnbunker@uspl.enbridge.com
11					
12					
13					
14					
15					

MOP/Overpressure Protection

Overpressure protection is essential to protect the pipeline from unexpected events. The operator should have procedures in place to ensure that the overpressure protective devices are adequate and in good working condition.

195.406(a)(1) Maximum Operating Pressure - Determining the MOP from design or test pressure or integrity calculations.

195.404(a)(3) Maps and Records - Each operator shall maintain current records of the maximum operating pressure of each pipeline system.

G-Q1) Does the operator have records to support the MOP applied to each line segment?

R1) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q1) Headquarters	X			
Q1) Field			X	
R1) Headquarters	X			
R1) Field			X	

1) Comments: The MOP of each pipeline segment was established by hydrostatic testing. The hydrostatic tests accounted for elevation differences and the characteristics of the products transported. System dynamic models are used to help determine pipeline parameters such as pressure setpoints. Different scenarios are run on the models to determine if any pressure changes are required. Pressure setpoints and allowances are determined by Lakehead's engineering department. Pump station base maximum discharge (BMD) pressures are set equal to are less than the established MOP for the entire line segment. For surge pressures, a first alarm warning is set at 5psig above BMD, a cascade shutdown of units at the station PLC is set at 25 psig above BMD, a cascade shutdown of units by the SCADA center is set at 35 psig above BMD and a complete shut-down of the entire pipeline is set at 65 psig above BMD or 110% BMD.

195.404(b)(1) Record of Discharge Pressure - Actual operating pressures representing three years of data.

G-Q2) Does the operator's pressure recording system retain sufficient details of pressure events, so as to exhibit pressure spikes that may have breached the MOP?

R2) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q2) Headquarters			X	
Q2) Field	X			
R2) Headquarters			X	
R2) Field	X			

2) **Comments:** Lakehead has begun a program to replace pen & ink pressure recorders with digital pressure recorders. Currently, 40 out of approximately 100 recorders have been replaced. These are six channel digital recorders which look at pressure every second, records the pressure every minute and records the highest and the lowest pressure within that one minute span, however, the exact time of each high/low is not kept. If an event causes a cascade shut-down, then the recorders capture all pressures between 5 minutes before and 5 minutes after the shut-down. The pressure data is stored on zip disks and one year's worth of data can be stored on one zip disk. The data is also sent and recorded at Lakehead's headquarters server as a backup.

195.428(a) Overpressure Safety Devices - Each operator shall at intervals not exceeding 15 months, but at least each calendar year, or in case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good working condition, and is adequate from the stand point of capacity and reliability of operation for the service in which it is used.

G-Q3) Have pressure safety devices been checked for pressure accuracy in one year intervals, or six month intervals for highly volatile liquids?

R3) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q3) Headquarters			X	
Q3) Field	X			
R3) Headquarters			X	
R3) Field	X			

3) **Comments:** Pressure safety device inspections are recorded in Maximo. Station safety devices (pressure switches and transmitters) are checked semi-annually. Pressure relief valves are checked annually. Verified by records review at Duluth and Escanaba.

Field: Bay City District - The only reliefs in this district are located on the discharge side of the injection pump for the sump tanks. These reliefs are checked once annually.

195.128 Station Piping - Must meet applicable requirements if subjected to system line pressure.

G-Q4) Have the appropriate pressure controlling devices been installed to protect the lower-pressure piping in the manifold and/or at pump stations?

R4) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q4) Headquarters	X			
Q4) Field	X			
R4) Headquarters			X	
R4) Field			X	

4) Comments: Pressure controlling device procedures / criteria are contained in Lakehead's Engineering Standard D12-104. Lakehead uses a tiered approach to pressure control alarming/shut-down. The tiers are 1) alarm, 2)shut-down and 3)high-high shut-down (a station shut-in will also occur). Redundant transmitters are used to send data back to the PLC. The PLC uses the lowest transmitter pressure reading for control. Setpoints at station PLC's are established based upon what product is being transported. Some of Lakehead's stations also use variable frequency drive pumps to control discharge pressures. Surge relief for NGL's is provided by bullet tanks located at Lakehead's Superior Terminal/Station.

195.402(d)(1) Abnormal Operation - Responding to, investigating and correcting the cause of unintended closure of valves or shutdowns; and an increase or decrease in pressure or flow rate outside normal operating limits.

195.404(b)(2) Maps and Records - Each operator shall maintain for at least 3 years daily operating records of any emergency or abnormal operation.

G-Q5) Did the safety devices function properly during abnormal operation?

R5) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q5) Headquarters	X			
Q5) Field	X			
R5) Headquarters			X	
R5) Field	X			

5) Comments: High pressure shut-down is provided at delivery points. Lakehead has a policy that if a high pressure or other abnormal event cannot be resolved in 10 minutes, then a shut-down is initiated. Verified by records review at Duluth and Escanaba.

195.402 (d)(2) Procedures for checking variations after abnormal operations - Checking for safe operation at sufficient critical locations to determine continued integrity and safe operation.

195.404(b)(2) Maps and Records - Each operator shall maintain for at least 3 years daily operating records of any emergency or abnormal operation.

G-Q6) Are procedures and forms used to document the occurrence of unscheduled shutdowns and over-pressure situations?

R6) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q6) Headquarters	X			
Q6) Field			X	
R6) Headquarters	X			
R6) Field			X	

6) Comments: Abnormal events are recorded on Pipeline Incident forms in the field. Lakehead's control center uses a "Facilities Management" (FACMAN) report for reporting such events as station unit problems, lockouts, overpressures and any significant activity that is considered outside of ordinary operations. Events generate internal memos and messages to field operations on causes, corrective actions and preventive procedures. Events involving surge relief valves are FACMAN not recorded. All FACMAN records are kept at Lakehead's Edmonton, Alberta, Canada office.

195.402(d)(5) Procedural manual for operations, maintenance, and emergencies - Abnormal Operation - Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

G-Q7) Does the procedure direct the analysis of abnormal conditions to prevent future abnormal events?

R7) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q7) Headquarters		X		
Q7) Field			X	
R7) Headquarters			X	
R7) Field			X	

7) Comments: Lakehead did not have a formal written procedure for analyzing abnormal events. Lakehead looks at what happened and why, but there was no direction as to how analysis is done on a company wide basis. Lakehead has a "PIPELINE CONTROL COMMITTEE" that meets quarterly to review philosophies, give direction/coordination and establish priorties for the control/operation of Lakehead's pipelines. The goal of the committee is to achieve a safe, efficient, environmentally sound operation compliant with regulations.

195.302(c) - Compliance deadlines for pipelines that have not been pressure tested.

G-Q8) Has the operator developed a plan for testing its pipeline systems?

R8) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q8) Headquarters			X	
Q8) Field			X	
R8) Headquarters			X	
R8) Field			X	

8) Comments: All of Lakehead's pipelines have already been tested.

195.426 Scraper and Sphere Facilities - Pressure indication and relief devices.

G-Q9) Do traps have functioning visual or audible indications of pressure to alert operating and maintenance personnel about elevated trap pressure?

R9) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q9) Headquarters			X	
Q9) Field	X			
R9) Headquarters			X	

R9) Field			X	

9) Comments: Lakehead's procedures on traps are in Lakehead's O & M Book 3, Section 08-03-01and 08-03-02. Field inspections verified that traps are provided with devices to alert personnel about high pressure in the trap.

195.262(a) Pump Station Ventilation and Warning Devices - Detecting hazardous vapors.

G-Q10) Has the operator installed warning devices in pump station buildings to warn of the presence of hazardous vapors?

R10) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q10) Headquarters	X			
Q10) Field	X			
R10) Headquarters			X	
R10) Field			X	

10) Comments: Procedures for detecting the presence of hazardous vapors are in Lakehead's Engineering Standard D12-202. At Lakehead's pump stations, there are vapor detectors located either near the units or along the interior building walls. Visual alarm on the local PLC panel. The control center also receives an alarm. The devices give a warning at 20% LEL and a alarm and shut-down at 40 % LEL. Thermal (heat) switches are provided above each pump unit for fire detection and are set at 125° F.

195.402(c)(9) Facilities not equipped to fail safe - As described in 195.402(c)(4), facilities that are located in areas that control the receipt and delivery of hazardous liquids would require an immediate response by the operator to prevent hazards to the public must be monitored... usually by SCADA if unattended.

G-Q11) Are all the unattended locations on the operator's system which control the receipt and delivery of hazardous liquids monitored?

R11) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q11) Headquarters	X			
Q11) Field	X			
R11) Headquarters			X	
R11) Field			X	

11) Comments: All remote locations are monitored by Lakehead's control center in Edmonton, Alberta, Canada. Equipment is designed to fail-safe. Lakehead has backup communication systems if the primary systems fail. A loss of communications causes local PLC's to go to limits which significantly reduces line through put rate. If communications at a remote site are lost for more than 10 minutes, then the control center will start a systematic shut-down procedure.

195.408(a) Communications System for Pipeline Information - Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline.

G-Q12) Will system operation be affected by communication outages or SCADA failure?

R12) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q12) Headquarters	X			
Q12) Field			X	
R12) Headquarters			X	
R12) Field			X	

12) Comments: Lakehead has a back-up control center located in Superior, WI. The back-up center has 5 to 6 consoles and in the event that a console fails, any one of the other consoles can be used. If for any reason, the building housing the control center at Edmonton had to be evacuated, then the control center would shut-down all pipelines and personnel would temporarily relocate to a another back-up control center at a Edmonton terminal that is approximately 15 to 20 minutes from the main control center. Control personnel would then begin a systematic re-start of all pipelines. Back-up control centers are tested a minimum of two times per year.

G-Q13) Best Practice:
Does the operator have a means to prevent controller fatigue?

13) Comments: The Lakehead control center at Edmonton, Alberta, Canada has ergonmically designed console controls, chairs and room lighting. There are two 12 hour shifts, 7:00AM - 7:00PM and 7:00PM - 7:00AM. The controllers work 2 days, 3 nights and then have 5 days off. They then work 3 days, 2 nights and have 5 days off. Controllers are provided with a tread mill for excersice and a mini-kitchen. Controllers are cross-trained there is rotation among the consoles. Normal operation is to have one operator per console per shift. There is one control center coordinator per shift to supervise the controllers.

195.134 Definition and application of the computational pipeline monitoring (CPM) leak detection system.

G-Q14) Does the operator have a leak detection system?

R14) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q14) Headquarters	X			
Q14) Field			X	
R14) Headquarters			X	
R14) Field			X	

14) Comments: Leak detection systems are provided for Lines 1, 2, 3, 5 and 13. A leak detection system for Line 4 is almost ready, the system is installed but the alarms are not active because they are fine tuning the settings. A leak detection system for Line 6 has been budgeted. Leak detection is not provided for Lines 14 and 17(probably will be done next year). The system used is a Stoner Leak Detection System which uses real time transient hydraulic modeling of the pipelines. The system compares the model with what is actually occurring on the pipelines. The sensitivity ranges vary for each line, but an example would be Line 3 where the sensitivity is 28% of total flow over 5 minutes, 11% over 20 minutes and 6% over 2 hours. The leak detection system is part of the "10 minute" rule, which means that if the reason for a leak detection indication cannot be resolved within 10 minutes, then the line will be shut-down.

195.404(c)(3) Maps and Records - Each operator shall maintain a records for two years.

G-Q15) Does the operator maintain records per the requirements of 195.404(c)(3)?

R15) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q15) Headquarters	X			
Q15) Field	X			
R15) Headquarters	X			
R15) Field	X			

15) Comments: Procedures for record keeping requirements are found in Book 1, Sections 05-01-01 and 05-02-01 of Lakehead's O & M manual. Records such as PLM Reports, Permanent Repair Reports and Corrosion Inspection Reports are in Lakehead's PLM databases.

Field: Bay City District - Ironwood PLM Office - Review of the Welder Qualification Record for Mr. Russell A. Paquette indicated that Mr. Paquette did not use the correct range for amperage for his 03/06/2000 test using LPL's Welding Procedure Specification #UF-28.

Engineering Drawing Review

195.402(c)(1) Maintenance and Normal Operation - Making construction records, maps, and operating history available for safe operation and maintenance.

G-Q16) How does the operator control engineering drawing revision, review, approval, and distribution?

R16) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q16) Headquarters	X			
Q16) Field	X			
R16) Headquarters	X			
R16) Field	X			

16) Comments: Lakehead's drafting department has responsibility for drawing development and distribution. The process for handling drawings are located in Lakehead's Engineering Procedures. Project Engineers have responsibility for making sure that as-builts are accurate (with regard to what was installed) and completed at the end of each construction project. Drafters go to the field to verify dimensional accuracy. It takes approximately 1 to 2 months to have changes placed on the alignment sheets and new alignment sheets are issued toward the end of the year, usually December or January. Field personnel use mark-ups in the interim. Flow diagrams are the first drawings to be updated and any changes that would effect the control center are submitted to the control center for incorporation into control center screens and operations.

195.404(a) Each operator shall maintain current maps and records of its pipeline systems.

Q17) Do the operator's "as-built" agree with field? Do the SCADA terminals get updates?

R17) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q17) Headquarters	X			
Q17) Field		X		
R17) Headquarters			X	
R17) Field		X		

17) Comments: Refer to comments under Q16.

Field: Superior District - Field drawings were reviewed against actual field facilities and were OK.

195.402(c)(1) Maintenance and Normal Operation - Making construction records, maps, and operating history available for safe operation and maintenance.

Q18) How are completed construction activities, such as facility modifications, communicated to the controller?

R18) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q18) Headquarters	X			
Q18) Field			X	
R18) Headquarters	X			
R18) Field			X	

18) Comments: Lakehead has a PLC coordinator and on any new projects, the coordinator works with the project engineer to see what is needed if PLC programming changes are required. Programs are stored at the headquarters level server along with hard copies. Field technicians have hard copies and storage disks. All PLC programs are protected with a "read only" feature. Refer to comments for Q16 for additional information.

Process Control and Flow Schematic Drawing Review

Differences between process control engineering drawings and pipeline facilities have resulted in incidents and abnormal operating conditions. We have found that physical changes made to facilities are sometimes not reflected in engineering drawing or SCADA displays. The company should have a procedure in place that ensures changes in the field are communicated to appropriate personnel and correspondence (i.e. maps, records and drawings) are corrected.

195.404(a) Each operator shall maintain current maps and records of its pipeline systems.

G-Q19) Do engineering, process control, and flow schematic drawings adequately depict current facilities and operations?

R19) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q19) Headquarters	X			
Q19) Field	X			
R19) Headquarters	X			
R19) Field	X			

19) Comments: Field: Superior and Bay City Districts - Field drawings were reviewed against actual field facilities and were OK.

Review of First Discovery Reports

First discovery reports are reports that may identify potential problems on, or in the vicinity of the pipeline, that could affect pipeline integrity and/or public safety. These reports could include any pipeline safety inspection and/or survey reports, landowner or general public reported concerns, patrol reports. Listed below are a few high impact examples.

195.416(e) External Corrosion Control - the operator shall examine exposed pipe for external corrosion.

195.416(i) External Corrosion Control - the operator shall clean, coat for the prevention of atmospheric corrosion

195.401(b) Operation and Maintenance - the operator shall correct any condition that could adversely affect the safe operation of its pipeline within a reasonable time.

G-Q20) Does the operator disseminate, monitor, and follow-up the information obtained from first discovery reports?

R20) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q20) Headquarters		X		
Q20) Field		X		
R20) Headquarters			X	
R20) Field	X			

20) Comments: Lakehead's procedures require modification to include first discovery reports from the public, employees, contractors and sources other than those that are reported directly to the control center.

Field: Superior and Bay City Districts - Discovery reports and follow up records were reviewed and were OK.

195.416(e) cont'd

G-Q21) Does the company follow-up and document discovered exposed spanning pipe in water and do they take fluctuating water levels into consideration?

R21) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q21) Headquarters	X			
Q21) Field			X	
R21) Headquarters			X	
R21) Field			X	

21) **Comments:** Whenever field personnel discover exposed spanning pipe that may require evaluation, then Engineering is notified. Engineering does an analysis (including evaluation of stresses) and prepares a plan of action for corrective measures needed. Exposed pipe is handled on a case-by-case basis and a formal list of all exposed pipe locations is not kept. A table of maximum allowable length between pipe supports is located in Book 3 of Lakehead's O & M manual. The table shows that the range of unsupported pipe lengths is 80 to 115 feet depending on pipe diameter and wall thickness.

195.408(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system, and (b) The communication system required by paragraph (a) of this section must, as a minimum, include means for: (1) Monitoring operational data as required by §195.402(c)(9);(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and (4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.

G-Q22) How does the operator follow-up and document public/landowner complaints concerning safety and integrity issues?

R22) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q22) Headquarters	X			
Q22) Field	X			
R22) Headquarters	X			
R22) Field	X			

22) **Comments:** Most complaints would go to Lakehead's 800 emergency number at the control center. These calls would be recorded on an incident information form. An initial assessment would be done to determine if an immediate shut-down is required. If there is a shut-down, it is recorded in LPL's "Facilities Management" (FACMAN) program. The first call would be to the police, if necessary. The second call would be to field personnel to respond to and investigate the called in report.

195.401(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under §195.402(a) of this subpart; and (b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

195.404(b) Each operator shall maintain for at least 3 years daily operating records that indicate-

(1) The discharge pressure at each pump station; and
(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

(c) Each operator shall maintain the following records for the periods specified;

(1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.
(2) The date, location, and description of each repair made to parts of the pipeline other than pipe shall be maintained for at least 1 year.
(3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

G-Q23) How does the operator follow-up and document integrity issues system-wide?

23) Comments: Lakehead has a "Pipeline Integrity" (PI) group which is responsible for the overall integrity management program. When internal inspection tool runs are made, results go to the PI group which does an analysis for data validity and defects that are of a critical nature. Priority is first given to anomalies considered to be of a critical nature. The PI group also prepares any dig list. The PI group communicates with field personnel and vendors on what is actually found versus what the tool run data reported. Historically, LPL has not used integration of CP and pig run data to analyze potential problem areas. However, LPL is in the initial stages of using an integration of data program. A close interval survey is done every 5 years an a rotating basis among the district areas.

Training

Operator errors result in pipeline incidents every year. We are trying to determine what processes operators have in place to address the training requirements and safety needs of the pipeline industry.

195.403 Training

G-Q24) Has the operator established and conducted a continuing training program to instruct operating and maintenance personnel?

R24) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q24) Headquarters	X			
Q24) Field	X			
R24) Headquarters	X			
R24) Field	X			

24) Comments: Initial training is per Performance Based Training (PBT). PBT has 3 levels of training for each position as follows - 1) performed the task; 2) assisted in performing the task and 3) received an explanation/demonstration of the task. PBT requires that the employee's supervisor sign off when a job/task is completed. LPL maintains a database for recording tasks, dates of performance and sign off dates.

195.403 Cont'd

Q25) Does the operator review, at intervals not exceeding 15 months, but at least once each calendar year, the performance of their personnel in meeting the objectives of the training program?

R25) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q25) Headquarters	X			
Q25) Field	X			
R25) Headquarters	X			
R25) Field	X			

25) Comments: LPL's training procedures include an annual performance review of personnel. A review is also done on the training topics to see how topics can be improved to meet training objectives.

195.509(a) Operators must have a written qualification program by April 27, 2001.

G-Q26) Has the operator developed a written qualification program?

R26) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q26) Headquarters	X			
Q26) Field			X	
R26) Headquarters	X			
R26) Field			X	

26) Comments: LPL's operator qualification program has been in development over the past 2 years. LPL now has a formal written OQ plan with an effective date of 4/27/01. The elements of the plan meet the criteria of the OQ regulation.

Corrosion Control

Corrosion is a major cause of accidents and disbonded coating is often the leading factor. A check of close interval surveys for depressed areas may reveal disbonded coating. Pipe segments adjacent to locations where corrosion is found could easily develop corrosion because it may be subject to the same conditions. Additional preventive measures should be taken in these areas such as bell hole examinations and smart pigging activities. Review locations where clock-spring repairs were made to identify pipe segments that are subject to active corrosion.

195.414 Cathodic Protection

195.416 External Corrosion Control

195.418 Internal Corrosion Control

G-Q27) Does the company maintain a comprehensive corrosion control program?

R27) Associated Records (annual survey, rectifiers)?

	Satisfactory	Needs Improvement	N/A	N/C
Q27) Headquarters	X			
Q27) Field	X			
R27) Headquarters			X	
R27) Field	X			

27) Comments: LPL maintains a comprehensive corrosion control program which covers both internal and external corrosion. There is one senior corrosion technician located at LPL's Chicago District office. This senior corrosion technician assists with corrosion issues on a company wide basis. Corrosion issues at the District level are handled by a corrosion technician based out of each District office. The actual surveys are done by a third party contractor and the District corrosion technician reviews the contractor's work to ensure compliance with company criteria and regulations. Program includes close interval surveys, CP interference tests with other companies, "on-off" surveys and recently includes sharing of information between the pipeline integrity group and the corrosion control group.

G-Q28) Best Practice: Industrial Standards - RP0169, NACE
Is the company's corrosion program under the direction of a qualified person? (List the qualifications in the comment field.)

28) Comments: Each district is responsible for and manages the corrosion control program within the district. The company has a Senior Corrosion person based at of Griffith, Kimberly Harris, who is available to assist with problems and questions on a system wide basis. Ms. Harris is a Certified Corrosion Technologist.

195.402 Procedural Manual for Operation, Maintenance, and Emergencies - the operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

G-Q29) Are corrosion control procedures in place and do they follow Part 195/NACE/industry standards?

R29) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q29) Headquarters	X			
Q29) Field	X			
R29) Headquarters			X	
R29) Field			X	

29) Comments: LPL's corrosion control program follows Part 195 and NACE standards. Corrosion control procedures are found in Book 3 of Lakehead's O & M manual. Refer to the comments for Q27 for additional information.

195.402 cont'd

195.414 cont'd

195.416 cont'd

195.418 cont'd

G-Q30) How is the gathered information reviewed and analyzed to identify problem areas?

R30) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q30) Headquarters	X			
Q30) Field	X			
R30) Headquarters	X			
R30) Field			X	

30) Comments: In the past, LPL has not integrated CP data with pipeline internal inspection data to identify problem areas, but this has recently changed as LPL's integrity management group seeks to improve the integrity program. Company experts meet to determine what the integrity program/plan should be. Many factors are considered in the plan and an Enbridge wide plan is developed. The integrity plans are developed as a system, but each line is individually evaluated.

195.401(b) Operation and Maintenance - the operator shall correct any condition that could adversely affect the safe operation of its pipeline within a reasonable time.

G-Q31) Under what conditions does the operator take prompt remedial action?

R31) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q31) Headquarters		X		
Q31) Field			X	
R31) Headquarters			X	
R31) Field			X	

31) Comments: Priority for prompt remedial action is given to problems that may indicate an imminent failure, would result in a immediate impact on the pipeline MOP or flow rate, would impact on public safety or would impact environmentally sensitive areas. Beta foils are used to determine internal corrosion problems, but LPL needs formal written procedures detailing how beta foils are used, criteria required and what the corrective process is when the beta foils due indicate a problem. The beta foil data is analyzed by a third party contractor. The pipeline integrity group uses internal inspection data to determine problem areas and corrective actions required. LPL has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of LPL's pipeline systems, especially with regard to corrosion control procedures and remedial actions taken. However, LPL has not formalized the process by inclusion of specific verbiage in LPL's O & M manual.

Q32) Best Practice:
What factors are considered in determining the need for and timing of pigging and close interval surveys?

32) Comments: Lakehead uses such factors as coating type, product type, leak history, pipe type, operation history, internal inspection history, defect history and seam weld type. Lakehead will begin using an overlay of high resolution tool runs to determine corrosion rates to determine future intervals for tool runs. Close interval surveys are done every 5 years.

Tanks

Inspection criteria relating to Tankage.

195.2 Definition - Breakout Tank means a tank used to (a) relieve surges in *hazardous liquid pipeline system* or (b) receive and store hazardous liquid transported by a pipeline for re-injection and continued transportation by pipeline.

G-Q33) Has the operator correctly identified/classified its tanks?

R33) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q33) Headquarters	X			
Q33) Field	X			
R33) Headquarters			X	
R33) Field			X	

33) Comments: Tanks identified as breakout tanks and OPS jurisdictional at Superior, Clearbrook, Stockbridge and Griffith. The NGL bullet tanks at Superior are used strictly for surge pressure relief. Tanks are considered to be dual jurisdictional between OPS and the ICC at the Hartsdale Terminal. The Hartsdale tanks are storage tanks that can be used for "lease".

195.428(b) Over pressure safety devices - In case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

G-Q34) Does the operator ensure relief valves are tested?

R34) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q34) Headquarters	X			
Q34) Field	X			
R34) Headquarters			X	
R34) Field	X			

34) Comments: There are relief valves on the NGL bullet storage tanks at Superior. These relief valves are tested every 5 years.

195.432 Breakout tanks - Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each breakout tank (including atmospheric and pressure tanks).

G-Q35) Has the operator conducted the appropriate inspections? Does the operator use available industry codes and standards to uniformly establish maintenance and repair inspection criteria for the breakout tanks?

R35) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q35) Headquarters		X		
Q35) Field		X		
R35) Headquarters			X	
R35) Field	X			

35) Comments: Procedures for tank inspections are located in Book 3, Section 09-02-02 of Lakehead's O & M manual. LPL's procedures need revision to include verbiage on what the corrective action process is if problems are found during any breakout tank inspection. LPL should implement a method to address conclusions and recommendations made during a tank inspection, and the status of corrective actions. The procedures also need specific references to industry standards API 2003 and API 2510. The procedures need specific verbiage on what items to look for during tank inspections. LPL uses API653 inspection criteria. The tank floors are given a 100% MFL scan. The inside seam on the bottom of the tank is given a 100% vacuum box test. LPL does not have a centralized tank inspection program run from headquarters. The headquarters tank personnel act in an advisory role to the Districts. The Districts maintain the inspection records, request funds for inspections and decide on threshold intervals for tank inspections.

Field: Bay City Records - Tank inspection records for the Stockbridge, MI station were missing for the year 2000.

G-36) Best Practice:
Are the breakout tanks equipped with high level alarms?

36) Comments: Lakehead's breakout tanks have two stages of high level alarms set at "High" and at "High - High". The "High - High" alarm is independent of the "High" alarm. The "High" level is via a tape type floating gauging system. The tape gauging system also includes a gauge near the bottom of each tank which can be used for a visual indication of the tank's level.

Valves

It is important that isolation valves be in good working order and accessible when needed.

195.116 Valves

G-Q37) Has each valve been properly designed, marked, and tested?

R37) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q37) Headquarters	X			
Q37) Field	X			
R37) Headquarters			X	
R37) Field			X	

37) Comments: Specifications for Lakehead's valves are located in Lakehead's Engineering Standard D06-105. Engineering sets the specifications for all valves. Lakehead orders valves meeting API6D criteria. The valves are full open port, rising stem valves. All mainline valves are ordered with a open/close indicator.

195.260 Valve Locations - A valve must be installed at each of the following locations: on the suction and discharge end of a pump station; on each line entering or leaving a breakout tank area; along the pipeline that will minimize damage or pollution from accidental discharge; on each lateral takeoff from the trunk line; on each side of a water crossing that is more than 100 feet wide at high-water mark; and on each side of a reservoir holding water for human consumption.

G-Q38) Are mainline valves properly identified and located?

R38) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q38) Headquarters	X			
Q38) Field	X			
R38) Headquarters			X	
R38) Field			X	

38) Comments: Lakehead considers any valve that blocks, controls or isolates mainline flow is a mainline valve. A risk management type process is used to identify where valves should be located. Priority consideration is given to high risk areas such as wetlands. Mainline valve lists are maintained in each district.

195.420(a) Valve Maintenance - the operator shall maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.

G-Q39) Does the operator maintain each valve that sees mainline pressure and flow in good working order?

R39) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q39) Headquarters	X			
Q39) Field		X		
R39) Headquarters			X	
R39) Field			X	

39) Comments: Valve maintenance procedures are located in Book 3, Section 03-02-01 of Lakehead's O & M manual.

Field: Bay City District - A open/close indicator rod on a mainline valve was inoperable at the following location:

(a) M/L Valve at MP1238.153 (Wolf Lake Road).

195.420(b) Valve Maintenance - the operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

G-Q40) Does the operator inspect each mainline valve on a bi-annual 7 ½ month basis to determine that their valves are functioning properly?

R40) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q40) Headquarters		X		
Q40) Field	X			
R40) Headquarters			X	
R40) Field	X			

40) Comments: LPL's procedures on valve inspections are confusing in that the procedures could be interpreted to mean that valve inspections are only done once per calendar year, when in fact, LPL inspects valves twice per calendar year per code requirements. The procedures need clarification so that there is no doubt that valves are to be inspected twice per calendar year. LPL did have one valve inspection interval that was exceeded due to flooding and it was suggested to LPL that comments regarding unusual conditions affecting inspections should be added to the valve inspection record.

Field: Superior and Bay City Districts - Field check of records verified that valve inspections are done twice per calendar year.

195.420(c) Valve Maintenance - the operator shall provide protection for each valve from unauthorized operation and from vandalism.

G-Q41) Does the operator protect their valves from vandalism?

R41) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q41) Headquarters	X			
Q41) Field	X			
R41) Headquarters			X	
R41) Field			X	

41) Comments: Mainline valves are secured with a chain and padlock to prevent unauthorized operation. Steel pipe guard posts are installed around each valve that has the potential to be damaged from mowing activities, farming operations, land maintenance activities, street/highway/road maintenance activities and/or vehicular traffic.

Field: Superior and Bay City Districts - Field inspection of random valve locations verified that valves are properly protected from vandalism.

195.404(c)(3) Maps and Records - Each operator shall maintain a record of their inspection of mainline valves for two years.

G-Q42) Does the operator maintain proper records for mainline valves?

R42) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q42) Headquarters			X	
Q42) Field	X			
R42) Headquarters			X	
R42) Field	X			

42) Comments: Records for mainline valves are kept in each District office.

Field: Superior and Bay City Districts - Mainline valve records for this District were OK.

G-Q43) Best Practice:
Are valves located to provide quick response for environmentally sensitive areas such as drinking water sources, national parks, etc.?

43) Comments: For valve locations, priority is given to such areas as wetlands, high populated areas and major river crossings. When locations for valves are considered, Lakehead looks at such parameters as access for vehicles, availability of electric power and security measures required. In the event of a leak detection, all valves between the two adjacent stations would be closed. Lakehead's remotely operated valves have an average closure time of approximately 3 to 6 minutes. Lakehead does not have a overall conscious effort to identify environmentally sensitive areas to install valves, but Lakehead does have topographic maps with color coded sensitivity ratings which are used for response activity and emergency planning.

G-Q44) Best Practice:
Are there any locations where special features, such as valve stem extension in flood plains, had to be incorporated because of difficulty in complying with the above? Are there any automatic or remotely controlled valves?

44) Comments: Lakehead has used valve extensions on valves where appropriate. Some of Lakehead's more "critical" mainline valves, such as "sectionalizing" valves, are remotely controlled. In the event of a power failure, the remotely controlled valves stay open. Typically, Lakehead does not monitor the pressure at the remotely controlled valves. Some other strategic valves, such as stream/river crossings are a mixture of remotely operated and manually operated.

Patrol Program

An effective patrol program will combine information throughout the company to prevent damage to the pipeline and detect damage that has already occurred. Companies are encouraged to correlate information from a variety of sources such as comparing patrolling records with internal inspection data. Communication and areas of responsibility between patrol pilots and the personnel who follow-up and track the reports should be clearly defined so that both parties understand their role in preventing outside force damage.

195.402 Procedure Manual for Operations, Maintenance and Emergencies.

G-Q45) Does the operator have an adequate patrolling program ?

R45) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q45) Headquarters	X			
Q45) Field		X		
R45) Headquarters	X			
R45) Field	X			

45) Comments: Lakehead does aerial patrols every other week. Procedures for patrolling are located in Book 3, Section 03-02-01 of Lakehead's O & M manual. Aerial discoveries are reported on a "Daily Patrol Report" and are completed in electronic format. Field personnel respond to the reports and enter confirmation of actions taken electronically on company's computer. Lakehead uses it's own pilot for aerial patrol and helicopters are the main aircraft type used. If the helicopters are in for service, then Lakehead uses a third party aerial service out of Bemidji, MN. In the event of special conditions, such as flooding or sections that may be under a pressure restriction, the patrol frequency is increased. When a new pilot is hired, the new pilot will fly with the previous pilot for at least 2 weeks.

Field: Bay City District - Field inspection revealed that LPL's right-of-way needs clearing at the following locations:

(b) MP1164.60 - west side
(c) MP1238.153
(d) MP1247.89
(e) MP1260.166 - west side
(f) MP1280.307 - west side
(g) MP1387.577 - east side
(h) MP1429.301 - west side
(i) MP1439.71 - Black River crossing (both sides)
(j) MP1460.187
(k) MP1465.50 - east side

Line Markers and Damage Prevention (Locating and Marking Pipelines)

It is critical that personnel who locate buried pipe in the course of their work are qualified and competent. Personnel performing this work may be operator or contract service company employees (line locate company, corrosion survey company, pipeline surveyors, etc.).

195.410(a) Line Markers - each operator shall place and maintain line markers over each buried pipeline.

G-Q46) Are markers located at public road crossing, railroad crossings, and in sufficient number along the remainder of each buried line?

R46) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q46) Headquarters	X			
Q46) Field		X		
R46) Headquarters			X	
R46) Field			X	

46) Comments: Lakehead's policy is to place markers at road / railroad crossings, water crossings and other significant areas accessible to the public. At valve locations, LPL uses signs or markers or a combination of both.

Field: Superior District - LPL's markers and signs displayed an incorrect company contact number or was missing a contact number at the following locations:

(a) M/L Valve at MP1105.98
(b) M/L Valve at MP1115.55
(c) M/L Valve at MP1127.69.

Field: Bay City District - LPL's markers and signs displayed an incorrect company contact number or was missing a contact number at the following locations:

(a) M/L Valve at MP1173.20
(b) M/L Valve at MP1183.78
(c) M/L Valve at MP1212.18
(d) MP1222.048 (markers on each side of road)
(e) MP1238.153 (markers on each side of road)
(f) M/L Valve at MP1299.72.

Field: Bay City District - Signs or markers were missing at the following locations:

(g) M/L Valve at MP1307.35
(h) M/L Valve at MP1343.70
(i) MP 1393.759 Indian River - East Side
(j) M/L Valve at MP1396.39.

195.402(c)(13) Procedural manual for operations, maintenance, and emergencies - Maintenance and normal operations - the manual must include procedures for periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

195.442(a) Damage prevention program - if the operator does not participate in a public service program, such as a one-call system, then the operator of a buried pipeline must carry out a written program to prevent damage to that pipeline from excavation activities.

G-Q47) Does the operator participate in a public service program? If not, does the operator evaluate their damage prevention procedures and take corrective action where deficiencies are found?

R47) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q47) Headquarters	X			
Q47) Field	X			
R47) Headquarters			X	
R47) Field	X			

47) Comments: The public service programs that Lakehead participates in are 1) the One-Call program and 2) the Common Ground Alliance program. A LPL representative chairs the API Damage Prevention Committee. LPL is in the process of preparing a table which is a comparison of the provisions from all the state One-Call programs that affect LPL. LPL would like to "push" the states toward similarity in state One-Call provisions. One-Calls are routed to LPL's headquarters, headquarters determines which District office is involved and forwards the One-Call requests to the appropriate District. Lakehead has a PC computer system which is solely dedicated to managing One-Call activities. One-Call records are located at various LPL pipeline maintenance (PLM) offices. There are 12 locations through out LPL's system that respond to One-Call reports.

195.442(c) Damage prevention program - the operator must identify, on a current basis, persons who normally engage in excavation activities in the area in which the pipeline is located; notify the public and persons who normally engage in excavation activities of the damage prevention program; provide a means of receiving and recording notification of planned excavation activities; provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings; and provide inspection of excavation activities, if the operator believes the pipeline could be damaged by excavation activities.

195.442(c)(3) Damage prevention program - if the operator participates in a public service program, such as a qualified one-call system, then the operator must: provide a means of receiving and recording notification of planned excavation activities.

G-Q48) Does the operator have an adequate damage prevention program?

R48) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q48) Headquarters	X			
Q48) Field	X			
R48) Headquarters			X	
R48) Field	X			

48) Comments: One-Calls are usually handled out of various LPL pipeline maintenance (PLM) offices within each District. LPL relies on the One-Call program to maintain a list of excavators. Whenever LPL receives a request from a third party to cross LPL's lines, LPL tries to obtain a formal written crossing agreement which details the parameters that LPL requires for a crossing.

G-Q49) Best Practice: NPRM Qualification of Pipeline Personnel
Are trained/qualified personnel used for pipeline locating & marking?

49) Comments: Lakehead uses only trained company employees to locate and mark lines. Line locating and marking is one of the covered tasks in Lakehead's operator qualification plan. Lakehead has 3 crossing coordinators who have attended the one week course at Staking University in Marysville, MI. These crossing coordinators then conduct field training of other LPL personnel. Vendors go to Lakehead field locations and train personnel on the use of specific line locating equipment.

Liaison with Construction Project and Land-Use Officials (Public Education)

Encroachment around pipelines poses serious safety risks as third parties excavate in proximity to buried pipelines. A strong damage prevention program will provide advance notification of construction plans near the pipeline and will establish communication with the people involved in the project.

195.440 Public Education - each operator shall establish a continuing educational program to enable the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator or the fire, police, or other public officials.

G-Q50) How does the operator implement its continuing education program?

R50) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q50) Headquarters	X			
Q50) Field	X			
R50) Headquarters			X	
R50) Field	X			

50) Comments: Lakehead's public awareness program is located in Book 1, Sections 04-01-01 and 04-02-01 of Lakehead's O & M manual. After identifying pubic officials that may need notifications, contact is made using mailings, face-to-face meetings and group meetings. Contact information is updated annually. General public awareness is through mailings of brochures, calendars and newspaper advertisements. LPL uses a API public awareness brochure as a multi-language mailing for landowners/tenants. Mailings to landowners/tenants is done annually. Every 3 years LPL tries for face-to-face meetings with groups and individuals who are located outside of LPL's right-of-way boundaries.

G-51) Best Practice:
Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

51) Comments: Lakehead has recently added mailings to planning and zoning directors as part of LPL's program. Presentations are for county officials such as county clerks and zoning personnel.

G-Q52) Best Practice:
Does the operator's damage prevention program include pro-active liaison with local school officials, where the pipeline traverses or is adjacent to, school property?

52) Comments: Lakehead does not have a pro-active company wide program for liaison with school officials. The district level offices have some contact with schools located along LPL's right-of-way. LPL's presentation to schools is focused on school staff members and school administrative personnel.

G-Q53) Best Practice:
Does the operator have a liaison program that includes local developers and construction project officials?

53) Comments: Refer to comments for Q51. LPL does not have a formal program for liaison with land developers, real estate companies or other private land use managers.

G-Q54) Best Practice:
Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

54) Comments: LPL is a member of the Common Ground Alliance. LPL has one member of the Common Ground committee. The Common Ground study was reviewed by approximately 6 Lakehead individuals.

G-Q55) Best Practice:
Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

55) Comments: Lakehead compared LPL's plan to the Common Ground practices and recommendations were forwarded to the District Managers.

G-Q56) Best Practice:
Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

56) Comments: Lakehead has modified their public awareness program based on some of the practices in the Common Ground study. Lakehead now sends two people out to audit One-Call centers. The modifications done to Lakehead's damage prevention program as a result of the Common Ground Study were minor in nature.

G-Q57) Best Practice:
Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

57) Comments: Lakehead incorporates the 4 or 5 points on digging/damage prevention in the study. Lakehead looks at damage prevention as a whole process that goes beyond just "call before digging". LPL feels that "call before digging" should include all steps (call in, wait the required time interval, pay close attention to the pipeline company's markers, use safe procedures while digging, etc.) Lakehead has modified their internet website to provide better public awareness.

Field Verification of Facility Response Plan Information		Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number <u>**865 District 3, 866 District 4, 867 District 5, 868 District 7**</u> Approval Date <u>**2/17/95 Renewal pending via DOT letter dated 3/20/01.**</u> [See Guidance OPA-1]	X		
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			X
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]	X		

OPA Inspection Guidance

<u>OPA-1</u> - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

<u>OPA-2</u> - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

<u>OPA-3</u> - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

<u>OPA-4</u> - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

<u>OPA-5</u> - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead P/L **Date(s):** 5/14 - 5/18

Unit: Superior / Escanaba CRUDE SYSTEM 2

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 1105.98		-1.105	off			Several rectifiers were turned
m/L Valve						off during the field inspection
						time frame for one of the
MP 1115.55		-1.038	off			following reasons:
m/L valve		-1.588	on			(1) Great Lakes had about
						20 miles of bad data
MP 1124 TS		-0.988	off			on their lines and was
						re-surveying and needed
MP 1129.69		-0.941	off			to have LPL have
m/L Valve						LPL's rectifiers off.
MP 1137.32						(2) LPL was conducting
INO STATION						a static survey
Valve-incoming		-0.815	off			in certain areas.
Valve 5-SDV-1		-0.683	off			
MP 1146.61		-0.946	off			
m/L Valve						
MP 1150.7		-1.160	-0.640	off		
Hwy2 & #63						
MP 1158 TS		-1.342	off			
		-1.916	on			
MP 1159.47		-1.166	off			
m/L Valve						
MP 1164.6 TS		-1.447	off			
MP 1169.2 TS		-1.514	off			
MP 1173.20		-0.490		meets 100mV shift criteria		
MP 1183.58						
SAXSON STATION						
Valve 5-SSV-1		-1.269	on			
Valve 5-USV-1		-1.685	on			
Valve - Sta. Discharge		-2.054	on			
Sta. Rectifier				44.0	16.3	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead P/L

Date(s): 5/14 - 5/18

Unit: Superior / Escanaba CRUDE SYSTEM 2

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 1189.21		-1.558				See notes on page 1
MP 1191.00		-2.197				
M/L Valve						
Rectifier				26.22	1.40	
MP 1197.04		-1.258				
m/L Valve						
MP 1202.56						
m/L valve		-1.866				
Rectifier				16.67	6.90	
MP 1212.18		-1.076				
m/L valve						
MP 1222.048		-1.363				
MP 1226.18						
GOGEBIC STATION						
Pipe		-4.910				
PD area		-2.030	pipe			
		-1.997	shell			
Unit 5-U-2	Dish.	-1.073				
Rectifier				57.3	16.44	
MP 1238.153		-2.080				
MP 1247.89		-1.091				
M/L valve						
MP 1260.166		-2.674				
MP 1271.85						
IRON RIVER STATION						
Valve 5-USV-31		-2.385				
Valve 5-SSV-1		-3.092				
Valve 1272.27-5-V		-1.449				
Trap		-3.380				
Rectifier				47.8	9.9	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead P/L

Date(s): 5/14 - 5/18

Unit: Superior / Escanaba CRUDE SYSTEM 2

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 1280.307		-2.540				See notes on page 1
MP 1288.0		-5.150				
Rectifier				23.25	21.90	
MP 1290.094		-1.758	-1.107			
MP 1299.72		-2.120				
m/L Valve						
MP 1307.35		-2.293				
m/L Valve						
MP 1318.54		-2.250				
m/L Valve						
MP 1329.209						
Rectifier				24.72	3.1	
MP 1334.375		-0.727	off	meets	100mV shift	criteria
m/L Valve						
MP 1343.70		-0.832	off			
m/L Valve						
MP 1352.0						
Rectifier				16.45	6.42	
MP 1356.63						
RAPID RIVER STATION						
Valve - discharge		-0.844	off			
Valve - suction		-0.920	off			
Rectifier				33.74	7.9	
MP 1369.62						
TS		-0.948	-0.414	off		
Rectifier				24.89	10.14	
MP 1373.13						
M/L Valve		-0.743	off			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead P/L

Date(s): 5/14 - 5/18

Unit: Superior / Escanaba CRUDE SYSTEM 2

Line & Location	Line Size, in.	Field Readings CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1381.532		-0.832	-0.500	off		See notes on page 1.
MP 1387.577		-0.925	-0.614	off		
MP 1392.33						
MANISTIQUE STATION						
Valve 1392.37-5-V		-0.797	off			
Valve 5-SDV-1		-0.905	off			
Valve 5-USV-21		-0.593	off			
Rectifier				23.93	6.24	
MP 1396.39		-0.690	off			
M/L Valve						
MP 1396.84						
Rectifier A				16.45	4.60	
MP 1406.45		-0.733	off			
M/L Valve						
TS		-0.721	-0.481	off		
Rectifier				36.09	6.1	
MP 1411.983		-0.747	-0.599	off		
MP 1422.82						
GOULD CITY STATION						
Valve 5-SSV-1		-0.780	off			
Valve 5-UDV-31		-0.720	off			
Rectifier				28.12	7.7	
MP 1429.301						
TS		-1.013	-0.852			
Rectifier				27.42	13.14	
MP 1439.71		-0.723	off			
M/L Valve						

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead P/L

Date(s): 5/14 - 5/18

Unit: Superior / Escanaba CRUDE SYSTEM 2

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 1441.43						See notes on page 1
NAUBINWAY STATION						
Sump Tank		-0.526	off			
Valve 5-CSV-22		-0.596	off			
Valve 1441.48-5-BV		-0.657	off			
Rectifier A (Station)				13.2	14.36	
Rectifier B (pipeline)				61.3	7.80	
MP 1450.979						
TS		-0.644	-0.585	off		
Rectifier				34.34	3.55	
MP 1460.187		-0.987	off			
MP 1465.50		-0.670	off			
M/L Valve						
MP 1475.63						
Straits of Mackinaw						
Pipe @ densitometer		-1.013				
Trap		-1.047				
MP 1479.55						
Mackinaw STATION						
Trap - East		-3.020				
Trap - West		-6.250				
Trap - Outgoing		-4.450				
Sump		-7.420				
MP 1484.664		-1.381	-0.544			
MP 1491.706		-1.846	-0.496			
MP 1496.636		-1.533				
M/L Valve						
MP 1498.807						
Rectifier				11.08	12.0	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead P/L
Date(s): 5/14 - 5/18
Unit: Superior / Escanaba CRUDE SYSTEM 2

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 1505.096		-1.255				See notes on page 1
MP 1507.044						
M/L Valve N. side of Indian River		-1.261				
MP 1508.88		-0.938				
M/L Valve S. side of Indian River						
MP 1514.851						
INDIAN RIVER STATION						
Sump		-2.370				
Piping - Control Bldg.		-2.958				
Valve 5-UDV-31		-2.251				
Valve 1514.91-5-BV		-2.002				
Rectifier				11.02	4.2	

U.S. Department
of Transportation

Research and
Special Programs
Administration

Inspection Summary

Central Region Office

Office of Pipeline Safety

To: Region Director JH

Date: 4/5/02

From: Phil Archuletta, Staff Engineer PA.

Company Inspected: LAKEHEAD PIPE LINE CO INC

Operator: LAKEHEAD PIPE LINE CO INC

Type of Service: Interstate Liquid

Inter-Regional System:	System Description	Inspection I.D.
CRUDE SYSTEM 1	Various size lines from Canada/North Dakota border to MN/WI border, (in the CE region the system includes Unit #132: Superior, Unit #308 All Lines in MN & Unit #1612 North Dakota)	93252 (Headquarters) 91794 (Field) 91730 (Field)

Dates of Inspection: 5/7/01 - 5/12/01 (Headquarters); 8/27/01 - 8/31/01 (records & field); 9/21/01 (MNOPS concluded their records review)

Location: Duluth, MN (records); States of Minnesota and North Dakota (field facilities)

Facilities Inspected: Phil Archuletta and David Barrett from CE OPS and Brian Pierzina and Boyd Haugrose from MNOPS conducted a CE-regional system inspection of Lakehead Pipeline Company's Crude System #1. The inspection was conducted using the "New High Impact Form (NHIF)" inspection form. All documents and records requested were presented and were satisfactory with the exception of items noted below under "Deficiencies Found."

Lakehead Pipe Line's facilities for this unit consist of the following:

- Approx. 323 miles of 18" from the US/Canada border to Superior, WI
- Approx. 136 miles of 20" from the US/Canada border to Clearbrook, MN
- Approx. 324 miles of 26" from the US/Canada border to Superior, WI
- Approx. 324 miles of 34" from the US/Canada border to Superior, WI
- Approx. 136 miles of 36" & 48" from the US/Canada border to Clearbrook, MN

- 12 Pump stations located at Gowan, Floodwood, Blackberry, Deep River, North Cass Lake, Cass Lake, Wilton, Clearbrook, Plummer, Viking, Donaldson and Joliette
- Breakout tanks located at Clearbrook, MN.

The actual physical facilities inspected included all of the facilities listed in the preceding paragraph.

A number of stops were made at valve settings, pump stations and points along the pipeline segments where C/P readings could be taken.

Persons Interviewed:

Refer to page 1 of the attached "High Impact" form for a listing of persons interviewed.

Deficiencies Found:

Lakehead Pipe Line's O&M Manuals were not evaluated. This operator is scheduled in 2001 for an inspection of several systems and the O&M Manuals will be reviewed at the operator's headquarters in conjunction with the headquarters portion of the system inspections.

A review of Lakehead Pipe Line's records and field facilities identified the following deficiency:

Headquarters Issues:

A. Notice of Amendment Items:

1. § 195.401 (b) General requirements.

Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(a) LPL procedures need revision to include verbiage about including first discovery reports from all sources such as the public, employees, contractors, etc. and not just reports made to LPL's Control Center.

(b) LPL has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of LPL's pipeline systems, especially with regard to internal corrosion control procedures and remedial actions taken. However, LPL has not formalized the process by inclusion of specific verbiage in LPL's O & M manual.

2. § 195.402 Procedural manual for operations, maintenance, and emergencies.

Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

LPL procedures need revision to include verbiage about what LPL does for analysis and investigation of abnormal operating events to prevent re-occurrences of the events.

3. § 195.405 Protection against ignitions and safe access/egress involving floating roofs.

After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API Recommended Practice 2003, unless the operator notes in the procedural manual (§195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2003 is not necessary for the safety of a particular breakout tank.

LPL procedures need specific reference to industry standard API 2003.

4. § 195.420 Valve maintenance.

Each operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

LPL's procedures on valve inspections are confusing in that the procedures could be interpreted to mean that valve inspections are only done once per calendar year, when in fact, LPL inspects valves twice per calendar year per code requirements. The procedures need clarification so that there is no doubt that valves are to be inspected twice per calendar year. LPL did have one valve inspection interval that was exceeded due to flooding and it was suggested to LPL that comments regarding unusual conditions affecting inspections should be added to the valve inspection record.

5. § 195.432 Breakout tanks.

Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks. LPL procedures need revision to include verbiage on what the corrective action process is if problems are found during any breakout tank inspection. LPL should implement a method to address conclusions and recommendations made during a tank inspection, and the status of corrective actions.

.432(b) LPL procedures need specific verbiage on what items to look for during tank inspections as found in Section 4 of API 653.

.432(c) LPL needs procedures to inspect breakout tanks built to API 2510 according to Sec. 6 of API 510.

Field Issues:

During the federal portion of the field inspection, it was discovered that some signs displayed a telephone number which when called should have automatically forwarded the call to LPL's main Control Center. However, at the time of the inspection, the calls were not being automatically forwarded as intended. LPL investigated the problem and the situation has been corrected so that all calls are now forwarded to LPL's main Control Center. Since LPL has now had a merger/re-organization, LPL (now Enbridge Energy Partners, Inc.) will be replacing all signs along their ROW with new signs displaying one appropriate contact number.

MNOPS reported that during their field inspection, low cathodic protection potentials were identified at MP 949.9, which is referred to as the Ferris Valve site. At the time of the concluding record review by MNOPS, which was on 9/21/01, LPL personnel reported that 7 valves had instant off potentials which ranged from -0.743v to -0.921v. The depolarized potentials ranged from -0.617v to -0.723v, establishing compliance with the 100 mV polarization decay criterion, and therefore this is not considered a deficiency.

MNOPS also reported that there appeared to be some difficulties maintaining P/S potentials near the storage tanks at Clearbrook for the past 3 months. It was believed to be due to equipment failure. Further testing parameters were decided upon. It was decided to shut down the rectifiers for a period of 1 week in an attempt to find a base line. MNOPS reports that Mears (corrosion contractor) in conjunction with the LPL corrosion technician, have done the proper testing and made the appropriate corrections and have the CP system at the tanks operating within code requirements and the NACE recommended practices. No additional action is required.

Conclusions/Recommendations:

Lakehead Pipeline has submitted documentation regarding action taken on the following items under paragraph A (copies of documentation are attached):

Item 1.(a) - Copy of intended revision (2 sheets) to Procedure"Notification of Safety Concern". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item.

Item 1.(b) - Copy of intended revision to Procedure 08-02-01, "Corrosion Control"; page 3 of 9 - "Monitoring". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 2. - Copy of intended revision to Procedure "Abnormal Operation Procedure Review Process". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 3. - Copy of intended revision to Procedure 09-01-01, "Overview of Tank Maintenance"; page 2 of 3. LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 4. - Copy of intended revision to Procedure 03-02-01, "Right-Of-Way Inspections"; page 5 of 5 - "Valve Inspections". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 5. [for .432(b)] - Copy of intended revision to Procedure 09-02-02, "Tank Inspections"; page 2 of 7 - "Records - Routine Inspections - Monthly". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 5. [for .432(c)] - Copy of intended revision to Procedure 09-02-02, "Tank Inspections"; page 1 of 7 - "Requirements - Inspection Frequency". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

TO: NORI 218.725.0405

ENBRIDGE Jim K Huber on 05/18/2001 01:53 PM

To: John W Haycs/IPL@IPL, Brad Shamla/IPL@IPL, David W Bryson/IPL@IPL, Mel Wyness/IPL@IPL, Allan D Baumgartner/IPL@IPL, Ian C Melligan/IPL@IPL
cc: Janet L Huggett/IPL@IPL
Subject: Proposed wording for Notification of Safety Concerns

As a line item noted by the DOT Audit, we may be deficient in addressing miscellaneous safety concerns called in by the public (this may include washed out pipe, unauthorized activity on the pipeline, etc.

The following is a draft procedure for the Database:

Notification of Safety Concern

When notified of a concern of a potential unsafe or hazardous condition:

1. Continue to operate the pipeline
2. Contact *the nearest station* on-call personnel immediately
3. Complete Incident Receiving Report Form

To address this concern, I propose we add the following warning to the Incident Information Form, p 3, Hazard Warning (to caller):

" We operate high pressure petroleum pipelines in your vicinity. It appears from your description and from observations of our control system, there is no immediate hazard from our pipelines. However, as a precautionary measure, we will dispatch company personnel to investigate the situation."

I also propose we add the following information to the Incident Information Form, p 4, Immediate Steps:

Company Personnel notified: ______________________ Time:__________
Company Personnel providing "All Clear": ______________________ Time:__________

Description of Follow Up Required (CCO Supervisor):____

Your feedback will be greatly appreciated. Please let me know what you think.

ENBRIDGE Jim K Huber on 05/18/2001 12:48 PM

To: Ian C Melligan/IPL@IPL, Janet L Huggett/IPL@IPL
cc:
Subject: Re: Notification of Safety Concern

195.401(b)
Q.20

Ian C Melligan

Next Prev Back

Notification of Safety Concern

When notified of a concern of a potential unsafe or hazardous condition: — popup

1. Continue to operate the pipeline
2. Contact *the nearest station* on-call personnel immediately — hot link
3. Complete Incident Receiving Report Form

Doug * *Note: Incident Report Receiving Form will be modified to include space for potential or unsafe conditions on the pipeline which will spawn follow up action by the Company.*

This form will be extensively revised to record:
- notification and/or all clear report (who, when)
- false alarm, safe condition & followup requirements
- response to caller

includes but is not limited to:
- unauthorized personnel on ROW or in facility
- exposed pipe
- station strobe light or horn sounding
- construction activity

Pipeline Integrity must recommend a prevention and maintenance program for internal corrosion by:

- determining treatment needs, concentrations and application methods
- selecting suitable chemical properties
- selecting appropriate in-line tools, if required
- selecting treatment locations

NOTE: Past performance and present day monitoring of inhibitor effectiveness continually affect these decisions.

195.401(b)

Q.31

Monitoring

Take beta foil readings at least 10 times per year with intervals not exceeding six weeks; however, make every effort to take readings once per month.

Further description of remedial action resulting from discovery of internal corrosion (i.e., beta foil readings) to be added here (DOT HQ Audit May 9/01). 195.401 (b)

NOTE: During cleaning and/or inhibitor injections, Pipeline Integrity may increase the frequency of beta foil readings.

NOTE: For more information on the company's beta foil and corrosion inhibitor plan, contact Pipeline Integrity.

Records

Excavation Inspection and/or Repair Report

Use the Excavation Inspection and/or Repair Report (CAN), or the Corrosion Inspection Report in the PLM Activity Report database (USA), to document both "as found" and "as left" conditions of exposed mainline or station piping during excavations.

USA

Distribute the Corrosion Inspection Report as follows:

1. Electronic original retained in Lotus Notes database.
2. Hard copy printed and filed at district/area office.
3. Hard copy printed and filed at Engineering.

USA

District office must retain Corrosion Inspection Reports for a minimum of two years.

ENBRIDGE Jim K Huber on 05/18/2001 12:42 PM

195.402(d)(5)
Q.7

To: Ian C Melligan/IPL@IPL, Janet L Huggett/IPL@IPL
cc:
Subject: Re: Abnormal Operation Procedure Review Process

Changes to the procedure as noted.

Ian C Melligan

Abnormal Operation Procedure Review ~~Process~~

~~At any time~~ After an initiated response of an Emergency Procedure *or abnormal operation* occurs:

1. *Within 24 hours* perform an initial procedure review to determine effectiveness of the procedure

   The initial procedure review shall include the following personnel:

   - Control Centre Coordinator on-shift during abnormal operation
   - Control Centre Operator on-shift during abnormal operation

2. If ~~review determines that~~ the procedure requires modification, notify ~~document and acquire approval from~~ Supervisor
3. Supervisor will initiate procedure change
4. Procedure will be modified and personnel shall be informed of change

Doug * *NOTE: CCO will add hot links which will activate this page to all procedures in this database descibing action during Emergency or abnormal operation .*

195.420(b)
Q.40

USA

Valve Inspection

Mainline valves, including remotely operated valves, must be inspected according to Maximo MP107 and MP256 at least twice during each calendar year at intervals not to exceed 7½ months.

In addition to the above, at least ~~once~~ twice each year the remote operation (i.e., open and close from control center) of remotely operated mainline valves must be verified according to Maximo MP179.

USA

Overpressure Safety Devices

Devices that limit, regulate and/or control maximum operating pressure must be inspected, tested or calibrated regularly according to Maximo:

- EP244 for pressure relief valves
- EP268 for pressure transmitters
- EP269 for pressure switches
- ET313 for OQT pressure allowable setpoints
- MP251 for pressure relief valves in crude service
- MP255 for pressure relief valves in NGL service
- MP290 for OQT pressure control valve system
- MP251 for OQT relief valve inspection and testing

Engineering, in cooperation with Operations employees, is responsible for determining if any device becomes inadequate in capacity and/or reliability for its intended purpose, and for ensuring the device is upgraded or replaced.

Records

CAN

Aerial Patrol Reports

Patrol pilots must document aerial inspections in the Aerial Patrol Report database. The report summarizes inspection dates and any abnormal conditions observed. Aerial Patrol Reports are permanently retained in the database and may be filed and at the regional office responsible for the area covered in the report.

NOTE: For Enbridge Pipelines (NW) Inc, the Aerial Patrol Report database is in the Lotus Notes NW Forum.

- D04-102, Painting, Coating and Lining
- D05-101, Berm, Containment
- D05-201, Foundation, Oil Storage Tank
- D05-401, Platforms, Stairs and Ladders
- D06-102, Piping Design, Station and Terminal
- D08-101, Oil Storage Tank
- D08-102, Oil Storage Tank, Roof
- D08-103, Oil Storage Tank, Accessories

Operating & Maintenance Procedures:

- Book 1: General Reference
- Book 2: Safety
- Book 4: Welding

Emergency Response Plan (ERP)
Waste Management Plan

Industry

American Petroleum Institute (API):

- API Guide for Inspection of Refinery Equipment, Chapter 13, Atmospheric and Low Pressure Storage Tanks
- API 650, Welded Steel Tanks for Oil Storage
- API 651, Cathodic Protection of Above Ground Storage Tanks
- API 652, Lining of Above Ground Petroleum Storage Tank Bottoms
- API 653, Section 4—Inspection
- **API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning and Stray Currents (DOT HQ Audit May 11/01) 195.432**
- API 2015, Safe Entry and Cleaning of Petroleum Storage Tanks
- API 2026, Safe Descent Onto Floating Roofs of Tanks in Petroleum Service
- API 2027, Ignition Hazards Involved in Abrasive Blasting of Atmospheric Storage Tanks in Hydrocarbon Service
- API 2207, Preparing Tank Bottoms for Hot Work

195.432
Q.35

Canadian Council of Ministers of the Environment (CCME):

- Environmental Code of Practice for Aboveground Storage Tank Systems Containing Petroleum Products

Purpose

Tank inspections confirm the structural integrity of the tank and its continued fitness for use.

Requirements

Inspection Frequency

Inspect in-service and out-of-service crude oil storage tanks on a schedule consistent with the recommended guidelines of API 653, Section 4--Inspection. Table 1 summarizes the types and frequencies of tank inspections. **Requirements for inspecting physical integrity of in-service aboveground breakout tanks (bullet tanks) according to API 2510, Section 6, to be added here (DOT HQ Audit May 11/01) 195.432**

195.432
Q. 35

Qualifications

Employees assigned to do a Routine-In-Service Inspection must be familiar with tank farm operation, the tank and the characteristics of the product stored, e.g., terminal gauger, terminal supervisor, station chief, PLM supervisor or designate.

Inspection teams assembled to do a Formal In-Service or Formal Out-of-Service Inspections must be comprised of knowledgeable employees from regional/district offices, terminals/stations, and Pipeline Maintenance (PLM) or Engineering. One member of the inspection team must be certified as an Authorized API inspector as described in API 653.

Authorized API Inspectors

Authorized API inspectors must have education and experience equivalent to at least one of the following:

- degree in Engineering and one year of experience inspecting tanks, pressure vessels or piping
- two-year certificate in Engineering or Technology from a technical college, and two years of experience in operation, construction, repair or inspection, of which one year must be in the inspection of tanks, pressure vessels or piping
- equivalent of high school education and three years of experience in construction, repair, operation or inspection, of which one year must be in the inspection of tanks, pressure vessels or piping

- five years of experience in inspecting above-ground storage tanks in the petroleum or chemical industries

Table 1
Types and Frequencies of Tank Inspections

Type of Inspection	Maximum Interval	Done by
Routine In-Service	Monthly	local terminal operations employees
Routine In-Service	Annually	local terminal operations supervisor PLM supervisor or designate
Formal In-Service	5 years[1]	authorized API inspector[2]
Formal Out-Of-Service	20 years[1, 3]	inspection team and authorized API inspector[2]

NOTES
1 More frequent inspections may be required due to corrosion.
2 May be a person who is not a company employee.
3 Frequency may be extended if a risk-based inspection (RBI) assessment is done according to API 653.

Evaluation—Repairs—Alterations

After routine inspections, evaluate documentation to determine:

- requirement for leveling tank
- extent of repairs required
- repair method
- requirement for hydrostatic testing

Refer major maintenance or operational issues to the station chief/terminal supervisor.

The inspection team must consult with Engineering on integrity issues that require repairs or alterations to a storage tank.

Records

Routine Inspections

Monthly

Check tank exteriors, including roofs, and document conditions in the terminal log. **Further clarification of conditions for conducting monthly routine inspections on tanks as well as corrective action when problems are found to be added here (DOT HQ Audit May 11/01) 195.432**

195.432 Q.35

Name of Operator:	Lakehead Pipe Line Company Inc.

HQ Address: Lakehead Pipe Line Company Inc. 1100 Louisiana, Suite 2950 Houston, TX. 77002	**System/Unit Name Address:** Crude System # 1
Co. Official (Pres or VP) Dan C. Tutcher; President **Telephone number:** 713-650-8900 **Fax number:** 713-650-3232 **Emergency Telephone:** 800-858-5253	**Telephone number:** **Fax number:** **Emergency Telephone:** 800-858-5253

Operator ID: 11169	**Unit ID:** 152 (System ID)	**Activity ID:** 93252, 91730, 91794

Unit IDs of adjacent Operator units:

Persons Interviewed	Titles	Phone Numbers
Refer to attached copies of		
attendance sheets.		

OPS Representative(s): David Barrett and Phil Archuletta (OPS CRO) Brian Pierzina and Boyd Haugrose (MNOPS)

Company system maps - (copies for regional files, yes / no): Yes, placed in operator's file.

System/Unit Description:

System: Lines from the North Dakota /Canadian border to Superior, WI.
The system includes the following Central Region units:

Unit # 3083	All Lines in Minnesota
Unit # 16123	North Dakota
Unit # 1323	Superior

Portion of Unit Inspected:

Operator headquarters in Duluth, MN.
Pipeline facilities from the North Dakota / Canadian border to the North Dakota / Minnesota border (by OPS CRO). Inspection included the pump station at Joliette, ND.
Pipeline facilities from the North Dakota / Minnesota border to the Minnesota / Wisconsin border (by MNOPS).
Pipeline facilities at the Superior, WI station/terminal (by OPS CRO).

Was a Team O&M inspection completed previously? No	**If yes, document date?** / /

Note: If a Team O&M inspection was completed within the five (5) years, it is not necessary to review the entire O&M manual. However, modifications to the manual should be reviewed.

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description LAKEHEAD HEADQUARTERS INSPECTION
Date 5/8 Location Duluth, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	Staff Engineer	U.S. DOT - OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Dave Barrett	Engineer	US DOT - OPS	816 329 3817	david.barrett@rspa.dot.gov
3	Brian Pierzina	Sr. Engineer	MN OPS	218-327-4218	brian.pierzina@ state.mn.us
4	BOYD HAUGROSE	Eng. Spec.	MNOPS	218-847-7367	~~boyd.haugrose@state.mn.us~~
5	Doug A Klein	Safety & Compliance	Enbridge (U.S.)	218-725-0444	doug.klein@uspl.enbridge.com
6	Dave McNeill	Supervisor Integrity	Enbridge (US).	218-725-0595	dave.mcneill@uspl.enbridge.com
7	John Sobojinski	Operations Services Manager	Enbridge (US)	218-725-0505	John.Sobojinski@uspl.enbridge.com
8	Janet Huggett	Sr. Technical Writer	Enbridge Pipelines	780-420-5142	Janet.Huggett@cnpl.enbridge.c
9	VINCE KOLBUCK	ENGINEER	ENBRIDGE U.S.	218-725-0563	vince.kolbuck@uspl.enbridge.com
10	Tom Lohman	Engineer	Enbridge US.	218 725-0568	tom.lohman@uspl.enbridge
11	Don Scott				
12	Tanis Elm	Sen Engineer	Enbridge US	218 725-0495	tanis.elm@uspl.enbridge.com
13	GAIL FOLLIS	ENG. SERVICES	ENBRIDGE US	218-725-0536	GAIL.FOLLIS@USPL.ENBRIDGE.C
14	Nadine Lohman	Design & Serv. Clerk	Enbridge US	218-725-0537	Nadine.LOHMAN@USPL.Enbridge.c
15	ERIC A. WILLIAMS	SAFETY + COMPLIANCE	ENBRIDGE U.S.	219-922-3133	ERIC.WILLIAMS@USPL.ENBRIDGE.com

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description Records Review

Date 8-27-01 **Location** Duluth, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	General Engineer	US DOT - OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Kimberly J. Harris	Sr. Corrosion Tech.	LPL/ Enbridge Energy Partners	219-922-3133 x202	Kimberly.Harris@USPL.Enbridge.Com
3	John Sobojinski	Manager-Compliance + Risk Management	Enbridge (US)	218-725-0505	John.Sobojinski@USPL.Enbridge.com
4	DAVID MCNEILL	SUPERVISOR PIPELINE INTEGRITY	ENBRIDGE (US)	780-420-8731	
5	GARY HAUBRICH	TECH SUPERVISOR	LPL	218-759-6614	
6	RANDY WILBERG	SAFETY TRAINING COMPLIANCE	ENBRIDGE U.S.	715-394-1412	RANDY.WILBERG@USPL.ENBRIDGE.COM
7	Todd Gilseth	Safety Analyst	" "	218-759-6615	Todd.Gilseth@USPL.Enbridge.Com
8	Doug A. Klein	Safety Team Leader	Enbridge U.S	715-394-1437	doug.klein@uspl.enbridge.com
9	JAY A JOHNSON	COMPLIANCE COORDINATOR	" "	218/725-0512	jay.johnson@uspl.enbridge.com
10	Dave Barrett	Engineer	OPS	816-329-3817	david.barrett@rspa.dot.gov
11	Brian Pierzina	Sr. Engineer	MNOPS	218-327-4218	brian.pierzina@state.mn.us
12					
13					
14					
15					

MOP/Overpressure Protection

Overpressure protection is essential to protect the pipeline from unexpected events. The operator should have procedures in place to ensure that the overpressure protective devices are adequate and in good working condition.

195.406(a)(1) Maximum Operating Pressure - Determining the MOP from design or test pressure or integrity calculations.

195.404(a)(3) Maps and Records - Each operator shall maintain current records of the maximum operating pressure of each pipeline system.

G-Q1) Does the operator have records to support the MOP applied to each line segment?

R1) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q1) Headquarters	X			
Q1) Field			X	
R1) Headquarters	X			
R1) Field			X	

1) Comments: The MOP of each pipeline segment was established by hydrostatic testing. The hydrostatic tests accounted for elevation differences and the characteristics of the products transported. System dynamic models are used to help determine pipeline parameters such as pressure setpoints. Different scenarios are run on the models to determine if any pressure changes are required. Pressure setpoints and allowances are determined by Lakehead's engineering department. Pump station base maximum discharge (BMD) pressures are set equal to are less than the established MOP for the entire line segment. For surge pressures, a first alarm warning is set at 5psig above BMD, a cascade shutdown of units at the station PLC is set at 25 psig above BMD, a cascade shutdown of units by the SCADA center is set at 35 psig above BMD and a complete shut-down of the entire pipeline is set at 65 psig above BMD or 110% BMD.

195.404(b)(1) Record of Discharge Pressure - Actual operating pressures representing three years of data.

G-Q2) Does the operator's pressure recording system retain sufficient details of pressure events, so as to exhibit pressure spikes that may have breached the MOP?

R2) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q2) Headquarters			X	
Q2) Field	X			
R2) Headquarters			X	
R2) Field	X			

2) Comments: Lakehead has begun a program to replace pen & ink pressure recorders with digital pressure recorders. Currently, 40 out of approximately 100 recorders have been replaced. These are six channel digital recorders which look at pressure every second, records the pressure every minute and records the highest and the lowest pressure within that one minute span, however, the exact time of each high/low is not kept. If an event causes a cascade shut-down, then the recorders capture all pressures between 5 minutes before and 5 minutes after the shut-down. The pressure data is stored on zip disks and one year's worth of data can be stored on one zip disk. The data is also sent and recorded at Lakehead's headquarters server as a backup.

195.428(a) Overpressure Safety Devices - Each operator shall at intervals not exceeding 15 months, but at least each calendar year, or in case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good working condition, and is adequate from the stand point of capacity and reliability of operation for the service in which it is used.

G-Q3) Have pressure safety devices been checked for pressure accuracy in one year intervals, or six month intervals for highly volatile liquids?

R3) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q3) Headquarters			X	
Q3) Field	X			
R3) Headquarters			X	
R3) Field	X			

3) Comments: Pressure safety device inspections are recorded in Maximo. Station safety devices (pressure switches and transmitters) are checked semi-annually. Pressure relief valves are checked annually. Verified by records review at Duluth.

195.128 Station Piping - Must meet applicable requirements if subjected to system line pressure.

G-Q4) Have the appropriate pressure controlling devices been installed to protect the lower-pressure piping in the manifold and/or at pump stations?

R4) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q4) Headquarters	X			
Q4) Field	X			
R4) Headquarters			X	
R4) Field			X	

4) Comments: Pressure controlling device procedures / criteria are contained in Lakehead's Engineering Standard D12-104. Lakehead uses a tiered approach to pressure control alarming/shut-down. The tiers are 1) alarm, 2)shut-down and 3)high-high shut-down (a station shut-in will also occur). Redundant transmitters are used to send data back to the PLC. The PLC uses the lowest transmitter pressure reading for control. Setpoints at station PLC's are established based upon what product is being transported. Some of Lakehead's stations also use variable frequency drive pumps to control discharge pressures. Surge relief for NGL's is provided by bullet tanks located at Lakehead's Superior Terminal/Station.

195.402(d)(1) Abnormal Operation - Responding to, investigating and correcting the cause of unintended closure of valves or shutdowns; and an increase or decrease in pressure or flow rate outside normal operating limits.

195.404(b)(2) Maps and Records - Each operator shall maintain for at least 3 years daily operating records of any emergency or abnormal operation.

G-Q5) Did the safety devices function properly during abnormal operation?

R5) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q5) Headquarters	X			
Q5) Field	X			
R5) Headquarters			X	
R5) Field	X			

5) Comments: High pressure shut-down is provided at delivery points. Lakehead has a policy that if a high pressure or other abnormal event cannot be resolved in 10 minutes, then a shut-down is initiated. Verified by records review at Duluth.

195.402 (d)(2) Procedures for checking variations after abnormal operations - Checking for safe operation at sufficient critical locations to determine continued integrity and safe operation.

195.404(b)(2) Maps and Records - Each operator shall maintain for at least 3 years daily operating records of any emergency or abnormal operation.

G-Q6) Are procedures and forms used to document the occurrence of unscheduled shutdowns and over-pressure situations?

R6) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q6) Headquarters	X			
Q6) Field			X	
R6) Headquarters	X			
R6) Field			X	

6) Comments: Abnormal events are recorded on Pipeline Incident forms in the field. Lakehead's control center uses a "Facilities Management" (FACMAN) report for reporting such events as station unit problems, lockouts, overpressures and any significant activity that is considered outside of ordinary operations. Events generate internal memos and messages to field operations on causes, corrective actions and preventive procedures. Events involving surge relief valves are FACMAN not recorded. All FACMAN records are kept at Lakehead's Edmonton, Alberta, Canada office.

195.402(d)(5) Procedural manual for operations, maintenance, and emergencies - Abnormal Operation - Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

G-Q7) Does the procedure direct the analysis of abnormal conditions to prevent future abnormal events?

R7) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q7) Headquarters		X		
Q7) Field			X	
R7) Headquarters			X	
R7) Field			X	

7) **Comments:**Lakehead did not have a formal written procedure for analyzing abnormal events. Lakehead looks at what happened and why, but there was no direction as to how analysis is done on a company wide basis. Lakehead has a "PIPELINE CONTROL COMMITTEE" that meets quarterly to review philosophies, give direction/coordination and establish priorties for the control/operation of Lakehead's pipelines. The goal of the committee is to achieve a safe, efficient, environmentally sound operation compliant with regulations.

195.302(c) - Compliance deadlines for pipelines that have not been pressure tested.

G-Q8) Has the operator developed a plan for testing its pipeline systems?

R8) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q8) Headquarters			X	
Q8) Field			X	
R8) Headquarters			X	
R8) Field			X	

8) **Comments:**All of Lakehead's pipelines have already been tested.

195.426 Scraper and Sphere Facilities - Pressure indication and relief devices.

G-Q9) Do traps have functioning visual or audible indications of pressure to alert operating and maintenance personnel about elevated trap pressure?

R9) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q9) Headquarters			X	
Q9) Field	X			
R9) Headquarters			X	

R9) Field			X	

9) Comments: Lakehead's procedures on traps are in Lakehead's O & M Book 3, Section 08-03-01and 08-03-02. Field inspections verified that traps are provided with devices to alert personnel about high pressure in the trap.

Inspection Criteria relating to SCADA and other Alarm Systems

195.262(a) Pump Station Ventilation and Warning Devices - Detecting hazardous vapors.

G-Q10) Has the operator installed warning devices in pump station buildings to warn of the presence of hazardous vapors?

R10) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q10) Headquarters	X			
Q10) Field	X			
R10) Headquarters			X	
R10) Field			X	

10) Comments: Procedures for detecting the presence of hazardous vapors are in Lakehead's Engineering Standard D12-202. At Lakehead's pump stations, there are vapor detectors located either near the units or along the interior building walls. Visual alarm on the local PLC panel. The control center also receives an alarm. The devices give a warning at 20% LEL and a alarm and shut-down at 40 % LEL. Thermal (heat) switches are provided above each pump unit for fire detection and are set at 125° F.

195.402(c)(9) Facilities not equipped to fail safe - As described in 195.402(c)(4), facilities that are located in areas that control the receipt and delivery of hazardous liquids would require an immediate response by the operator to prevent hazards to the public must be monitored... usually by SCADA if unattended.

G-Q11) Are all the unattended locations on the operator's system which control the receipt and delivery of hazardous liquids monitored?

R11) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q11) Headquarters	X			
Q11) Field	X			
R11) Headquarters			X	
R11) Field			X	

11) Comments: All remote locations are monitored by Lakehead's control center in Edmonton, Alberta, Canada. Equipment is designed to fail-safe. Lakehead has backup communication systems if the primary systems fail. A loss of communications causes local PLC's to go to limits which significantly reduces line through put rate. If communications at a remote site are lost for more than 10 minutes, then the control center will start a systematic shut-down procedure.

195.408(a) Communications System for Pipeline Information - Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline.

G-Q12) Will system operation be affected by communication outages or SCADA failure?

R12) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q12) Headquarters	X			
Q12) Field			X	
R12) Headquarters			X	
R12) Field			X	

12) Comments: Lakehead has a back-up control center located in Superior, WI. The back-up center has 5 to 6 consoles and in the event that a console fails, any one of the other consoles can be used. If for any reason, the building housing the control center at Edmonton had to be evacuated, then the control center would shut-down all pipelines and personnel would temporarily relocate to a another back-up control center at a Edmonton terminal that is approximately 15 to 20 minutes from the main control center. Control personnel would then begin a systematic re-start of all pipelines. Back-up control centers are tested a minimum of two times per year.

G-Q13) Best Practice:
Does the operator have a means to prevent controller fatigue?

13) Comments: The Lakehead control center at Edmonton, Alberta, Canada has ergonmically designed console controls, chairs and room lighting. There are two 12 hour shifts, 7:00AM - 7:00PM and 7:00PM - 7:00AM. The controllers work 2 days, 3 nights and then have 5 days off. They then work 3 days, 2 nights and have 5 days off. Controllers are provided with a tread mill for excersice and a mini-kitchen. Controllers are cross-trained there is rotation among the consoles. Normal operation is to have one operator per console per shift. There is one control center coordinator per shift to supervise the controllers.

EVALUATION OF COMPUTATIONAL PIPELINE MONITORING (CPM) SYSTEMS FOR HAZARDOUS LIQUID PIPELINE SYSTEMS

195.134 Definition and application of the computational pipeline monitoring (CPM) leak detection system.

G-Q14) Does the operator have a leak detection system?

R14) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q14) Headquarters	X			
Q14) Field			X	
R14) Headquarters			X	
R14) Field			X	

14) Comments: Leak detection systems are provided for Lines 1, 2, 3, 5 and 13. A leak detection system for Line 4 is almost ready, the system is installed but the alarms are not active because they are fine tuning the settings. A leak detection system for Line 6 has been budgeted. Leak detection is not provided for Lines 14 and 17(probably will be done next year). The system used is a Stoner Leak Detection System which uses real time transient hydraulic modeling of the pipelines. The system compares the model with what is actually occurring on the pipelines. The sensitivity ranges vary for each line, but an example would be Line 3 where the sensitivity is 28% of total flow over 5 minutes, 11% over 20 minutes and 6% over 2 hours. The leak detection system is part of the "10 minute" rule, which means that if the reason for a leak detection indication cannot be resolved within 10 minutes, then the line will be shut-down.

195.404(c)(3) Maps and Records - Each operator shall maintain a records for two years.

G-Q15) Does the operator maintain records per the requirements of 195.404(c)(3)?

R15) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q15) Headquarters	X			
Q15) Field	X			
R15) Headquarters	X			
R15) Field	X			

15) Comments: Procedures for record keeping requirements are found in Book 1, Sections 05-01-01 and 05-02-01 of Lakehead's O & M manual. Records such as PLM Reports, Permanent Repair Reports and Corrosion Inspection Reports are in Lakehead's PLM databases.

Field: Bemidji and Superior Districts - Records reviewed were in compliance.

Engineering Drawing Review

195.402(c)(1) Maintenance and Normal Operation - Making construction records, maps, and operating history available for safe operation and maintenance.

G-Q16) How does the operator control engineering drawing revision, review, approval, and distribution?

R16) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q16) Headquarters	X			
Q16) Field	X			
R16) Headquarters	X			
R16) Field	X			

16) Comments: Lakehead's drafting department has responsibility for drawing development and distribution. The process for handling drawings are located in Lakehead's Engineering Procedures. Project Engineers have responsibility for making sure that as-builts are accurate (with regard to what was installed) and completed at the end of each construction project. Drafters go to the field to verify dimensional accuracy. It takes approximately 1 to 2 months to have changes placed on the alignment sheets and new alignment sheets are issued toward the end of the year, usually December or January. Field personnel use mark-ups in the interim. Flow diagrams are the first drawings to be updated and any changes that would effect the control center are submitted to the control center for incorporation into control center screens and operations.

195.404(a) Each operator shall maintain current maps and records of its pipeline systems.

Q17) Do the operator's "as-built" agree with field? Do the SCADA terminals get updates?

R17) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q17) Headquarters	X			
Q17) Field	X			
R17) Headquarters			X	
R17) Field	X			

17) Comments: Refer to comments under Q16.

Field: Bemidji and Superior Districts - Field drawings were reviewed against actual field facilities and were OK.

195.402(c)(1) Maintenance and Normal Operation - Making construction records, maps, and operating history available for safe operation and maintenance.

Q18) How are completed construction activities, such as facility modifications, communicated to the controller?

R18) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q18) Headquarters	X			
Q18) Field			X	
R18) Headquarters	X			
R18) Field			X	

18) Comments: Lakehead has a PLC coordinator and on any new projects, the coordinator works with the project engineer to see what is needed if PLC programming changes are required. Programs are stored at the headquarters level server along with hard copies. Field technicians have hard copies and storage disks. All PLC programs are protected with a "read only" feature. Refer to comments for Q16 for additional information.

Process Control and Flow Schematic Drawing Review

Differences between process control engineering drawings and pipeline facilities have resulted in incidents and abnormal operating conditions. We have found that physical changes made to facilities are sometimes not reflected in engineering drawing or SCADA displays. The company should have a procedure in place that ensures changes in the field are communicated to appropriate personnel and correspondence (i.e. maps, records and drawings) are corrected.

195.404(a) Each operator shall maintain current maps and records of its pipeline systems.

G-Q19) Do engineering, process control, and flow schematic drawings adequately depict current facilities and operations?

R19) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q19) Headquarters	X			
Q19) Field	X			
R19) Headquarters	X			
R19) Field	X			

19) Comments: Field: Bemidji and Superior Districts - Field drawings were reviewed against actual field facilities and were OK.

Review of First Discovery Reports

First discovery reports are reports that may identify potential problems on, or in the vicinity of the pipeline, that could affect pipeline integrity and/or public safety. These reports could include any pipeline safety inspection and/or survey reports, landowner or general public reported concerns, patrol reports. Listed below are a few high impact examples.

195.416(e) External Corrosion Control - the operator shall examine exposed pipe for external corrosion.

195.416(i) External Corrosion Control - the operator shall clean, coat for the prevention of atmospheric corrosion

195.401(b) Operation and Maintenance - the operator shall correct any condition that could adversely affect the safe operation of its pipeline within a reasonable time.

G-Q20) Does the operator disseminate, monitor, and follow-up the information obtained from first discovery reports?

R20) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q20) Headquarters		X		
Q20) Field		X		
R20) Headquarters			X	
R20) Field	X			

20) Comments: Lakehead's procedures require modification to include first discovery reports from the public, employees, contractors and sources other than those that are reported directly to the control center.

Field: Bemidji and Superior Districts - Discovery reports and follow up records were reviewed and were OK.

195.416(e) cont'd

G-Q21) Does the company follow-up and document discovered exposed spanning pipe in water and do they take fluctuating water levels into consideration?

R21) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q21) Headquarters	X			
Q21) Field			X	
R21) Headquarters			X	

R21) Field			X	

21) **Comments:** Whenever field personnel discover exposed spanning pipe that may require evaluation, then Engineering is notified. Engineering does an analysis (including evaluation of stresses) and prepares a plan of action for corrective measures needed. Exposed pipe is handled on a case-by-case basis and a formal list of all exposed pipe locations is not kept. A table of maximum allowable length between pipe supports is located in Book 3 of Lakehead's O & M manual. The table shows that the range of unsupported pipe lengths is 80 to 115 feet depending on pipe diameter and wall thickness.

195.408(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system, and (b) The communication system required by paragraph (a) of this section must, as a minimum, include means for: (1) Monitoring operational data as required by §195.402(c)(9);(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and (4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.

G-Q22) How does the operator follow-up and document public/landowner complaints concerning safety and integrity issues?

R22) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q22) Headquarters	X			
Q22) Field	X			
R22) Headquarters	X			
R22) Field	X			

22) **Comments:** Most complaints would go to Lakehead's 800 emergency number at the control center. These calls would be recorded on an incident information form. An initial assessment would be done to determine if an immediate shut-down is required. If there is a shut-down, it is recorded in LPL's "Facilities Management" (FACMAN) program. The first call would be to the police, if necessary. The second call would be to field personnel to respond to and investigate the called in report.

195.401(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under §195.402(a) of this subpart; and (b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct

it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

195.404(b) Each operator shall maintain for at least 3 years daily operating records that indicate-

(1) The discharge pressure at each pump station; and
(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

(c) Each operator shall maintain the following records for the periods specified;

(1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.
(2) The date, location, and description of each repair made to parts of the pipeline other than pipe shall be maintained for at least 1 year.
(3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

G-Q23) How does the operator follow-up and document integrity issues system-wide?

23) Comments: Lakehead has a "Pipeline Integrity" (PI) group which is responsible for the overall integrity management program. When internal inspection tool runs are made, results go to the PI group which does an analysis for data validity and defects that are of a critical nature. Priority is first given to anomalies considered to be of a critical nature. The PI group also prepares any dig list. The PI group communicates with field personnel and vendors on what is actually found versus what the tool run data reported. Historically, LPL has not used integration of CP and pig run data to analyze potential problem areas. However, LPL is in the initial stages of using an integration of data program. A close interval survey is done every 5 years an a rotating basis among the district areas.

Training

Operator errors result in pipeline incidents every year. We are trying to determine what processes operators have in place to address the training requirements and safety needs of the pipeline industry.

195.403 Training

G-Q24) Has the operator established and conducted a continuing training program to instruct operating and maintenance personnel?

R24) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q24) Headquarters	X			
Q24) Field	X			
R24) Headquarters	X			
R24) Field	X			

24) Comments: Initial training is per Performance Based Training (PBT). PBT has 3 levels of training for each position as follows - 1) performed the task; 2) assisted in performing the task and 3) received an explanation/demonstration of the task. PBT requires that the employee's supervisor sign off when a job/task is completed. LPL maintains a database for recording tasks, dates of performance and sign off dates.

195.403 Cont'd

Q25) Does the operator review, at intervals not exceeding 15 months, but at least once each calendar year, the performance of their personnel in meeting the objectives of the training program?

R25) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q25) Headquarters	X			
Q25) Field	X			
R25) Headquarters	X			
R25) Field	X			

25) Comments: LPL's training procedures include an annual performance review of personnel. A review is also done on the training topics to see how topics can be improved to meet training objectives.

195.509(a) Operators must have a written qualification program by April 27, 2001.

G-Q26) Has the operator developed a written qualification program?

R26) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q26) Headquarters	X			
Q26) Field			X	
R26) Headquarters	X			
R26) Field			X	

26) Comments: LPL's operator qualification program has been in development over the past 2 years. LPL now has a formal written OQ plan with an effective date of 4/27/01. The elements of the plan meet the criteria of the OQ regulation.

Corrosion Control

Corrosion is a major cause of accidents and disbonded coating is often the leading factor. A check of close interval surveys for depressed areas may reveal disbonded coating. Pipe segments adjacent to locations where corrosion is found could easily develop corrosion because it may be subject to the same conditions. Additional preventive measures should be taken in these areas such as bell hole examinations and smart pigging activities. Review locations where clock-spring repairs were made to identify pipe segments that are subject to active corrosion.

195.414 Cathodic Protection

195.416 External Corrosion Control

195.418 Internal Corrosion Control

G-Q27) Does the company maintain a comprehensive corrosion control program?

R27) Associated Records (annual survey, rectifiers)?

	Satisfactory	Needs Improvement	N/A	N/C
Q27) Headquarters	X			
Q27) Field	X			
R27) Headquarters			X	
R27) Field	X			

27) Comments: LPL maintains a comprehensive corrosion control program which covers both internal and external corrosion. There is one senior corrosion technician located at LPL's Chicago District office. This senior corrosion technician assists with corrosion issues on a company wide basis. Corrosion issues at the District level are handled by a corrosion technician based out of each District office. The actual surveys are done by a third party contractor and the District corrosion technician reviews the contractor's work to ensure compliance with company criteria and regulations. Program includes close interval surveys, CP interference tests with other companies, "on-off" surveys and recently includes sharing of information between the pipeline integrity group and the corrosion control group.

G-Q28) Best Practice: Industrial Standards - RP0169, NACE
Is the company's corrosion program under the direction of a qualified person? (List the qualifications in the comment field.)

28) Comments: Each district is responsible for and manages the corrosion control program within the district. The company has a Senior Corrosion person based at of Griffith, Kimberly Harris, who is available to assist with problems and questions on a system wide basis. Ms. Harris is a Certified Corrosion Technologist.

195.402 Procedural Manual for Operation, Maintenance, and Emergencies - the operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

G-Q29) Are corrosion control procedures in place and do they follow Part 195/NACE/industry standards?

R29) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q29) Headquarters	X			
Q29) Field	X			
R29) Headquarters			X	
R29) Field			X	

29) Comments: LPL's corrosion control program follows Part 195 and NACE standards. Corrosion control procedures are found in Book 3 of Lakehead's O & M manual. Refer to the comments for Q27 for additional information.

195.402 cont'd

195.414 cont'd

195.416 cont'd

195.418 cont'd

G-Q30) How is the gathered information reviewed and analyzed to identify problem areas?

R30) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q30) Headquarters	X			

Q30) Field	X			
R30) Headquarters	X			
R30) Field			X	

30) Comments: In the past, LPL has not integrated CP data with pipeline internal inspection data to identify problem areas, but this has recently changed as LPL's integrity management group seeks to improve the integrity program. Company experts meet to determine what the integrity program/plan should be. Many factors are considered in the plan and an Enbridge wide plan is developed. The integrity plans are developed as a system, but each line is individually evaluated.

195.401(b) Operation and Maintenance - the operator shall correct any condition that could adversely affect the safe operation of its pipeline within a reasonable time.

G-Q31) Under what conditions does the operator take prompt remedial action?

R31) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q31) Headquarters		X		
Q31) Field			X	
R31) Headquarters			X	
R31) Field			X	

31) Comments: Priority for prompt remedial action is given to problems that may indicate an imminent failure, would result in a immediate impact on the pipeline MOP or flow rate, would impact on public safety or would impact environmentally sensitive areas. Beta foils are used to determine internal corrosion problems, but LPL needs formal written procedures detailing how beta foils are used, criteria required and what the corrective process is when the beta foils due indicate a problem. The beta foil data is analyzed by a third party contractor. The pipeline integrity group uses internal inspection data to determine problem areas and corrective actions required. LPL has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of LPL's pipeline systems, especially with regard to corrosion control procedures and remedial actions taken. However, LPL has not formalized the process by inclusion of specific verbage in LPL's O & M manual.

Q32) Best Practice:
What factors are considered in determining the need for and timing of pigging and close interval surveys?

32) Comments: Lakehead uses such factors as coating type, product type, leak history, pipe type, operation history, internal inspection history, defect history and seam weld type. Lakehead will begin using an overlay of high resolution tool runs to determine corrosion rates to determine future intervals for tool runs. Close interval surveys are done every 5 years.

Tanks

Inspection criteria relating to Tankage.

195.2 Definition - Breakout Tank means a tank used to (a) relieve surges in *hazardous liquid pipeline system* or (b) receive and store hazardous liquid transported by a pipeline for re-injection and continued transportation by pipeline.

G-Q33) Has the operator correctly identified/classified its tanks?

R33) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q33) Headquarters	X			
Q33) Field	X			
R33) Headquarters			X	
R33) Field			X	

33) Comments: Tanks identified as breakout tanks and OPS jurisdictional at Superior, Clearbrook, Stockbridge and Griffith. The NGL bullet tanks at Superior are used strictly for surge pressure relief. Tanks are considered to be dual jurisdictional between OPS and the ICC at the Hartsdale Terminal. The Hartsdale tanks are storage tanks that can be used for "lease".

195.428(b) Over pressure safety devices - In case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

G-Q34) Does the operator ensure relief valves are tested?

R34) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q34) Headquarters	X			
Q34) Field	X			
R34) Headquarters			X	
R34) Field	X			

34) Comments: There are relief valves on the NGL bullet storage tanks at Superior. These relief valves are tested every 5 years.

195.432 Breakout tanks - Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each breakout tank (including atmospheric and pressure tanks).

G-Q35) Has the operator conducted the appropriate inspections? Does the operator use available industry codes and standards to uniformly establish maintenance and repair inspection criteria for the breakout tanks?

R35) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q35) Headquarters		X		
Q35) Field		X		
R35) Headquarters			X	
R35) Field	X			

35) Comments: Procedures for tank inspections are located in Book 3, Section 09-02-02 of Lakehead's O & M manual. LPL's procedures need revision to include verbage on what the corrective action process is if problems are found during any breakout tank inspection. LPL should implement a method to address conclusions and recommendations made during a tank inspection, and the status of corrective actions. The procedures also need specific references to industry standards API 2003 and API 2510. The procedures need specific verbage on what items to look for during tank inspections. LPL uses API653 inspection criteria. The tank floors are given a 100% MFL scan. The inside seam on the bottom of the tank is given a 100% vacuum box test. LPL does not have a centralized tank inspection program run from headquarters. The headquarters tank personnel act in an advisory role to the Districts. The Districts maintain the inspection records, request funds for inspections and decide on threshold intervals for tank inspections.

G-36) Best Practice:
Are the breakout tanks equipped with high level alarms?

36) Comments: Lakehead's breakout tanks have two stages of high level alarms set at "High" and at "High - High". The "High - High" alarm is independent of the "High" alarm. The "High" level is via a tape type floating gauging system. The tape gauging system also includes a gauge near the bottom of each tank which can be used for a visual indication of the tank's level.

Valves

It is important that isolation valves be in good working order and accessible when needed.

195.116 Valves

G-Q37) Has each valve been properly designed, marked, and tested?

R37) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q37) Headquarters	X			
Q37) Field	X			
R37) Headquarters			X	
R37) Field			X	

37) Comments: Specifications for Lakehead's valves are located in Lakehead's Engineering Standard D06-105. Engineering sets the specifications for all valves. Lakehead orders valves meeting API6D criteria. The valves are full open port, rising stem valves. All mainline valves are ordered with a open/close indicator.

195.260 Valve Locations - A valve must be installed at each of the following locations: on the suction and discharge end of a pump station; on each line entering or leaving a breakout tank area; along the pipeline that will minimize damage or pollution from accidental discharge; on each lateral takeoff from the trunk line; on each side of a water crossing that is more than 100 feet wide at high-water mark; and on each side of a reservoir holding water for human consumption.

G-Q38) Are mainline valves properly identified and located?

R38) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q38) Headquarters	X			
Q38) Field	X			
R38) Headquarters			X	
R38) Field			X	

38) Comments: Lakehead considers any valve that blocks, controls or isolates mainline flow is a mainline valve. A risk management type process is used to identify where valves should be located. Priority consideration is given to high risk areas such as wetlands. Mainline valve lists are maintained in each district.

195.420(a) Valve Maintenance - the operator shall maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.

G-Q39) Does the operator maintain each valve that sees mainline pressure and flow in good working order?

R39) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q39) Headquarters	X			
Q39) Field	X			
R39) Headquarters			X	
R39) Field			X	

39) Comments: Valve maintenance procedures are located in Book 3, Section 03-02-01 of Lakehead's O & M manual.

Field: Bemidji and Superior Districts - Field inspection included a random check and partial operation of valves to observe if the valves were in good working order. The valves in these districts were OK.

195.420(b) Valve Maintenance - the operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

G-Q40) Does the operator inspect each mainline valve on a bi-annual 7 ½ month basis to determine that their valves are functioning properly?

R40) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q40) Headquarters		X		
Q40) Field	X			
R40) Headquarters			X	
R40) Field	X			

40) Comments: LPL's procedures on valve inspections are confusing in that the procedures could be interpreted to mean that valve inspections are only done once per calendar year, when in fact, LPL inspects valves twice per calendar year per code requirements. The procedures need clarification so that there is no doubt that valves are to be inspected twice per calendar year. LPL did have one valve inspection interval that was exceeded due to flooding and it was suggested to LPL that comments regarding unusual conditions affecting inspections should be added to the valve inspection record.

Field: Bemidji and Superior Districts - Field check of records verified that valve inspections are done twice per calendar year.

195.420(c) Valve Maintenance - the operator shall provide protection for each valve from unauthorized operation and from vandalism.

G-Q41) Does the operator protect their valves from vandalism?

R41) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q41) Headquarters	X			
Q41) Field	X			
R41) Headquarters			X	
R41) Field			X	

41) Comments: Mainline valves are secured with a chain and padlock to prevent unauthorized operation. Steel pipe guard posts are installed around each valve that has the potential to be damaged from mowing activities, farming operations, land maintenance activities, street/highway/road maintenance activities and/or vehicular traffic.

Field: Bemidji and Superior Districts - Field inspection of random valve locations verified that valves are properly protected from vandalism.

195.404(c)(3) Maps and Records - Each operator shall maintain a record of their inspection of mainline valves for two years.

G-Q42) Does the operator maintain proper records for mainline valves?

R42) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q42) Headquarters			X	
Q42) Field	X			
R42) Headquarters			X	

R42) Field	**X**			

42) Comments: Records for mainline valves are kept in each District office.

Field: Bemidji and Superior Districts - Mainline valve records for this District were OK.

G-Q43) Best Practice:
Are valves located to provide quick response for environmentally sensitive areas such as drinking water sources, national parks, etc.?

43) Comments: For valve locations, priority is given to such areas as wetlands, high populated areas and major river crossings. When locations for valves are considered, Lakehead looks at such parameters as access for vehicles, availability of electric power and security measures required. In the event of a leak detection, all valves between the two adjacent stations would be closed. Lakehead's remotely operated valves have an average closure time of approximately 3 to 6 minutes. Lakehead does not have a overall conscious effort to identify environmentally sensitive areas to install valves, but Lakehead does have topographic maps with color coded sensitivity ratings which are used for response activity and emergency planning.

G-Q44) Best Practice:
Are there any locations where special features, such as valve stem extension in flood plains, had to be incorporated because of difficulty in complying with the above? Are there any automatic or remotely controlled valves?

44) Comments: Lakehead has used valve extensions on valves where appropriate. Some of Lakehead's more "critical" mainline valves, such as "sectionalizing" valves, are remotely controlled. In the event of a power failure, the remotely controlled valves stay open. Typically, Lakehead does not monitor the pressure at the remotely controlled valves. Some other strategic valves, such as stream/river crossings are a mixture of remotely operated and manually operated.

Patrol Program

An effective patrol program will combine information throughout the company to prevent damage to the pipeline and detect damage that has already occurred. Companies are encouraged to correlate information from a variety of sources such as comparing patrolling records with internal inspection data. Communication and areas of responsibility between patrol pilots and the personnel who follow-up and track the reports should be clearly defined so that both parties understand their role in preventing outside force damage.

195.402 Procedure Manual for Operations, Maintenance and Emergencies.

G-Q45) Does the operator have an adequate patrolling program ?

R45) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q45) Headquarters	X			
Q45) Field	X			
R45) Headquarters	X			
R45) Field	X			

45) Comments: Lakehead does aerial patrols every other week. Procedures for patrolling are located in Book 3, Section 03-02-01 of Lakehead's O & M manual. Aerial discoveries are reported on a "Daily Patrol Report" and are completed in electronic format. Field personnel respond to the reports and enter confirmation of actions taken electronically on company's computer. Lakehead uses it's own pilot for aerial patrol and helicopters are the main aircraft type used. If the helicopters are in for service, then Lakehead uses a third party aerial service out of Bemidji, MN. In the event of special conditions, such as flooding or sections that may be under a pressure restriction, the patrol frequency is increased. When a new pilot is hired, the new pilot will fly with the previous pilot for at least 2 weeks.

Line Markers and Damage Prevention (Locating and Marking Pipelines)

It is critical that personnel who locate buried pipe in the course of their work are qualified and competent. Personnel performing this work may be operator or contract service company employees (line locate company, corrosion survey company, pipeline surveyors, etc.).

195.410(a) Line Markers - each operator shall place and maintain line markers over each buried pipeline.

G-Q46) Are markers located at public road crossing, railroad crossings, and in sufficient number along the remainder of each buried line?

R46) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q46) Headquarters	X			
Q46) Field	X			
R46) Headquarters			X	
R46) Field			X	

46) Comments: Lakehead's policy is to place markers at road / railroad crossings, water crossings and other significant areas accessible to the public. At valve locations, LPL uses signs or markers or a combination of both.

Field: Bemidji and Superior Districts - Field check of random locations verified correct usage of signs and markers.

195.402(c)(13) Procedural manual for operations, maintenance, and emergencies - Maintenance and normal operations - the manual must include procedures for periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

195.442(a) Damage prevention program - if the operator does not participate in a public service program, such as a one-call system, then the operator of a buried pipeline must carry out a written program to prevent damage to that pipeline from excavation activities.

G-Q47) Does the operator participate in a public service program? If not, does the operator evaluate their damage prevention procedures and take corrective action where deficiencies are found?

R47) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q47) Headquarters	X			
Q47) Field	X			
R47) Headquarters			X	

R47) Field	X			

47) Comments: The public service programs that Lakehead participates in are 1) the One-Call program and 2) the Common Ground Alliance program. A LPL representative chars the API Damage Prevention Committee. LPL is in the process of preparing a table which is a comparison of the provisions from all the state One-Call programs that effect LPL. LPL would like to "push" the states toward similarity in state One-Call provisions. One-Calls are routed to LPL's headquarters, headquarters determines which District office is involved and forwards the One-Call requests to the appropriate District. Lakehead has a PC computer system which is solely dedicated to managing One-Call activities. One-Call records are located at various LPL pipeline maintenance (PLM) offices. There are 12 locations through out LPL's system that respond to One-Call reports.

195.442(c) Damage prevention program - the operator must identify, on a current basis, persons who normally engage in excavation activities in the area in which the pipeline is located; notify the public and persons who normally engage in excavation activities of the damage prevention program; provide a means of receiving and recording notification of planned excavation activities; provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings; and provide inspection of excavation activities, if the operator believes the pipeline could be damaged by excavation activities.

195.442(c)(3) Damage prevention program - if the operator participates in a public service program, such as a qualified one-call system, then the operator must: provide a means of receiving and recording notification of planned excavation activities.

G-Q48) Does the operator have an adequate damage prevention program?

R48) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q48) Headquarters	X			
Q48) Field	X			
R48) Headquarters			X	
R48) Field	X			

48) Comments: One-Calls are usually handled out of various LPL pipeline maintenance (PLM) offices within each District. LPL relies on the One-Call program to maintain a list of excavators. Whenever LPL receives a request from a third party to cross LPL's lines, LPL tries to obtain a formal written crossing agreement which details the parameters that LPL requires for a crossing.

G-Q49) Best Practice: NPRM Qualification of Pipeline Personnel
Are trained/qualified personnel used for pipeline locating & marking?

49) Comments: Lakehead uses only trained company employees to locate and mark lines. Line locating and marking is one of the covered tasks in Lakehead's operator qualification plan. Lakehead has 3 crossing coordinators who have attended the one week course at Staking University in Marysville, MI. These crossing coordinators then conduct field training of other LPL personnel. Vendors go to Lakehead field locations and train personnel on the use of specific line locating equipment.

Liaison with Construction Project and Land-Use Officials (Public Education)

Encroachment around pipelines poses serious safety risks as third parties excavate in proximity to buried pipelines. A strong damage prevention program will provide advance notification of construction plans near the pipeline and will establish communication with the people involved in the project.

195.440 Public Education - each operator shall establish a continuing educational program to enable the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator or the fire, police, or other public officials.

G-Q50) How does the operator implement its continuing education program?

R50) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q50) Headquarters	X			
Q50) Field	X			
R50) Headquarters			X	
R50) Field	X			

50) Comments: Lakehead's public awareness program is located in Book 1, Sections 04-01-01 and 04-02-01 of Lakehead's O & M manual. After identifying pubic officials that may need notifications, contact is made using mailings, face-to-face meetings and group meetings. Contact information is updated annually. General public awareness is through mailings of brochures, calendars and newspaper advertisements. LPL uses a API public awareness brochure as a multi-language mailing for landowners/tenants. Mailings to landowners/tenants is done annually. Every 3 years LPL tries for face-to-face meetings with groups and individuals who are located outside of LPL's right-of-way boundaries.

G-51) Best Practice:
Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

G-Q54) Best Practice:
Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

54) Comments: LPL is a member of the Common Ground Alliance. LPL has one member of the Common Ground committee. The Common Ground study was reviewed by approximately 6 Lakehead individuals.

G-Q55) Best Practice:
Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

55) Comments: Lakehead compared LPL's plan to the Common Ground practices and recommendations were forwarded to the District Managers.

G-Q56) Best Practice:
Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

56) Comments: Lakehead has modified their public awareness program based on some of the practices in the Common Ground study. Lakehead now sends two people out to audit One-Call centers. The modifications done to Lakehead's damage prevention program as a result of the Common Ground Study were minor in nature.

G-Q57) Best Practice:
Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

57) Comments: Lakehead incorporates the 4 or 5 points on digging/damage prevention in the study. Lakehead looks at damage prevention as a whole process that goes beyond just "call before digging". LPL feels that "call before digging" should include all steps (call in, wait the required time interval, pay close attention to the pipeline company's markers, use safe procedures while digging, etc.) Lakehead has modified their internet website to provide better public awareness.

Field Verification of Facility Response Plan Information		Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number **865 District 3, 866 District 4, 867 District 5, 868 District 7** Approval Date **2/17/95 Renewal pending via DOT letter dated 3/20/01.** [See Guidance OPA-1]	X		
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			X
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]	X		

OPA Inspection Guidance

OPA-1 - **RSPA Tracking Number**: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - **Names and phone numbers**: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - **Proof of OSRO contract**: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - **Exercise documentation**: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - **Training records**: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: LAKEHEAD PIPELINE
Date(s): 8-30-01
Unit: North Dakota

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 801.10						
Red River -West Side						
18" Valve 801.06.1.V		-1.407				
34" Valve 801.09.3.V		-1.208				
Line 13 Valve 801.09.13.V		-1.321				
26" Valve 801.09.2.V		-1.334				
Rectifier #801				6.55	6.60	
MP 798.5						
26" Valve 798.57.2.V		-1.215				
MP 796.412						
18" Line		-1.167	-1.024			
26" Line		-1.149	-0.967			
20" Line		-1.357	-0.716			
34" Line		-1.3				
MP 792.10						
Joliette Station						
Rectifier 792				5.71	8.50	
Valve 792.07-13-BV		-1.419				
Valve 792.04-1-BV		-1.383				
Sump Tank		-1.327				
Valve 1-UDV-21		-1.358				
Pipe inside PCV Bldg.		-1.427				
MP 789.42						
20" Valve 789.39.1.V		-1.392				
34" Valve 789.35		-1.371				
18" Valve 789.42.13.V		-1.202				
MP 788.40						
Rectifier 789				7.33	17.10	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: LAKEHEAD PIPELINE

Date(s): 8-30-01

Unit: North Dakota

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 785.257						
36" Line		-1.512				
20" Line		-1.538	-0.686			
34" Line		-1.442				
18" Line		-1.363				
26" Line		-1.299	-0.929			
MP 781.068						
26" Line		-1.341				
18" Line		-1.389				
34" Line		-1.449				
20" Line		-1.543				
36" Line		-1.503				
MP 777.06						
26" Line		-1.419	-1.179			
18" Line		-1.428				
34" Line		-1.439				
20" Line		-1.511	-0.733			
36" Line		-1.481				
MP 775.729						
Rectifier 776				8.28	19.44	
MP 774.502						Last test stations before
34" Line		-1.469				the Canadian border.
18" Line		-1.482				
26" Line		-1.493				
20" Line		-1.485				
36" Line		-1.479				
MP 773.719 Canadian Border						

3/21/02

Phil:

Here is the documentation from Enbridge that we discussed recently.

I concurred some time ago, that I felt that there was some permanent reference cells that were defective under tankage in the Clearbrook terminal. I am of the same conclusion that Enbridge has arrived at. I believe that there is adequate Cathodic protection for the referenced tank. I also believe that during testing, that Enbridge was probably driving excess CP current. I support their decision to "turn down" the voltage they were driving during the testing.

The documentation was supplied to me at a meeting held in the Clearbrook terminal on March 6, 2002. Present at that meeting was Bill Chellew, Corrosion Tech, John Bissell, Corrosion Tech, Todd Gilseth, Coordinator and Lee Bakken, Terminal Manager, all Enbridge personnel. Also in attendance were David C. Smith and Keith Boswell, from Mears Inc., Enbridge's CP consultants.

You may add 1 AFO day for me. The meeting lasted about 2 hours.

I asked for a synopsis under the company letterhead. I received it today, over the signature of Bill Chellew. A copy is enclosed.

Any questions? You know where I may be found!

BH

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119 North 25th Street East
Superior, WI 54880
www.enbridgepartners.com

Bill C. Chellew
Corrosion Technician
Tel 715 394 1413
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bill.chellew@enbridge-us.com

ENBRIDGE™

March 7, 2002

Mr. Boyd Haugrose, Engineering Specialist
Minnesota Department of Public Safety
Office of Pipeline Safety
714 Lake Avenue, Suite 101A
Detroit Lakes, MN 56510

RE: Clearbrook Tank #64 CP Anomalies

Dear Mr. Haugrose:

Thank you for meeting with us at Clearbrook yesterday to allow us to present our test data and conclusions regarding the Clearbrook tankage CP issues that were raised during the 2001 audit. The following describes our test sequence and the rationale for the conclusions that have been drawn.

"Static" or "near static" potentials were established for Clearbrook Tanks 61, 62, 63, and 64 from two full months of depolarization (08/30/01 thru 10/29/01). As a result of this effort, we were able to prove compliance with the 100 mV negative shift criteria for Tanks 61, 62, and 63 by December 11, 2001. At that point, failures at two reference electrodes were still indicated for Tank 64.

David C. Smith from Mears and I returned to Clearbrook on 01/08/02 to conduct further testing on Tank #64. By this time, nearly another month of polarization had occurred. We began by collecting "ON" and "Instant Off" data at the existing rectifier output of 12 amps. Failure at only the #3 reference electrode was indicated at this time. We increased the rectifier output to 15 amps, returned the next day, and collected "ON" and "Instant Off" data again. At this point, failure was still indicated at the #3 reference electrode, but strangely, the indicated shift at the #8 reference electrode had diminished.

I returned again on 01/23/02 after approximately another two weeks of polarization at a 15 amp rectifier output. Again I set an interrupter and collected "ON" and "Instant Off" data. At this point, failures of the 100 mV criteria were indicated at reference electrodes #3 and #9. I then increased the rectifier output to 19.4 amps. I returned again the next day and again collected "ON" and "Instant Off" data. At this point, failures were indicated at reference electrodes #3 and #8.

I returned on 02/08/02, set an interrupter, and collected "ON" and "Instant Off" data again after approximately two weeks of polarization at a rectifier output of 19.4 amps. At this point, reference electrodes #8 and #9 indicated failures.

Throughout this entire exercise, reference electrodes 1, 5, and 10 have consistently shown polarization in the predicted direction as current output has been increased and as polarization time has been allowed. Others, including many where the 100 mV criteria is met, move erratically.

In an effort to explain this phenomenon, I'd like to offer the following speculations:
Comparing this arrangement with reference electrodes that have been installed along mainline pipe, it should be noted that mainline reference electrodes are located near the pipe and usually hundreds of feet from any groundbed elements. In the case of the tanks in question, the anode grids are located a mere foot or foot and a half beneath the tank floors, and the reference electrodes undoubtedly must sense some polarization of the groundbed as well as the polarization of the tank floor. I believe that the reference electrodes would normally be placed as near as practical to the tank floor and as far as possible from the anode grid. If, by some chance, reference electrodes were improperly located, unreliable reads would be all that would be available from them. I firmly believe that this is the case at Clearbrook's Tank #64. Other differences that likely have influence on reference electrode reads include a high resistivity sand backfill as opposed to native soil, bare steel floor as opposed to coated pipe, the presence of mill scale, and soil moisture levels that may be more variable.

We have been able to show respectable negative potential shifts (averaging in excess of 300 mV) on Tanks 61, 62, and 63 with average current densities of 0.436, 0.519, and 0.699 mA per square foot, respectively. At Tank #64, we finished our testing sequence at an average current density of 0.621 mA per square foot, and many of the reads had actually deteriorated at the higher rectifier output. Although nothing can be proven without dismantling Tank 64, I believe that our testing strongly supports the premise that a number of Tank #64 reference electrodes are either improperly located or otherwise defective. We have determined also that these reference electrodes are **NOT** removable and replaceable. I believe that we have produced justification here to declare Tank #64 reference electrodes #3, 8, and 9 to be defective and to adjust our Tank #64 cathodic protection on the basis of data obtained from the others. I truly believe that we were over driving this anode grid at the 19.5 amp rectifier output, and, with your concurrence yesterday, we reduced it by one tap setting to an output of 11.3 amps.

Sincerely,

William C. Chellew

William C. Chellew
Corrosion Technician

CC: Jay Johnson
John Sobojinski
Mark Sitek
Al Aleknavicius
Todd Gilseth
Randy Wilberg
Kimberly Harris
John Bissell
Keith Boswell - Mears
Lee Bakken

February 28, 2002

William C. Chellew
Corrosion Technician
Enbridge Energy Company, Inc.
Superior Region Office
119 North 25th Street East
Superior, WI 54880
Tel: 715-394-1413, Fax: 715-394-1405, www.enbridgepartners.com

Dear Mr. Chellew:

Thank you for considering the CerAnode PiggyBack Tank Bottom Anode System for the protection of your ASTs. We have hundreds of these systems in operation around the world.

Kevin Corey of Energy Economics requested that I send you a sample of the anode material we use for the PiggyBack System. I sent you our 1.5 mm and our 3.0 mm version yesterday for your evaluation. I also included an example of the very important connections used. All connections are performed at the factory except the connections to the terminals at the junction box. The anode material quoted to you by CerAnode through our distributor Energy Economics is the small 1.5 MM diameter anode wire. We also have the larger available for applications where it is warranted or if more conservatism is desired. We are, however, confident of the design as it stands with the 1.5 mm diameter anode wire assuming we have been given all of the appropriate design parameters. You may want to review these to be sure.

One of the email attachments is a printout of the design parameters for the 165 foot tanks. You will note, for instance, that we have used a design current density of 1 mA/ft2 for the 50-year design when in reality a tank bottom rarely ever requires more than 0.5 and more likely 0.2 to 0.3 when clean washed river sand is used and the criteria chosen is the 100 mV polarization shift. We have assumed clean sand.

We have also included a full brochure for your review. It explains the features and theory of the system and the details of the connection. Our connection is very high quality as you will observe. I do not believe you will find one better in this market.

Please call me if you have any questions and I will be happy to discuss them with you.

Sincerely,
Philip H. Chitty

PHChitty

General Manager
CerAnode Technologies Int'l.

Cc: Kevin Corey – Energy Economics Inc.

Tank 61 Static Testing / 100 mV Shift

Reference Point	Electrode Type	"OFF" 09/13/2001	"OFF" 09/20/2001	"OFF" 09/27/2001	"OFF" 10/04/2001	"OFF" 10/11/2001	"OFF" 10/29/2001	"ON" 12/11/2001	"I-OFF" 12/11/2001	Latest Shift
1	Cu / CuSO4	-0.143	-0.13	-0.119	-0.116	-0.109	-0.1	-0.72	-0.414	-0.314
2	Cu / CuSO4	-0.383	-0.292	-0.228	-0.205	-0.189	-0.166	-0.72	-0.455	-0.289
3	Cu / CuSO4	-0.132	-0.123	-0.114	-0.1	-0.09	-0.071	-0.689	-0.428	-0.357
4	Cu / CuSO4	-0.137	-0.136	-0.132	-0.131	-0.127	-0.119	-0.776	-0.471	-0.352
5	Cu / CuSO4	-0.128	-0.114	-0.103	-0.097	-0.091	-0.076	-0.798	-0.435	-0.359

Rect. 909H
Taps: A-2
E = 3.46
I = 11.1
0.436 mA/sf

Tank 62 Static Testing / 100 mV Shift

Reference Point	Electrode Type	"OFF" 09/13/2001	"OFF" 09/20/2001	"OFF" 09/27/2001	"OFF" 10/04/2001	"OFF" 10/11/2001	"OFF" 10/29/2001	"ON" 12/11/2001	"I-OFF" 12/11/2001	Latest Shift
1	Cu / CuSO4	-0.174	-0.156	-0.127	-0.115	-0.111	-0.087	-0.772	-0.498	-0.411
2	Cu / CuSO4	-0.45	-0.437	-0.428	-0.425	-0.421	-0.417	-0.702	-0.573	-0.156
3	Cu / CuSO4	-0.778	-0.766	-0.729	-0.697	-0.675	-0.529	-1.023	-0.814	-0.285
4	Cu / CuSO4	-0.513	-0.486	-0.387	-0.303	-0.285	-0.193	-0.93	-0.586	-0.393
5	Cu / CuSO4	-0.081	-0.072	-0.054	-0.049	-0.057	-0.038	-0.748	-0.435	-0.397

Rect. 909J
Taps: A-2
E = 3.58
I = 13.2
0.519 mA/sf

Tank 63 Static Testing / 100 mV Shift

Reference Point	Electrode Type	"OFF" 09/13/2001	"OFF" 09/20/2001	"OFF" 09/27/2001	"OFF" 10/04/2001	"OFF" 10/11/2001	"OFF" 10/29/2001	"ON" 12/11/2001	"I-OFF" 12/11/2001	Latest Shift
1	Zinc	0.92	0.95	0.979	0.995	1.009	1.026	0.476	0.689	-0.337
2	Zinc	0.737	0.762	0.807	0.822	0.857	0.948	0.126	0.429	-0.519
3	Zinc	0.287	0.299	0.316	0.317	0.328	0.349	-0.107	0.175	-0.174
4	Zinc	0.518	0.613	0.631	0.68	0.727	0.825	0.056	0.228	-0.597
5	Zinc	0.965	0.983	0.998	1.004	1.011	1.023	0.293	0.588	-0.435
6	Cu / CuSO4	-0.173	-0.155	-0.136	-0.128	-0.116	-0.093	-0.655	-0.418	-0.325
7	Cu / CuSO4	-0.463	-0.452	-0.42	-0.392	-0.353	-0.2	-0.874	-0.648	-0.448
8	Cu / CuSO4	-0.794	-0.792	-0.781	-0.783	-0.774	-0.755	-1.244	-0.983	-0.228
9	Cu / CuSO4	-0.291	-0.279	-0.274	-0.269	-0.254	-0.238	-1.001	-0.781	-0.543
10	Cu / CuSO4	-0.187	-0.165	-0.146	-0.136	-0.129	-0.116	-0.895	-0.502	-0.386

Rect. 909K
Taps: A-2
E = 4.2
I = 17.8
0.699 mA/sf

Tank 64 Static Testing / 100 mV Shift

Reference Point	Electrode Type	"OFF" 09/13/2001	"OFF" 09/20/2001	"OFF" 09/27/2001	"OFF" 10/04/2001	"OFF" 10/11/2001	"OFF" 10/29/2001	"ON" 12/11/2001	"I-OFF" 12/11/2001	Latest Shift
1	Zinc	0.816	0.853	0.899	0.938	0.951	1.002	0.563	0.626	-0.376
2	Zinc	0.27	0.281	0.288	0.295	0.302	0.31	0.087	0.148	-0.162
3	Zinc	0.305	0.305	0.309	0.312	0.316	0.322	0.291	0.39	[redacted]
4	Zinc	0.274	0.282	0.291	0.297	0.303	0.325	0.144	0.203	-0.122
5	Zinc	0.867	0.887	0.909	0.932	0.95	0.975	0.418	0.601	-0.374
6	Cu / CuSO4	-0.339	-0.304	-0.253	-0.207	-0.177	-0.124	-0.774	-0.621	-0.497
7	Cu / CuSO4	-0.814	-0.811	-0.811	-0.809	-0.806	-0.788	-0.986	-0.932	-0.144
8	Cu / CuSO4	-0.518	-0.52	-0.471	-0.454	-0.381	-0.432	-1.25	-0.583	-0.151
9	Cu / CuSO4	-0.832	-0.824	-0.813	-0.808	-0.809	-0.757	-0.935	-0.841	[redacted]
10	Cu / CuSO4	-0.251	-0.209	-0.177	-0.155	-0.138	-0.117	-0.7	-0.572	-0.455

Rect. 909L
Taps: A - 3
E = 3.6
I = 12
0.382 mA/sf

Tank 64 Static Testing / 100 mV Shift 01/08/02

Reference Point	Electrode Type	Depolarized 10/29/2001	909L Voltage 01/08/2002	909L ~~Voltage~~ AMPS 01/08/2002	"ON" 01/08/2002	"I-OFF" 01/08/2002	01/08/2002 Shift
1	Zinc	1.002	3.6	12	0.46	0.524	-0.478
2	Zinc	0.31	"	"	0.072	0.136	-0.174
3	Zinc	0.322	"	"	0.205	0.305	[redacted]
4	Zinc	0.325	"	"	0.124	0.184	-0.141
5	Zinc	0.975	"	"	0.39	0.582	-0.393
6	Cu / CuSO4	-0.124	"	"	-0.848	-0.675	-0.551
7	Cu / CuSO4	-0.788	"	"	-1.012	-0.951	-0.163
8	Cu / CuSO4	-0.432	"	"	-1.232	-0.547	-0.115
9	Cu / CuSO4	-0.757	"	"	-0.931	-0.864	-0.107
10	Cu / CuSO4	-0.117	"	"	-0.727	-0.593	-0.476
			0.382 mA/sq ft				

Tank 64 Static Testing / 100 mV Shift 01/09/02

Reference Point	Electrode Type	Depolarized 10/29/2001	909L Voltage 01/09/2002	909L Amps 01/09/2002	"ON" 01/09/2002	"I-OFF" 01/09/2002	01/09/2002 Shift
1	Zinc	1.002	4.45	15	0.395	0.49	-0.512
2	Zinc	0.31	"	"	0.035	0.122	-0.188
3	Zinc	0.322	"	"	0.152	0.287	[redacted]
4	Zinc	0.325	"	"	0.086	0.184	-0.141
5	Zinc	0.975	"	"	0.25	0.55	-0.425
6	Cu / CuSO4	-0.124	"	"	-0.948	-0.71	-0.586
7	Cu / CuSO4	-0.788	"	"	-1.06	-0.96	-0.172
8	Cu / CuSO4	-0.432	"	"	-1.495	-0.535	-0.103
9	Cu / CuSO4	-0.757	"	"	-1.01	-0.87	-0.113
10	Cu / CuSO4	-0.117	"	"	-0.815	-0.622	-0.505
			0.477 mA/sq ft				

Tank 64 Static Testing / 100 mV Shift 01/23/02

Reference Point	Electrode Type	Depolarized 10/29/2001	909L Voltage 01/23/2002	909L Amps 01/23/2002	"ON" 01/23/2002	"I-OFF" 01/23/2002	01/23/2002 Shift
1	Zinc	1.002	4.48**	14.7	0.318	0.413	-0.589
2	Zinc	0.31	"	"	0.026	0.118	-0.192
3	Zinc	0.322	"	"	0.132	0.267	[redacted]
4	Zinc	0.325	"	"	0.079	0.169	-0.156
5	Zinc	0.975	"	"	0.255	0.537	-0.438
6	Cu / CuSO4	-0.124	"	"	-1.001	-0.744	-0.62
7	Cu / CuSO4	-0.788	"	"	-1.086	-0.99	-0.202
8	Cu / CuSO4	-0.432	"	"	-1.544	-0.548	-0.116
9	Cu / CuSO4	-0.757	"	"	-0.972	-0.855	[redacted]
10	Cu / CuSO4	-0.117	"	"	-0.819	-0.634	-0.517
			0.468 mA/sq ft				

** Indicates Resister in DC Circuit

Tank 64 Static Testing / 100 mV Shift 01/24/02

Reference Point	Electrode Type	Depolarized 10/29/2001	909L Voltage 01/24/2002	909L Amps 01/24/2002	"ON" 01/24/2002	"I-OFF" 01/24/2002	01/24/2002 Shift
1	Zinc	1.002	5.34	19.4	0.253	0.398	-0.604
2	Zinc	0.31	"	"	-0.01	0.106	-0.204
3	Zinc	0.322	"	"	0.064	0.232	[redacted]
4	Zinc	0.325	"	"	0.03	0.143	-0.182
5	Zinc	0.975	"	"	0.15	0.511	-0.464
6	Cu / CuSO4	-0.124	"	"	-1.106	-0.782	-0.658
7	Cu / CuSO4	-0.788	"	"	-1.138	-1.013	-0.225
8	Cu / CuSO4	-0.432	"	"	-1.688	-0.486	[redacted]
9	Cu / CuSO4	-0.757	"	"	-1.058	-0.886	-0.129
10	Cu / CuSO4	-0.117	"	"	-0.893	-0.663	-0.546
			0.618 mA/sq ft				

Tank 64 Static Testing / 100 mV Shift 02/08/02

Reference Point	Electrode Type	Depolarized 10/29/2001	909L Voltage 02/08/2002	909L Amps 02/08/2002	"ON" 02/08/2002	"I-OFF" 02/08/2002	02/08/2002 Shift
1	Zinc	1.002	5.45	19.5	0.16	0.318	-0.684
2	Zinc	0.31	"	"	-0.012	0.13	-0.18
3	Zinc	0.322	"	"	0.045	0.218	-0.104
4	Zinc	0.325	"	"	0.016	0.182	-0.143
5	Zinc	0.975	"	"	0.034	0.497	-0.478
6	Cu / CuSO4	-0.124	"	"	-1.155	-0.784	-0.66
7	Cu / CuSO4	-0.788	"	"	-1.151	-0.992	-0.204
8	Cu / CuSO4	-0.432	"	"	-1.605	-0.352	[redacted]
9	Cu / CuSO4	-0.757	"	"	-0.897	-0.711	[redacted]
10	Cu / CuSO4	-0.117	"	"	-0.931	-0.665	-0.548
			0.621 mA/sq ft				

Tank 64 Supporting Data 02/08/02

(+) Shunts	Amps
1	3.4
2	3.6
3	4.7
4	3.8
5	4

Notes

1. Reference points 8 & 9 are now giving Instant-Off reads that are less negative than static values. This should not be possible.

2. Two weeks of additional polarization at the above rectifier setting have resulted in reference electrodes 2,4,7,8, & 9 showing LESS negative shift than what was recorded previously.

3. Reference electrode #8, in particular, exhibits unusual behavior. Instead of becoming increasingly negative during the course of the interrupter "ON" cycle, the initial read of -1.730 diminished to -1.605. During the course of the "OFF" cycle, an Instant-Off of -0.352 was read. The reads then proceeded to become MORE negative to a read of -0.492 before the interrupter cycled the rectifier back on.

Bill C Chellew

02/11/2002 11:13 AM

To: Jay A Johnson/LPL
cc: keith.boswell@mears.net, Al V Aleknavicius/LPL, John Bissell/US/Enbridge, Kimberly J Harris/LPL, Mark S Sitek/LPL, Todd G Gilseth/LPL, Randy E Wilberg/LPL, Lee H Bakken/LPL
Subject: Clearbrook Tank 64 - 02/08/02 Data

File Database: File:
Would you like the recipient to view the FILING info? ○ Yes ● No

Jay,

"Static" or "near static" potentials were established for Clearbrook Tanks 61, 62, 63, and 64 as a result of two full months of depolarization (08/30/01 thru 10/29/01). As a result of this effort, we were able to prove compliance with the 100 mV negative shift criteria for Tanks 61, 62, and 63 by December 11, 2001. At that point, failures at two reference electrodes were still indicated for Tank 64.

David C. Smith from Mears and I returned to Clearbrook on 01/08/02 to conduct further testing. By this time, nearly another month of polarization had occurred. We began by collecting "ON" and "Instant Off" data at the existing rectifier output of 12 amps. Failure at only the #3 reference electrode was indicated. We increased the rectifier output to 15 amps, returned the next day, and collected "ON" and "Instant Off" data again. At this point, failure was still indicated at the #3 reference electrode, but strangely, the indicated shift at the #8 reference electrode had diminished.

I returned again on 01/23/02 after approximately another two weeks of polarization at a 15 amp rectifier output. Again I set an interrupter and collected "ON" and "Instant Off" data. At this point, failures of the 100 mV criteria were indicated at reference electrodes #3 and #9. I then increased the rectifier output to 19.4 amps. I returned again the next day and again collected "ON" and "Instant Off" data. At this point, failures were indicated at reference electrodes #3 and #8.

I returned again on 02/08/02, set an interrupter, and collected "ON" and "Instant Off" data again, after approximately two weeks of polarization at a rectifier output of 19.4 amps. At this point, reference electrodes #8 and #9 indicated failures.

Throughout this entire exercise, reference electrodes 1, 5, and 10 have consistently shown polarization in the predicted direction as current output has been increased and as polarization time has been allowed. Others, including many where the 100 mV criteria is met, move erratically.

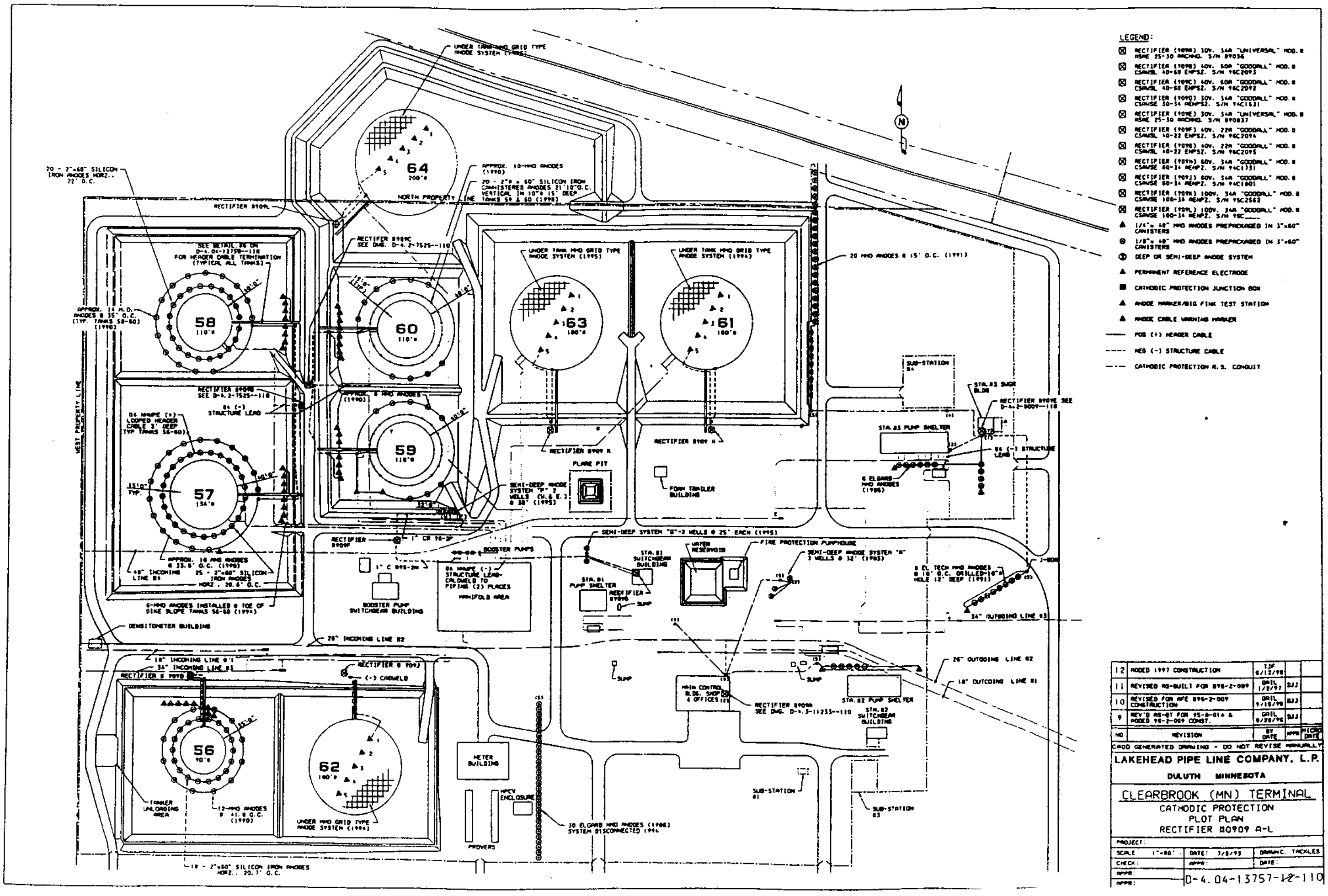
In an effort to explain this phenomenon, I'd like to offer the following speculations: Comparing this arrangement with reference electrodes that have been installed along mainline pipe, it should be noted that mainline reference electrodes are located near the pipe and usually hundreds of feet from any groundbed elements. In the case of the tanks in question, the anode grids are located a mere foot or foot and a half beneath the tank floors, and the reference electrodes undoubtedly must sense some polarization of the groundbed as well as the polarization of the tank floor. I believe that the reference electrodes would normally be placed as near as practical to the tank floor and as far as possible from the anode grid. If, by some chance, reference electrodes were improperly located, unreliable reads would be all that would be available from them. I firmly believe that this is the case at Clearbrook's Tank #64.

We have been able to show respectable average potential shifts (all in excess of -300 mV) on Tanks 61, 62, and 63 with average current densities of 0.436, 0.519, and 0.699 mA per square foot, respectively. At Tank #64, we are now at an average current density of 0.621 mA per square foot and many of the reads have actually deteriorated at the higher rectifier output. Although nothing can be proven without dismantling Tank 64, I believe that our testing strongly supports the premise that a number of Tank #64 reference electrodes are either improperly located or otherwise defective. We have determined also that these reference electrodes are NOT removable and replaceable. I hope that we have produced justification here to declare Tank #64 reference electrodes #3, 8, and 9 to be defective and to adjust our Tank #64 cathodic protection on the basis of data obtained from the others. I truly believe that we are currently over driving this anode grid and that we are depleting it at an unnecessarily rapid rate.

Attached are the files on the test data.

Clearbrooktank64static.x Clearbrooktankstatic1.x

BC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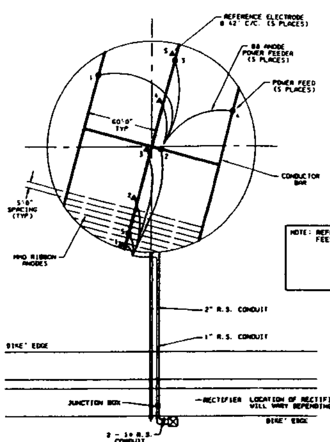
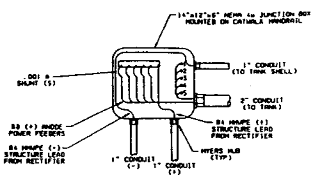
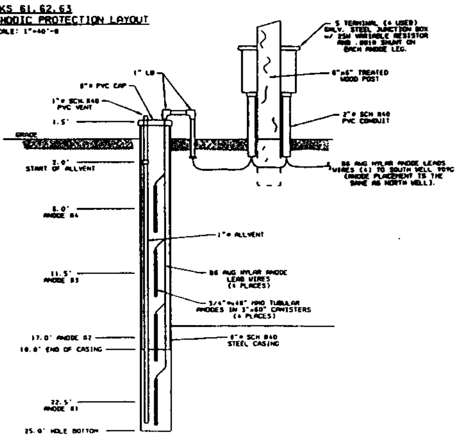
RECTIFIER (909A) 30V. 34A "UNIVERSAL" MOD. # ASAE 25-30 ARCHNO. S/N 89036
RECTIFIER (909B) 40V. 60A "GOODALL" MOD. # CSAVSL 40-60 ENPSZ. S/N 96C2093
RECTIFIER (909C) 40V. 60A "GOODALL" MOD. # CSAVSL 40-60 ENPSZ. S/N 96C2092
RECTIFIER (909D) 30V. 34A "GOODALL" MOD. # CSAVSE 30-34 AENPSZ. S/N 94C1631
RECTIFIER (909E) 30V. 34A "UNIVERSAL" MOD. # ASAE 25-30 ARCHNO. S/N 890037
RECTIFIER (909F) 40V. 22A "GOODALL" MOD. # CSAVSL 40-22 ENPSZ. S/N 96C2094
RECTIFIER (909G) 40V. 22A "GOODALL" MOD. # CSAVSL 40-22 ENPSZ. S/N 96C2095
RECTIFIER (909H) 60V. 34A "GOODALL" MOD. # CSAVSE 60-34 AENPZ. S/N 94C1731
RECTIFIER (909J) 60V. 34A "GOODALL" MOD. # CSAVSE 60-34 AENPZ. S/N 94C1601
RECTIFIER (909K) 100V. 34A "GOODALL" MOD. # CSAVSE 100-34 AENPZ. S/N 95C2562
RECTIFIER (909L) 100V. 34A "GOODALL" MOD. # CSAVSE 100-34 AENPZ. S/N 98C___
1/4"x 60" MMO ANODES PREPACKAGED IN 3"x60" CANISTERS
1/8"x 60" MMO ANODES PREPACKAGED IN 3"x60" CANISTERS
DEEP OR SEMI-DEEP ANODE SYSTEM
PERMANENT REFERENCE ELECTRODE
CATHODIC PROTECTION JUNCTION BOX
ANODE MARKER/BIG FINK TEST STATION
ANODE CABLE WARNING MARKER
POS (+) HEADER CABLE
NEG (-) STRUCTURE CABLE
CATHODIC PROTECTION R.S. CONDUIT
64
58
60
63
61
59
57
56
62
NORTH PROPERTY LINE
WEST PROPERTY LINE
FLARE PIT
FOAM TRAILER BUILDING
SUB-STATION
STA.83 PUMP SHELTER
WATER RESERVOIR
FIRE PROTECTION PUMPHOUSE
STA.81 PUMP SHELTER
BOOSTER PUMPS
BOOSTER PUMP SWITCHGEAR BUILDING
MANIFOLD AREA
DENSITOMETER BUILDING
MAIN CONTROL BLDG. SHOP & OFFICES
STA.82 PUMP SHELTER
METER BUILDING
PROVERS
TANKER UNLOADING AREA
26" INCOMING LINE #2
18" INCOMING LINE #1
34" INCOMING LINE #3
26" OUTGOING LINE #2
18" OUTGOING LINE #1
34" OUTGOING LINE #3
12	ADDED 1997 CONSTRUCTION	TJF 6/12/98		
11	REVISED AS-BUILT FOR 896-2-009	GAIL 1/2/97	DJJ	
10	REVISED FOR AFE 896-2-009 CONSTRUCTION	GAIL 9/18/96	DJJ	
9	REV'D AS-BT FOR 95-8-014 & ADDED 96-2-009 CONST.	GAIL 8/28/96	DJJ	
NO	REVISION	BY DATE	APPR	MICRO DATE
CADD GENERATED DRAWING - DO NOT REVISE MANUALLY
LAKEHEAD PIPE LINE COMPANY, L.P.
DULUTH MINNESOTA
CLEARBROOK (MN) TERMINAL
CATHODIC PROTECTION
PLOT PLAN
RECTIFIER #0909 A-L
PROJECT:
SCALE 1"=80'
DATE: 7/8/93
DRAWN: C. TACKLES
CHECK:
APPR:
DATE:
APPR:
APPR:
D-4.04-13757-12-110



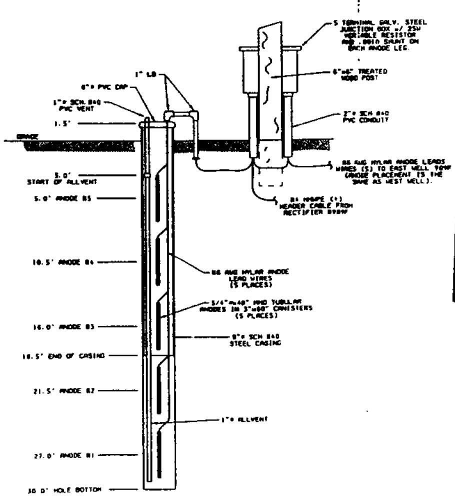
TANKS 61, 62, 63
TANK BOTTOM CATHODIC PROTECTION LAYOUT



TANK JUNCTION BOX DETAIL



25' SEMI-DEEP ANODE SYSTEM '909G'
NORTH WELL DETAIL - VIEWED FROM EAST



30' SEMI-DEEP ANODE SYSTEM '909F'
WEST WELL DETAIL - VIEWED FROM NORTH

NO	REVISION	BY DATE	APPR	MICRO DATE

CADD GENERATED DRAWING - DO NOT REVISE MANUALLY

LAKEHEAD PIPE LINE COMPANY, L.P.
DULUTH MINNESOTA

CLEARBROOK (MN) TERMINAL
CATHODIC PROTECTION
INSTALLATION DETAILS
SHEET 1 OF 1

PROJECT:		
SCALE: AS NOTED	DATE: 10/19/96	DRAWN: T. FAUSZ
CHECK:	APPR:	DATE

JOB TITLE: 2 - 200' AST Grid Systems

CUSTOMER: Lakehead Pipe Line

JOB SITE: Superior, Wisconsin Terminal **DATE:** 01-Feb-00

JOB NO: C38001 **ENGINEER:** WCB **FILE:** Construction

TANK 30 S/S POTENTIAL DATA

TEST NO.	STRUCTURE/LOCATION	S/S POTENTIAL (VOLTS)				REMARKS
		Static	ON	I-Off	Δ	
	Permanent Reference Cells Underneath the Tank Bottom					
1a.	Zinc PRC	0.978	-1.4488	0.658	-0.32	
1b.	Copper/CopperSulfate PRC	-0.158	-2.45	-0.452	-0.294	
2a.	Zinc PRC	0.975	-1.61	0.641	-0.334	
2b.	Copper/CopperSulfate PRC	-0.173	-2.898	-0.602	-0.429	
3a.	Zinc PRC	0.924	-3.009	0.452	-0.472	
3b.	Copper/CopperSulfate PRC	-0.216	-4.2	-0.836	-0.62	
4a.	Zinc PRC	0.97	-2.221	0.397	-0.573	
4b.	Copper/CopperSulfate PRC	-0.175	-3.982	-0.797	-0.622	
5a.	Zinc PRC	0.917	-2.736	0.482	-0.435	
5b.	Copper/CopperSulfate PRC	-0.23	-2.978	-0.789	-0.559	
6a.	Zinc PRC	0.974	-2.883	0.489	-0.485	
6b.	Copper/CopperSulfate PRC	-0.101	-4.16	-0.698	-0.597	
7a.	Zinc PRC	0.878	-3.447	0.477	-0.401	
7b.	Copper/CopperSulfate PRC	-0.248	-4.78	-0.718	-0.47	
8a.	Zinc PRC	0.935	-1.42	0.741	-0.194	
8b	Copper/CopperSulfate PRC	-0.215	-2.35	-0.456	-0.241	
9a	Zinc PRC	0.953	-1.499	0.704	-0.249	
9b	Copper/CopperSulfate PRC	-0.184	-2.489	-0.489	-0.305	
10a.	Zinc PRC	0.989	-0.284	0.732	-0.257	
10b.	Copper/CopperSulfate PRC	-0.137	-1.318	-0.427	-0.29	
	ABBREVIATIONS & REMARKS					
	S/S = Structure-to-soil					
	PRC = Permanent Reference Cell					
	Static = S/S Without Cathodic Protection					
	ON = Current Applied					
	I-Off = DC Current Intercupted					

JOB TITLE: 2 - 200' AST Grid Systems

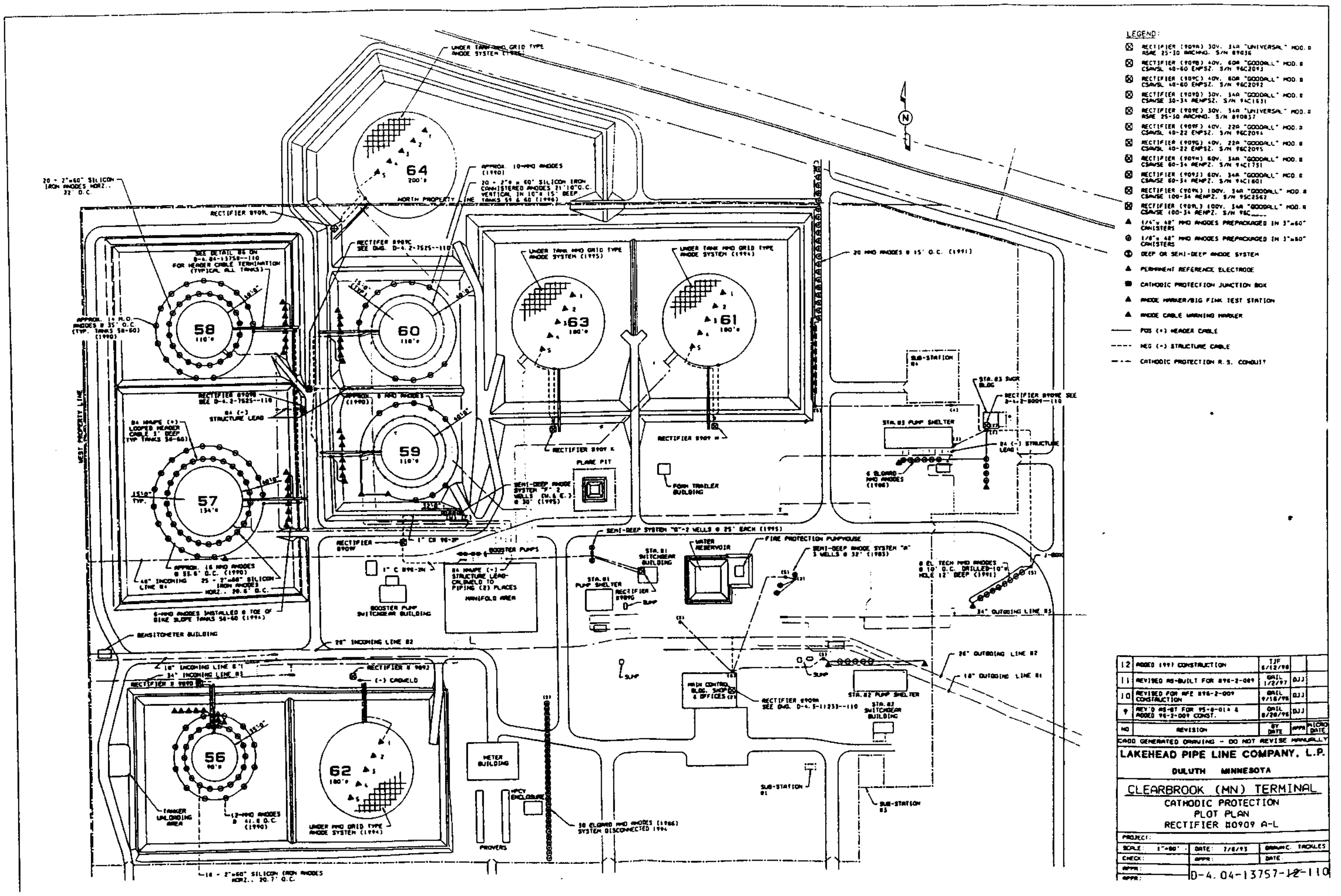
CUSTOMER: Lakehead Pipe Line

JOB SITE: Superior, Wisconsin Terminal **DATE:** 01-Feb-00

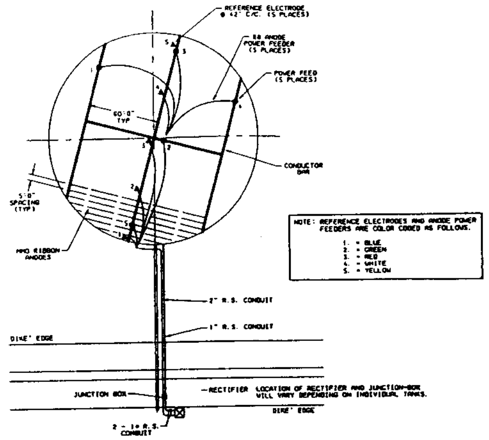
JOB NO: C38001 **ENGINEER:** WCB **FILE:** Construction

TANK 31 S/S POTENTIAL DATA

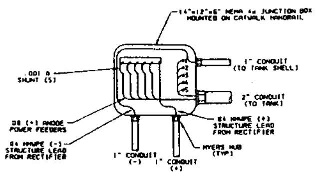
TEST NO.	STRUCTURE/LOCATION	S/S POTENTIAL (-VOLTS)				REMARKS
		Static	ON	I-Off	Δ	
	Permanent Reference Cells Underneath the Tank Bottom					
1a.	Zinc PRC	0.909	-0.718	0.502	-0.407	
1b.	Copper/CopperSulfate PRC	-0.223	-2.475	-0.694	-0.471	
2a.	Zinc PRC	0.938	-1.187	0.604	-0.334	
2b.	Copper/CopperSulfate PRC	-0.203	-2.157	-0.596	-0.393	
3a.	Zinc PRC	0.916	-0.695	0.614	-0.302	
3b.	Copper/CopperSulfate PRC	-0.228	-1.444	-0.502	-0.274	
4a.	Zinc PRC	0.958	0.266	0.672	-0.286	
4b.	Copper/CopperSulfate PRC	-0.161	-0.809	-0.452	-0.291	
5a.	Zinc PRC	1.03	0.185	0.792	-0.238	
5b.	Copper/CopperSulfate PRC	-0.105	-1.149	-0.398	-0.293	
6a.	Zinc PRC	0.943	-0.389	0.586	-0.357	
6b.	Copper/CopperSulfate PRC	-0.195	-1.588	-0.614	-0.419	
7a.	Zinc PRC	0.946	-1.643	0.525	-0.421	
7b.	Copper/CopperSulfate PRC	-0.183	-3.121	-0.659	-0.476	
8a.	Zinc PRC	0.952	-0.284	0.645	-0.307	
8b	Copper/CopperSulfate PRC	-0.217	-1.978	-0.592	-0.375	
9a	Zinc PRC	0.837	-0.071	0.657	-0.18	
9b	Copper/CopperSulfate PRC	-0.183	-1.281	-0.597	-0.414	
10a.	Zinc PRC	0.973	-0.131	0.587	-0.386	
10b.	Copper/CopperSulfate PRC	-0.268	-1.103	-0.448	-0.18	
	ABBREVIATIONS & REMARKS					
	S/S = Structure-to-soil					
	PRC = Permanent Reference Cell					
	Static = S/S Without Cathodic Protection					
	ON = Current Applied					
	I-Off = DC Current Interupted					



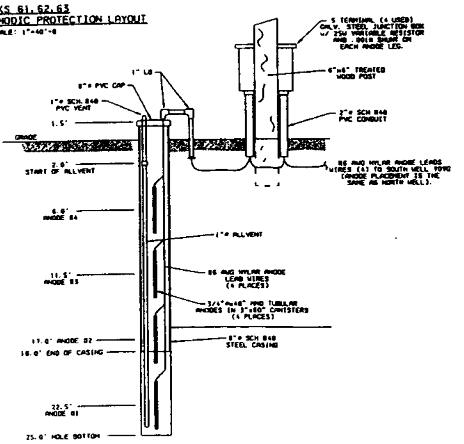
LEGEND:
RECTIFIER (909A) 30V. 34A "UNIVERSAL" MOD. # RSAE 25-30 ARCHNO. S/N 89036
RECTIFIER (909B) 40V. 60A "GOODALL" MOD. # CSAVSL 40-60 ENPSZ. S/N 96C2093
RECTIFIER (909C) 40V. 60A "GOODALL" MOD. # CSAVSL 40-60 ENPSZ. S/N 96C2092
RECTIFIER (909D) 30V. 34A "GOODALL" MOD. # CSAVSE 30-34 AENPSZ. S/N 94C1631
RECTIFIER (909E) 30V. 34A "UNIVERSAL" MOD. # RSAE 25-30 ARCHNO. S/N 890837
RECTIFIER (909F) 40V. 22A "GOODALL" MOD. # CSAVSL 40-22 ENPSZ. S/N 96C2094
RECTIFIER (909G) 40V. 22A "GOODALL" MOD. # CSAVSL 40-22 ENPSZ. S/N 96C2095
RECTIFIER (909H) 60V. 34A "GOODALL" MOD. # CSAVSE 60-34 AENPZ. S/N 94C1751
RECTIFIER (909J) 60V. 34A "GOODALL" MOD. # CSAVSE 60-34 AENPZ. S/N 94C1801
RECTIFIER (909K) 100V. 34A "GOODALL" MOD. # CSAVSE 100-34 AENPZ. S/N 95C2562
RECTIFIER (909L) 100V. 34A "GOODALL" MOD. # CSAVSE 100-34 AENPZ. S/N 96C____
DEEP OR SEMI-DEEP ANODE SYSTEM
PERMANENT REFERENCE ELECTRODE
CATHODIC PROTECTION JUNCTION BOX
ANODE CABLE WARNING MARKER
POS (+) HEADER CABLE
NEG (-) STRUCTURE CABLE
CATHODIC PROTECTION R.S. CONDUIT
12 ADDED 1997 CONSTRUCTION
11 REVISED AS-BUILT FOR #96-2-009
10 REVISED FOR AFE #96-2-009 CONSTRUCTION
9 REV'D AS-BT FOR 95-8-014 & ADDED 96-2-009 CONST.
NO REVISION BY DATE APPR MICRO DATE
CADD GENERATED DRAWING - DO NOT REVISE MANUALLY
LAKEHEAD PIPE LINE COMPANY, L.P.
DULUTH MINNESOTA
CLEARBROOK (MN) TERMINAL
CATHODIC PROTECTION
PLOT PLAN
RECTIFIER #0909 A-L
PROJECT:
SCALE:
CHECK:
APPR:
D-4.04-13757-12-110



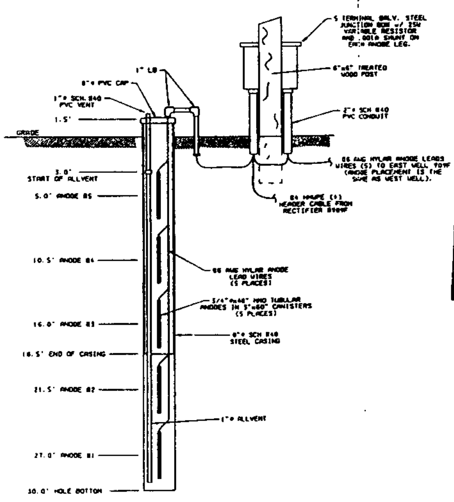
TANKS 61, 62, 63
TANK BOTTOM CATHODIC PROTECTION LAYOUT
SCALE: 1"=40'-0



TANK JUNCTION BOX DETAIL
SCALE: 1-1/2"=12"



25' SEMI-DEEP ANODE SYSTEM '909G'
NORTH WELL DETAIL - VIEWED FROM EAST



30' SEMI-DEEP ANODE SYSTEM '909F'
WEST WELL DETAIL - VIEWED FROM NORTH

NO	REVISION	BY DATE	APPR	MICRO DATE

CADD GENERATED DRAWING - DO NOT REVISE MANUALLY

LAKEHEAD PIPE LINE COMPANY, L.P.
DULUTH MINNESOTA

CLEARBROOK (MN) TERMINAL
CATHODIC PROTECTION
INSTALLATION DETAILS
SHEET 1 OF 1

PROJECT:
SCALE: AS NOTED | DATE: 10/19/98 | DRAWN: T. FAUST
CHECK: | APPR: | DATE:

Inspection Summary

U.S. Department of Transportation

Research and Special Programs Administration

Central Region Office

Office of Pipeline Safety

To: Region Director

Date: 4/17/02

p.a.

From: Phil Archuletta, Staff Engineer

Company Inspected: LAKEHEAD PIPE LINE CO INC

Operator: LAKEHEAD PIPE LINE CO INC

Type of Service: Interstate Liquid

Inter-Regional System:	System Description	Inspection I.D.
CRUDE SYSTEM 3	Various size lines from Superior, WI southeast to Chicago and then northeast to the Canadian/US border, near Marysville, MI (in the CE region the system includes Unit #295: Bay City, Unit #1282: Griffith, Unit #134: Fort Atkinson, & Unit #132: Superior)	93250 (Headquarters) 91733 (Field) 91734 (Field) 91790 (Field) 91792 (Field)

Dates of Inspection: 5/7/01 - 5/12/01 (Headquarters); 6/11 - 6/22 (Field)

Location: Duluth, MN (HQ NHIF), Duluth, MN (records); Bay City, MI (records); Griffith, IN (records); Fort Atkinson, WI (PLM records); Superior, WI (records); States of Michigan, Indiana, Illinois and Wisconsin (field facilities)

Facilities Inspected: Phil Archuletta and David Barrett from CE OPS conducted a CE-regional system inspection of Lakehead Pipeline Company's Crude System #3. The inspection was conducted using the "New High Impact Form (NHIF)" inspection form. All documents and records requested were presented and were satisfactory with the exception of items noted below under "Deficiencies Found."

Lakehead Pipe Line's facilities for this unit consist of the following:

- Approx. 286 miles of 30" from the US/Canada border to Griffith, IN
- Approx. 465 miles of 34" from Griffith, IN to Superior, WI
- Approx. 461 miles of 24" from Mokena, IL to Superior, WI
- Approx. 30 miles of 16" from Stockbridge, MI to Freedom Junction, MI

- 33 Pump stations located across MI, IN, IL and WI
- Breakout tanks at Griffith, IN; Hartsdale, IL; Stockbridge, MI and Superior, WI.

The actual physical facilities inspected included:

- 16" Line from Stockbridge, MI to Freedom Junction, MI
- 30" Line from New Carlisle, IN to Griffith, IN
- 24" Line from Mokena, IL to Superior, WI
- 34" Line from Griffith, IN to Superior, WI
- 33 Pump stations located across MI, IN, IL and WI
- Breakout tanks at Griffith, IN; Hartsdale, IL; Stockbridge, MI and Superior, WI.

A number of stops were made at valve settings, pump stations and points along the pipeline segments where C/P readings could be taken.

Persons Interviewed:

Refer to page 1 of the attached "High Impact" form for a listing of persons interviewed.

Deficiencies Found:

Lakehead Pipe Line's O&M Manuals were not evaluated. This operator was scheduled in 2001 for an inspection of several systems and the O&M Manuals were reviewed at the operator's headquarters in conjunction with the headquarters portion of the system inspections.

A review of Lakehead Pipe Line's records and field facilities identified the following deficiencies:

Headquarters Issues:

A. Notice of Amendment Items:

1. § 195.401 (b) General requirements.

Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(a) LPL procedures need revision to include verbage about including first discovery reports from all sources such as the public, employees, contractors, etc. and not just reports made to LPL's Control Center.

(b) LPL has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of LPL's pipeline systems, especially with regard to internal corrosion control procedures and remedial actions taken. However, LPL has not formalized the process by inclusion of specific verbage in LPL's O & M manual.

2. § 195.402 Procedural manual for operations, maintenance, and emergencies.

Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

LPL procedures need revision to include verbage about what LPL does for analysis and investigation of abnormal operating events to prevent re-occurrences of the events.

3. § 195.405 Protection against ignitions and safe access/egress involving floating roofs.

After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API Recommended Practice 2003, unless the operator notes in the procedural manual (§195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2003 is not necessary for the safety of a particular breakout tank.

LPL procedures need specific reference to industry standard API 2003.

4. § 195.420 Valve maintenance.

Each operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

LPL's procedures on valve inspections are confusing in that the procedures could be interpreted to mean that valve inspections are only done once per calendar year, when in fact, LPL inspects valves twice per calendar year per code requirements. The procedures need clarification so that there is no doubt that valves are to be inspected twice per calendar year. LPL did have one valve inspection interval that was exceeded due to flooding and it was suggested to LPL that comments regarding unusual conditions affecting inspections should be added to the valve inspection record.

5. § 195.432 Breakout tanks.

Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks. LPL procedures need revision to include verbage on what the corrective action process is if problems are found during any breakout tank inspection. LPL should implement a method to address conclusions and recommendations made during a tank inspection, and the status of corrective actions.

.432(b) LPL procedures need specific verbage on what items to look for during tank inspections as found in Section 4 of API 653.

.432(c) LPL needs procedures to inspect breakout tanks built to API 2510 according to Sec. 6 of API 510.

Field Issues:

During the federal portion of the field inspection, it was discovered that some signs displayed a telephone number which when called should have automatically forwarded the call to LPL's main Control Center. However, at the time of the inspection, the calls were not being automatically forwarded as intended. LPL investigated the problem and the situation has been corrected so that all calls are now forwarded to LPL's main Control Center. Since LPL has now had a merger/re-organization, LPL (now Enbridge Energy Partners, Inc.) will be replacing all signs along their ROW with new signs displaying one appropriate contact number.

B. Letter of Concern Items:

1. § 195.401 (b) General requirements.

Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(a) During the field inspection it was observed LPL's facilities had inadequate atmospheric protection at the following locations:

(1) MP 465.500 Griffith Station - Clean & re-coat pipe at the ground interfaces on the suction and discharge sides of each pump unit

(2) MP 341.351 (Line 6A) Walworth Station - Clean & re-coat pipe at the ground interfaces on the pipe inside the pressure control valve building.

(b) During the field inspection it was observed there were low P/S potentials at the following location:

MP 500.137 Forrester Rd. - Low CP potentials:
Line 6B: -0.820
Line 6B Loop: -0.836

(c) During the field inspection it was observed there is a possible shorted casing at the following location:

MP 63.348 (Line 6A) - Possible casing problem indicated by CP potentials. LPL plans additional testing and investigation.

(d) During the field inspection it was observed that rectifiers were not operative at the following locations:

(1) MP 432.428 Parker Rd. - Rectifier C433 was not operative. LPL suspects that the rectifier was hit by lightning and will do additional testing and repair as needed

(2) MP 173.300 Marshfield Station - Rectifier C173A was not operative. LPL suspects that the rectifier was hit by lightning and will do additional testing and repair as needed.

(e) During the field inspection it was observed that there is a possible rectifier problem at the following location:

MP 30.900 - The output for rectifier 031 had dropped from the last time the rectifier was checked. LPL suspects that the rectifier may have a bad diode. LPL will do additional testing and repair as needed.

(f) During the field inspection it was observed that pressure recording procedures need improvement at the following locations:

(1) MP 148.541 Owen Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3

(2) MP 135.555 Lublin Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3

(3) MP 99.250 Ladysmith Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3. There was a change in the labels that identify which pressures are being recorded in June, 1999. All charts stored prior to June, 1999 should be identified when the change occurred.

2. § 195.404 Maps and Records.

Each operator shall maintain current maps and records of its pipeline systems........etc.

Bay City: Records - Need to add the location of pressure transmitters on Dwg. D-17-3.04-00099-9-581 (Line 17) at the Oregon metering and Segment "E" areas. Need to add these locations to the mechanical drawings also.

3. § 195.422 Pipeline repairs.

No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

Fort Atkinson: Records - Documents for three joints of emergency stock pipe stored at Fort Atkinson were inadequately marked to specifically track these joints to the hydrostatic test reports kept at Fort Atkinson. LPL decided to scrap these three joints and label the joints as "NOT TESTED".

C. Notice of Probable Violation and Proposed Civil Penalty Items:

1. § 195.310 Records.

§ 195.310(b) The record required by paragraph (a) of this section must include:

§ 195.310(b)(9) Where elevation differences in the section under test exceed 100 feet, a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

The pressure test records for Line #17 (Stockbridge, MI to Freedom Junction, MI) did not contain a profile of the line although there are elevation differences that exceed 100 feet along the route for Line #17.

2. § 195.432 Inspection of in-service breakout tanks.

§ 195.432(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.

During the records review at Bay City, MI it was observed that Lakehead Pipeline did not have documentation for annual tank inspections for the Stockbridge, MI station for the year 2000.

D. Notice of Probable Violation and Proposed Compliance Order Items:

§ 195.401 (b) General requirements.

§ 195.401(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

During the field inspection it was observed that the view of LPL's right-of-way was obstructed at the following locations:

a. MP 515.100 (Line 6B) - on the east side of road.

b. MP 383.090 (Line 6A) Dundee Station - due north and south from the mainline valve located outside the station fencing.

Conclusions/Recommendations:

Lakehead Pipeline has submitted documentation regarding action taken on the following items under paragraph A (copies of documentation are attached):

Item 1.(a) - Copy of intended revision (2 sheets) to Procedure"Notification of Safety Concern". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item.

Item 1.(b) - Copy of intended revision to Procedure 08-02-01, "Corrosion Control"; page 3 of 9 - "Monitoring". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 2. - Copy of intended revision to Procedure "Abnormal Operation Procedure Review Process". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 3. - Copy of intended revision to Procedure 09-01-01, "Overview of Tank Maintenance"; page 2 of 3. LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 4. - Copy of intended revision to Procedure 03-02-01, "Right-Of-Way Inspections"; page 5 of 5 - "Valve Inspections". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 5. [for .432(b)] - Copy of intended revision to Procedure 09-02-02, "Tank Inspections"; page 2 of 7 - "Records - Routine Inspections - Monthly". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Item 5. [for .432(c)] - Copy of intended revision to Procedure 09-02-02, "Tank Inspections"; page 1 of 7 - "Requirements - Inspection Frequency". LPL has not submitted the actual final revised procedure. Recommend that LPL be issued a Notice of Amendment for this item..

Lakehead Pipeline has submitted documentation stating that corrective action has been completed on the following items under paragraph B (copies of documentation are attached):

Item 1.(a)(1) - "Lakehead Pipeline Inspection Issues", Item 2.C (recommend Letter of Concern)

Item 1.(a)(2) - "Lakehead Pipeline Inspection Issues", Item 2.F (recommend Letter of Concern)

Item 1.(b) - E-mail dated 08-27-01 (recommend Letter of Concern)

Item 1.(c) - "Lakehead Pipeline Inspection Issues", Item 2.K (recommend Letter of Concern)

Item 1.(d)(1) - "Lakehead Pipeline Inspection Issues", Item 2.D (recommend Letter of Concern)

Item 1.(d)(2) - "Lakehead Pipeline Inspection Issues", Item 2.G (recommend Letter of Concern)

Item 1.(e) - "Lakehead Pipeline Inspection Issues", Item 2.L (recommend Letter of Concern)

Item 1.(f)(1) - "Lakehead Pipeline Inspection Issues", Item 2.H (recommend Letter of Concern)

Item 1.(f)(2) - "Lakehead Pipeline Inspection Issues", Item 2.I (recommend Letter of Concern)

Item 1.(f)(3) - "Lakehead Pipeline Inspection Issues", Item 2.J (recommend Letter of Concern)

Item 2. - "Lakehead Pipeline Inspection Issues", Item 1.1 (recommend Letter of Concern)

Item 3. - "Lakehead Pipeline Inspection Issues", Item 1.3 (recommend Letter of Concern)

It is recommended that Lakehead Pipe Line be issued a Notice of Probable Violation & Proposed Civil Penalty for all items listed under paragraph C.

It is recommended that Lakehead Pipe Line be issued a Notice of Probable Violation & Proposed Compliance Order for all items listed under paragraph D.

Lakehead Pipeline Inspection Issues
For the Inspection Period 06/11/01 through 06/22/01

1. Lakehead Records Inspection: 06/11/01 through 06/22/01

    1. Bay City: Records - Need to add the location of pressure transmitters on Dwg. D-17-3.04-00099-9-581 (Line 17) at the Oregon metering and Segment "E" areas. Need to add these locations to the mechanical drawings also.

The pressure transmitter locations have been added to the Flow Diagram and piping drawings with copies shipped to the site the week of October 8, 2001.

    2. Bay City: Records - Tank inspection records for the Stockbridge, MI station were missing for the year 2000.

This item is currently under investigation by our Operations Services group

    3. Fort Atkinson: Records - Documents for three joints of emergency stock pipe stored at Fort Atkinson were inadequately marked to specifically track these joints to the hydrostatic test reports kept at Fort Atkinson. LPL decided to scrape these three joints and label the joints as "NOT TESTED".

The pipe joints referenced have been clearly labeled as "Not Tested."

2. Lakehead Field Inspection: 06/11/01 through 06/22/01

A. MP 515.100 (Line 6B) - Right-of-way needs clearing on the east side.

The area in question was identified as in "marginal" need of brushing, and is scheduled to be cleared by no later than the week of Oct. 15th.

B. MP 500.137 Forrester Rd. - Low CP potentials:
Line 6B: -0.820
Line 6B Loop: -0.836
Note: LPL suspects bad coating near the road. LPL plans to re-coat the lines 100 feet back on both sides of the road.

The pipe in question was recoated on August 10th.

C. MP 465.500 Griffith Station - Clean & re-coat pipe at the ground interfaces on the suction and discharge sides of each pump unit.

Pipe was blasted and recoated the week of June 25th.

D. MP 432.428 Parker Rd. - Rectifier C433 was not operative. LPL suspects that the rectifier was hit by lighting and will do additional testing and repair as needed.

The rectifier was repaired the day of the audit.

E. MP 383.090 (Line 6A) Dundee Station - Right-of-way needs clearing due north and south from the mainline valve located outside the station fencing.

Brushing has been completed.

F. MP 341.351 (Line 6A) Walworth Station - Clean & re-coat pipe at the ground interfaces on the pipe inside the pressure control valve building.

Pipe was blasted and recoated the week of June 25th.

G. MP 173.300 Marshfield Station - Rectifier C173A was not operative. LPL suspects that the rectifier was hit by lighting and will do additional testing and repair as needed.

The rectifier was repaired the week of June 25th.

H. MP 148.541 Owen Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3.

This work was completed during the week of June 18th.

I. MP 135.555 Lublin Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3.

This work was completed during the week of June 18th.

J. MP 99.250 Ladysmith Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3. There was a change in the labels that identify which pressures are being recorded in June, 1999. All charts stored prior to June, 1999 should be identified when the change occurred.

This work was completed during the week of June 18th

K. MP 63.348 (Line 6A) - Possible casing problem indicated by CP potentials. LPL plans additional testing and investigation

The potentials are high at this casing location due to the close proximity of the rectifier and ground bed. No further action is required.

L. MP 30.900 - The output for rectifier 031 has dropped from the last time the rectifier was checked. LPL suspects that the rectifier may have a bad anode. LPL will do additional testing and repair as needed.

Further investigation determined the rectifier had a faulty capacitor. The resulting repair brought the rectifier readings back to acceptable levels.

Archuletta, Phillip (OPSKC)

From: Doug.Klein@uspl.enbridge.com
Sent: Monday, August 27, 2001 7:05 AM
To: Phillip Archuletta
Cc: John.Sobojinski@uspl.enbridge.com; Jay.Johnson@uspl.enbridge.com
Subject: Re: Update

Please be advised that the following concern noted during your past audit within the Chicago Region at Lakehead Pipeline has been addressed:

> Forrester Rd Test Station had an actual read of .820 mV. Kimberly explained that a recoat project is underway this year and she is to forward DOT the reads after project is complete. Kimberly H 195.416(c)

On August 10, we successfully completed the Recoat Project on Mainline 6B at MP 500 Forrester Rd.

During the DOT Audit 6B Test Station on the upstream side of Forrester Rd., had a pipe-to-soil reading of -820 mv.
After the recoat project was completed/currently, the 6B Test Station has a pipe-to-soil potential of -996 mv on the upstream side & -1101 mv on the downstream side of Forrester Rd..

Note: We found disbonded coating on both 6B & 6B Loop on the upstream & downstream sides of Forrester Rd. Therefore, the Project included recoating 100' on both pipelines, on the both sides of the road. Also, I attached magnesium anodes through a shunt resister on each side of the road.

If there are any other outstanding deficiencies related to this audit, that the Corrosion Department need to address, please let me know ASAP. Thanks-

Take Care,
Kimberly Joy

TO: NORI 218.725.0405

ENBRIDGE Jim K Huber on 05/18/2001 01:53 PM

To: John W Hayos/IPL@IPL, Brad Shamla/IPL@IPL, David W Bryson/IPL@IPL, Mel Wyness/IPL@IPL, Allan D Baumgartner/IPL@IPL, Ian C Melligan/IPL@IPL
cc: Janet L Huggett/IPL@IPL
Subject: Proposed wording for Notification of Safety Concerns

As a line item noted by the DOT Audit, we may be deficient in addressing miscellaneous safety concerns called in by the public (this may include washed out pipe, unauthorized activity on the pipeline, etc.

The following is a draft procedure for the Database:

Notification of Safety Concern

When notified of a concern of a potential unsafe or hazardous condition:

1. Continue to operate the pipeline
2. Contact *the nearest station* on-call personnel immediately
3. Complete Incident Receiving Report Form

To address this concern, I propose we add the following warning to the Incident Information Form, p 3, Hazard Warning (to caller):

" We operate high pressure petroleum pipelines in your vicinity. It appears from your description and from observations of our control system, there is no immediate hazard from our pipelines. However, as a precautionary measure, we will dispatch company personnel to investigate the situation."

I also propose we add the following information to the Incident Information Form, p 4, Immediate Steps:

Company Personnel notified: ______________________ Time:__________
Company Personnel providing "All Clear": ______________________ Time:__________

Description of Follow Up Required (CCO Supervisor):____

Your feedback will be greatly appreciated. Please let me know what you think.

ENBRIDGE Jim K Huber on 05/18/2001 12:48 PM

To: Ian C Melligan/IPL@IPL, Janet L Huggett/IPL@IPL
cc:
Subject: Re: Notification of Safety Concern

195.401(b)
Q.20

Ian C Melligan

Next>> Previous TOC Backtrack

Notification of Safety Concern

When notified of a concern of a potential unsafe or hazardous condition: — popup

1. Continue to operate the pipeline
2. Contact *the* nearest station on-call personnel immediately
3. Complete Incident Receiving Report Form — hot link

Doug * *Note: Incident Report Receiving Form will be modified to include space for potential or unsafe conditions on the pipeline which will spawn follow up action by the Company.*

This form will be extensively revised to record:
- notification and/or all clear report (who, when)
- false alarm, safe condition & followup requirements
- response to caller

includes but is not limited to:
- unauthorized personnel on ROW or in facility
- exposed pipe
- station strobe light or horn sounding
- construction activity

Pipeline Integrity must recommend a prevention and maintenance program for internal corrosion by:

- determining treatment needs, concentrations and application methods
- selecting suitable chemical properties
- selecting appropriate in-line tools, if required
- selecting treatment locations

NOTE: Past performance and present day monitoring of inhibitor effectiveness continually affect these decisions.

195.401(b)

Q.31

Monitoring

Take beta foil readings at least 10 times per year with intervals not exceeding six weeks; however, make every effort to take readings once per month.

Further description of remedial action resulting from discovery of internal corrosion (i.e., beta foil readings) to be added here (DOT HQ Audit May 9/01). 195.401 (b)

NOTE: During cleaning and/or inhibitor injections, Pipeline Integrity may increase the frequency of beta foil readings.

NOTE: For more information on the company's beta foil and corrosion inhibitor plan, contact Pipeline Integrity.

Records

Excavation Inspection and/or Repair Report

Use the Excavation Inspection and/or Repair Report (CAN), or the Corrosion Inspection Report in the PLM Activity Report database (USA), to document both "as found" and "as left" conditions of exposed mainline or station piping during excavations.

USA

Distribute the Corrosion Inspection Report as follows:

1. Electronic original retained in Lotus Notes database.
2. Hard copy printed and filed at district/area office.
3. Hard copy printed and filed at Engineering.

USA

District office must retain Corrosion Inspection Reports for a minimum of two years.

195.402(d)(5)
Q.7

ENBRIDGE Jim K Huber on 05/18/2001 12:42 PM

To: Ian C Melligan/IPL@IPL, Janet L Huggett/IPL@IPL
cc:
Subject: Re: Abnormal Operation Procedure Review Process

Changes to the procedure as noted.

Ian C Melligan

Abnormal Operation Procedure Review ~~Process~~

~~At any time~~ After an initiated response of an Emergency Procedure *or abnormal operation* occurs:

1. *Within 24 hours* perform an initial procedure review to determine effectiveness of the procedure

   The initial procedure review shall include the following personnel:

   - Control Centre Coordinator on-shift during abnormal operation
   - Control Centre Operator on-shift during abnormal operation

2. If ~~review determines that~~ the procedure requires modification, notify ~~document and acquire approval from~~ Supervisor
3. Supervisor will initiate procedure change
4. Procedure will be modified and personnel shall be informed of change

Doug * *NOTE: CCO will add hot links which will activate this page to all procedures in this database descibing action during Emergency or abnormal operation .*

195.420(b)
Q.40

USA

Valve Inspection

Mainline valves, including remotely operated valves, must be inspected according to Maximo MP107 and MP256 at least twice during each calendar year at intervals not to exceed 7½ months.

In addition to the above, at least ~~once~~ twice each year the remote operation (i.e., open and close from control center) of remotely operated mainline valves must be verified according to Maximo MP179.

USA

Overpressure Safety Devices

Devices that limit, regulate and/or control maximum operating pressure must be inspected, tested or calibrated regularly according to Maximo:

- EP244 for pressure relief valves
- EP268 for pressure transmitters
- EP269 for pressure switches
- ET313 for OQT pressure allowable setpoints
- MP251 for pressure relief valves in crude service
- MP255 for pressure relief valves in NGL service
- MP290 for OQT pressure control valve system
- MP251 for OQT relief valve inspection and testing

Engineering, in cooperation with Operations employees, is responsible for determining if any device becomes inadequate in capacity and/or reliability for its intended purpose, and for ensuring the device is upgraded or replaced.

Records

CAN

Aerial Patrol Reports

Patrol pilots must document aerial inspections in the Aerial Patrol Report database. The report summarizes inspection dates and any abnormal conditions observed. Aerial Patrol Reports are permanently retained in the database and may be filed and at the regional office responsible for the area covered in the report.

NOTE: For Enbridge Pipelines (NW) Inc, the Aerial Patrol Report database is in the Lotus Notes NW Forum.

- D04-102, Painting, Coating and Lining
- D05-101, Berm, Containment
- D05-201, Foundation, Oil Storage Tank
- D05-401, Platforms, Stairs and Ladders
- D06-102, Piping Design, Station and Terminal
- D08-101, Oil Storage Tank
- D08-102, Oil Storage Tank, Roof
- D08-103, Oil Storage Tank, Accessories

Operating & Maintenance Procedures:
- Book 1: General Reference
- Book 2: Safety
- Book 4: Welding

Emergency Response Plan (ERP)
Waste Management Plan

Industry
American Petroleum Institute (API):
- API Guide for Inspection of Refinery Equipment, Chapter 13, Atmospheric and Low Pressure Storage Tanks
- API 650, Welded Steel Tanks for Oil Storage
- API 651, Cathodic Protection of Above Ground Storage Tanks
- API 652, Lining of Above Ground Petroleum Storage Tank Bottoms
- API 653, Section 4—Inspection
- **API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning and Stray Currents (DOT HQ Audit May 11/01) 195.432**
- API 2015, Safe Entry and Cleaning of Petroleum Storage Tanks
- API 2026, Safe Descent Onto Floating Roofs of Tanks in Petroleum Service
- API 2027, Ignition Hazards Involved in Abrasive Blasting of Atmospheric Storage Tanks in Hydrocarbon Service
- API 2207, Preparing Tank Bottoms for Hot Work

195.432
Q. 35

Canadian Council of Ministers of the Environment (CCME):
- Environmental Code of Practice for Aboveground Storage Tank Systems Containing Petroleum Products

BOOK 3: PIPELINE FACILITIES

ENBRIDGE

Section
STANDARDS

09-02-02
Subject Number

Subject
Tank Inspections

Purpose

Tank inspections confirm the structural integrity of the tank and its continued fitness for use.

Requirements

Inspection Frequency

Inspect in-service and out-of-service crude oil storage tanks on a schedule consistent with the recommended guidelines of API 653, Section 4--Inspection. Table 1 summarizes the types and frequencies of tank inspections. **Requirements for inspecting physical integrity of in-service aboveground breakout tanks (bullet tanks) according to API 2510, Section 6, to be added here (DOT HQ Audit May 11/01) 195.432**

195.432
Q.35

Qualifications

Employees assigned to do a Routine-In-Service Inspection must be familiar with tank farm operation, the tank and the characteristics of the product stored, e.g., terminal gauger, terminal supervisor, station chief, PLM supervisor or designate.

Inspection teams assembled to do a Formal In-Service or Formal Out-of-Service Inspections must be comprised of knowledgeable employees from regional/district offices, terminals/stations, and Pipeline Maintenance (PLM) or Engineering. One member of the inspection team must be certified as an Authorized API inspector as described in API 653.

Authorized API Inspectors

Authorized API inspectors must have education and experience equivalent to at least one of the following:

- degree in Engineering and one year of experience inspecting tanks, pressure vessels or piping
- two-year certificate in Engineering or Technology from a technical college, and two years of experience in operation, construction, repair or inspection, of which one year must be in the inspection of tanks, pressure vessels or piping
- equivalent of high school education and three years of experience in construction, repair, operation or inspection, of which one year must be in the inspection of tanks, pressure vessels or piping

- five years of experience in inspecting above-ground storage tanks in the petroleum or chemical industries

Table 1
Types and Frequencies of Tank Inspections

Type of Inspection	Maximum Interval	Done by
Routine In-Service	Monthly	local terminal operations employees
Routine In-Service	Annually	local terminal operations supervisor PLM supervisor or designate
Formal In-Service	5 years[1]	authorized API inspector[2]
Formal Out-Of-Service	20 years[1,3]	inspection team and authorized API inspector[2]

NOTES
1 More frequent inspections may be required due to corrosion.
2 May be a person who is not a company employee.
3 Frequency may be extended if a risk-based inspection (RBI) assessment is done according to API 653.

Evaluation—Repairs—Alterations

After routine inspections, evaluate documentation to determine:

- requirement for leveling tank
- extent of repairs required
- repair method
- requirement for hydrostatic testing

Refer major maintenance or operational issues to the station chief/terminal supervisor.

The inspection team must consult with Engineering on integrity issues that require repairs or alterations to a storage tank.

Records

Routine Inspections

Monthly

Check tank exteriors, including roofs, and document conditions in the terminal log. **Further clarification of conditions for conducting monthly routine inspections on tanks as well as corrective action when problems are found to be added here (DOT HQ Audit May 11/01) 195.432**

195.432 Q.35

Name of Operator:	Lakehead Pipe Line Company Inc.

HQ Address: Lakehead Pipe Line Company Inc. 1100 Louisiana, Suite 2950 Houston, TX. 77002	**System/Unit Name Address:** Crude System # 3
Co. Official (Pres or VP) Dan C. Tutcher; President **Telephone number:** 713-650-8900 **Fax number:** 713-650-3232 **Emergency Telephone:** 800-858-5253	**Telephone number:** **Fax number:** **Emergency Telephone:** 800-858-5253

Operator ID: 11169	**Unit ID:** 423 (System ID)	**Activity ID:** 93250, 91733, 91734, 91790, 91792

Unit IDs of adjacent Operator units:

Persons Interviewed	Titles	Phone Numbers
Refer to attached copies of		
attendance sheets.		

OPS Representative(s): David Barrett and Phil Archuletta

Company system maps - (copies for regional files, yes / no): Yes, placed in operator's file.

System/Unit Description:

System: Lines from the Canadian border near Marysville, MI. to Griffith, IN and then north to Superior, WI.
The system includes the following Central Region units:

Unit # 2953	Bay City
Unit # 12823	Griffith
Unit # 1343	Fort Atkinson
Unit # 1323	Superior

Portion of Unit Inspected:

Operator headquarters in Duluth, MN.
Pipeline facilities from the Canadian border near Marysville, MI. to Griffith, IN and then north to Superior, WI. Inspection included pump stations at Stockbridge, Carlisle, La Porte, Hartsdale, Griffith, Mokena, Lockport, Napierville, Dundee, Burlington, Crystal Lake, Walworth, Delavan, Cambridge, Waterloo, Rio, Portage, Adams, Cottonville, Vesper, Marshfield, Owen, Lublin, Sheldon, Ladysmith, Edgewater, Stone Lake, Minong, Hawthrone and Superior.

Was a Team O&M inspection completed previously? No	**If yes, document date?** / /

Note: If a Team O&M inspection was completed within the five (5) years, it is not necessary to review the entire O&M manual. However, modifications to the manual should be reviewed.

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description: LAKEHEAD HEADQUARTERS INSPECTION
Date: 5/8
Location: Duluth, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	Staff Engineer	U.S. DOT - OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Dave Barrett	Engineer	US DOT - OPS	816 329 3817	david.barrett@rspa.dot.gov
3	Brian Pierzina	Sr. Engineer	MN OPS	218-327-4218	brian.pierzina@state.mn.us
4	BOYD HAUGROSE	Eng. Spec.	MNOPS	218-847-7367	boyd.haugrose@state.mn.us
5	Doug A Klein	Safety & Compliance	Enbridge (U.S.)	218-725-0444	doug.klein@uspl.enbridge.com
6	Dave McNeill	Supervisor Integrity	Enbridge (US).	218-725-0595	dave.mcneill@uspl.enbridge.com
7	John Sobojinski	Operations Services Manager	Enbridge (US)	218-725-0505	John.Sobojinski@uspl.enbridge.com
8	Janet Hoggett	Sr. Technical Writer	Enbridge Pipelines	780-420-5142	Janet.Huggett@cnpl.enbridge.com
9	VINCE KOLBUCK	ENGINEER	ENBRIDGE U.S.	218-725-0563	vince.kolbuck@uspl.enbridge.com
10	Tom Lohman	Engineer	Enbridge US.	218 725-0568	tom.lohman@uspl.enbridge.com
11	Don Scott				
12	Tanis Elm	Sen Engineer	Enbridge US	218 725-0495	tanis.elm@uspl.enbridge.com
13	GAIL FOLLIS	ENG. SERVICES	ENBRIDGE US	218-725-0536	GAIL.FOLLIS@USPL.ENBRIDGE.COM
14	Nadine Lohman	Design & Serv. Clerk	Enbridge US	218-725-0537	Nadine.LOHMAN@USPL.Enbridge.com
15	ERIC A. WILLIAMS	SAFETY & COMPLIANCE	ENBRIDGE U.S.	219-922-3133	ERIC.WILLIAMS@USPL.ENBRIDGE.com

16	Dean Carpenter	Corp. Eng. Services	UNBRIDGE US 218-725-0525		dean.carpenter@uspl.ENBRIDGE.
17	Terri Breitzmann	Supervisor Eng. Design & Services	ENBRIDGE US 218-725-0511		TERRI.BREITZMANN.@USPL.ENBRIDGE.com
18	Kenneth Wergeland	Engineering	Enbridge US 218-725-0510		Ken.Wergeland@USPL.Enbridge.Co.
19	Karl Hodil	"	ENBRIDGE US 218-725-0507		karl.hodil@uspl.enbridge.com
20	JAY A JOHNSON	OPS. SERVICES	ENBRIDGE US 218/729-0512		jay.johnson@ "
21.	LYNNE HARRINGTON	TRAINING COORDINATOR	ENBRIDGE (US)	(218)725-0119	LYNNE.HARRINGTON@USPL.ENBRIDGE.COM
22.	Denise Hamsher	Mgr Business Services	"	218 725-0140	denise.hamsher@uspl.enbridge.com
23.	Jim Stien	Project Mgr.	"	(218) 725-0481	jim.stien@uspl.enbridge.com
24	Carl Mikkola	Sr. Integrity Eng.	"	218 725-0500	carl.mikkola@uspl.enbridge.com
25,	NANCY R. BRYCE	SR. SYSTEMS ANALYST	"	218-725-0150	nancy.bryce@uspl.enbridge.com

ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SAFETY
CENTRAL REGIONAL OFFICE
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description Records Review

Date 8-27-01 **Location** Duluth, MN

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	General Engineer	US DOT - OPS	816-329-3807	phillip.archuletta@rspa.dot.gov
2	Kimberly J. Harris	Sr. Corrosion Tech	LPL/ Enbridge Energy Partners	219-922-3133 x202	Kimberly.Harris@USPL.Enbridge.Com
3	John Sobojinski	Manager-Compliance + Risk Management	Enbridge (US)	218-725-0505	John.Sobojinski@USPL.Enbridge.com
4	DAVID MCNEILL	SUPERVISOR PIPELINE INTEGRITY	ENBRIDGE (US)	780-420-8731	
5	GARY HAUBRICH	TECH SUPERVISOR	LPL	218-759-6614	
6	RANDY WILBERG	SAFETY TRAINING COMPLIANCE	ENBRIDGE U.S.	715-394-1412	RANDY.WILBERG@USPL.ENBRIDGE.COM
7	Todd Gilseth	Safety Analyst	" "	218-759-6615	Todd.Gilseth@USPL.Enbridge.Com
8	Doug A Klein	Safety Team Leader	Enbridge U.S	715-394-1437	doug.klein@uspl.enbridge.com
9	JAY A JOHNSON	COMPLIANCE COORDINATOR	" "	218/725-0512	jay.johnson@uspl.enbridge.com
10	Dave Barrett	Engineer	OPS	816-329-3817	david.barrett@rspa.dot.gov
11	Brian Pierzina	Sr. Engineer	MNOPS	218-327-4218	brian.pierzina@state.mn.us
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ATTENDANCE SHEET

DOT-RSPA-OFFICE OF PIPELINE SA.
CENTRAL REGIONAL OFFIC.
901 LOCUST ST., ROOM 462
KANSAS CITY, MO 64106

Meeting Description GRIFFITH RECORDS REVIEW
Date 6-14 **Location** Griffith

	PERSON ATTENDING	TITLE	COMPANY	PHONE NUMBER	E-MAIL ADDRESS
1	Phil Archuletta	General Engineer	DOT - RSPA - OPS	816-329-3807	phillip.archuletta @rspa.dot.gov
2	ERIC A. WILLIAMS	SAFETY COORDINATOR	ENBRIDGE (U.S.)	219-922-3133	ERIC.WILLIAMS@USPL.ENBRIDGE.COM
3	Steve Booth	PLM SUPERVISOR	ENBRIDGE (U.S.)	219-922-3133	Steve.Booth@USPL.ENBRIDGE.COM
4	JAY A JOHNSON	OPS SERVICES COORD	ENBRIDGE US	218/725-0912 390-4911	jay.johnson@uspl.enbridge.com
5	JOHN GAUDERMAN	DISTRICT ENGINEER	ENBRIDGE (U.S.)	219-922-3133	john.gauderman@uspl.enbridge.com
6	MARK WILLOUGHBY	TECHNICAL SUPERVISOR	ENBRIDGE (U.S.)	219-922-3133	mark.willoughby@uspl.enbridge.com
7	GARRY O. THOMASON	TERMINAL SUPERVISOR	ENBRIDGE U.S.	219-922-3133	garry.thomason@uspl.enbridge.com
8	Dave Barrett	Engineer	DOT/OPS	816-329-3817	david.barrett @rspa.dot.gov
9	Jarrett Kachur	District Engineer	Enbridge (U.S.)	219-922-3133	jarrett.kachur@uspl.enbridge.com
10	KIMBERLY J. HARRIS	SR. CORROSION TECH.	ENBRIDGE (U.S.) PL	219-922-3133	KIMBERLY.HARRIS@USPL.ENBRIDGE.COM
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MOP/Overpressure Protection

Overpressure protection is essential to protect the pipeline from unexpected events. The operator should have procedures in place to ensure that the overpressure protective devices are adequate and in good working condition.

195.406(a)(1) Maximum Operating Pressure - Determining the MOP from design or test pressure or integrity calculations.

195.404(a)(3) Maps and Records - Each operator shall maintain current records of the maximum operating pressure of each pipeline system.

G-Q1) Does the operator have records to support the MOP applied to each line segment?

R1) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q1) Headquarters	X			
Q1) Field			X	
R1) Headquarters	X			
R1) Field			X	

1) Comments: The MOP of each pipeline segment was established by hydrostatic testing. The hydrostatic tests accounted for elevation differences and the characteristics of the products transported. System dynamic models are used to help determine pipeline parameters such as pressure setpoints. Different scenarios are run on the models to determine if any pressure changes are required. Pressure setpoints and allowances are determined by Lakehead's engineering department. Pump station base maximum discharge (BMD) pressures are set equal to are less than the established MOP for the entire line segment. For surge pressures, a first alarm warning is set at 5psig above BMD, a cascade shutdown of units at the station PLC is set at 25 psig above BMD, a cascade shutdown of units by the SCADA center is set at 35 psig above BMD and a complete shut-down of the entire pipeline is set at 65 psig above BMD or 110% BMD.

195.404(b)(1) Record of Discharge Pressure - Actual operating pressures representing three years of data.

G-Q2) Does the operator's pressure recording system retain sufficient details of pressure events, so as to exhibit pressure spikes that may have breached the MOP?

R2) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q2) Headquarters			X	
Q2) Field	X			
R2) Headquarters			X	
R2) Field	X			

2) **Comments:** Lakehead has begun a program to replace pen & ink pressure recorders with digital pressure recorders. Currently, 40 out of approximately 100 recorders have been replaced. These are six channel digital recorders which look at pressure every second, records the pressure every minute and records the highest and the lowest pressure within that one minute span, however, the exact time of each high/low is not kept. If an event causes a cascade shut-down, then the recorders capture all pressures between 5 minutes before and 5 minutes after the shut-down. The pressure data is stored on zip disks and one year's worth of data can be stored on one zip disk. The data is also sent and recorded at Lakehead's headquarters server as a backup.

195.428(a) Overpressure Safety Devices - Each operator shall at intervals not exceeding 15 months, but at least each calendar year, or in case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good working condition, and is adequate from the stand point of capacity and reliability of operation for the service in which it is used.

G-Q3) Have pressure safety devices been checked for pressure accuracy in one year intervals, or six month intervals for highly volatile liquids?

R3) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q3) Headquarters			X	
Q3) Field		X		
R3) Headquarters			X	
R3) Field	X			

3) **Comments:** Pressure safety device inspections are recorded in Maximo. Station safety devices (pressure switches and transmitters) are checked semi-annually. Pressure relief valves are checked annually. Verified by records review at Bay City, Griffith, Fort Atkinson and Superior.

Field: Chicago District - (1) MP 148.541 Owen Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3. (2) MP 135.555 Lublin Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3. (3) MP 99.250 Ladysmith Station - The pressure recording charts need a legend or verbal description on the charts that specifically identifies which pressures are being recorded in Channels 1, 2 and 3. There was a change in the labels that identify which pressures are being recorded in June, 1999. All charts stored prior to June, 1999 should be identified when the change occurred.

195.128 Station Piping - Must meet applicable requirements if subjected to system line pressure.

G-Q4) Have the appropriate pressure controlling devices been installed to protect the lower-pressure piping in the manifold and/or at pump stations?

R4) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q4) Headquarters	X			
Q4) Field	X			
R4) Headquarters			X	
R4) Field			X	

4) Comments: Pressure controlling device procedures / criteria are contained in Lakehead's Engineering Standard D12-104. Lakehead uses a tiered approach to pressure control alarming/shut-down. The tiers are 1) alarm, 2)shut-down and 3)high-high shut-down (a station shut-in will also occur). Redundant transmitters are used to send data back to the PLC. The PLC uses the lowest transmitter pressure reading for control. Setpoints at station PLC's are established based upon what product is being transported. Some of Lakehead's stations also use variable frequency drive pumps to control discharge pressures. Surge relief for NGL's is provided by bullet tanks located at Lakehead's Superior Terminal/Station.

195.402(d)(1) Abnormal Operation - Responding to, investigating and correcting the cause of unintended closure of valves or shutdowns; and an increase or decrease in pressure or flow rate outside normal operating limits.

195.404(b)(2) Maps and Records - Each operator shall maintain for at least 3 years daily operating records of any emergency or abnormal operation.

G-Q5) Did the safety devices function properly during abnormal operation?

R5) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q5) Headquarters	X			
Q5) Field	X			
R5) Headquarters			X	
R5) Field	X			

5) **Comments:** High pressure shut-down is provided at delivery points. Lakehead has a policy that if a high pressure or other abnormal event cannot be resolved in 10 minutes, then a shut-down is initiated. Verified by records review at Bay City, Griffith, Fort Atkinson and Superior.

195.402 (d)(2) Procedures for checking variations after abnormal operations - Checking for safe operation at sufficient critical locations to determine continued integrity and safe operation.

195.404(b)(2) Maps and Records - Each operator shall maintain for at least 3 years daily operating records of any emergency or abnormal operation.

G-Q6) Are procedures and forms used to document the occurrence of unscheduled shutdowns and over-pressure situations?

R6) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q6) Headquarters	X			
Q6) Field			X	
R6) Headquarters	X			
R6) Field			X	

6) **Comments:** Abnormal events are recorded on Pipeline Incident forms in the field. Lakehead's control center uses a "Facilities Management" (FACMAN) report for reporting such events as station unit problems, lockouts, overpressures and any significant activity that is considered outside of ordinary operations. Events generate internal memos and messages to field operations on causes, corrective actions and preventive procedures. Events involving surge relief valves are FACMAN not recorded. All FACMAN records are kept at Lakehead's Edmonton, Alberta, Canada office.

195.402(d)(5) Procedural manual for operations, maintenance, and emergencies - Abnormal Operation - Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

G-Q7) Does the procedure direct the analysis of abnormal conditions to prevent future abnormal events?

R7) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q7) Headquarters		X		
Q7) Field			X	
R7) Headquarters			X	
R7) Field			X	

7) Comments: Lakehead did not have a formal written procedure for analyzing abnormal events. Lakehead looks at what happened and why, but there was no direction as to how analysis is done on a company wide basis. Lakehead has a "PIPELINE CONTROL COMMITTEE" that meets quarterly to review philosophies, give direction/coordination and establish priorties for the control/operation of Lakehead's pipelines. The goal of the committee is to achieve a safe, efficient, environmentally sound operation compliant with regulations.

195.302(c) - Compliance deadlines for pipelines that have not been pressure tested.

G-Q8) Has the operator developed a plan for testing its pipeline systems?

R8) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q8) Headquarters			X	
Q8) Field			X	
R8) Headquarters			X	
R8) Field			X	

8) Comments: All of Lakehead's pipelines have already been tested.

195.426 Scraper and Sphere Facilities - Pressure indication and relief devices.

G-Q9) Do traps have functioning visual or audible indications of pressure to alert operating and maintenance personnel about elevated trap pressure?

R9) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q9) Headquarters			X	
Q9) Field	X			
R9) Headquarters			X	
R9) Field			X	

9) Comments: Lakehead's procedures on traps are in Lakehead's O & M Book 3, Section 08-03-01and 08-03-02. Field inspections verified that traps are provided with devices to alert personnel about high pressure in the trap.

195.262(a) Pump Station Ventilation and Warning Devices - Detecting hazardous vapors.

G-Q10) Has the operator installed warning devices in pump station buildings to warn of the presence of hazardous vapors?

R10) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q10) Headquarters	X			
Q10) Field	X			
R10) Headquarters			X	
R10) Field			X	

10) Comments: Procedures for detecting the presence of hazardous vapors are in Lakehead's Engineering Standard D12-202. At Lakehead's pump stations, there are vapor detectors located either near the units or along the interior building walls. Visual alarm on the local PLC panel. The control center also receives an alarm. The devices give a warning at 20% LEL and a alarm and shut-down at 40 % LEL. Thermal (heat) switches are provided above each pump unit for fire detection and are set at 125° F.

195.402(c)(9) Facilities not equipped to fail safe - As described in 195.402(c)(4), facilities that are located in areas that control the receipt and delivery of hazardous liquids would require an immediate response by the operator to prevent hazards to the public must be monitored... usually by SCADA if unattended.

G-Q11) Are all the unattended locations on the operator's system which control the receipt and delivery of hazardous liquids monitored?

R11) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q11) Headquarters	X			
Q11) Field	X			
R11) Headquarters			X	
R11) Field			X	

11) Comments: All remote locations are monitored by Lakehead's control center in Edmonton, Alberta, Canada. Equipment is designed to fail-safe. Lakehead has backup communication systems if the primary systems fail. A loss of communications causes local PLC's to go to limits which significantly reduces line through put rate. If communications at a remote site are lost for more than 10 minutes, then the control center will start a systematic shut-down procedure.

195.408(a) Communications System for Pipeline Information - Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline.

G-Q12) Will system operation be affected by communication outages or SCADA failure?

R12) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q12) Headquarters	X			
Q12) Field			X	
R12) Headquarters			X	
R12) Field			X	

12) Comments: Lakehead has a back-up control center located in Superior, WI. The back-up center has 5 to 6 consoles and in the event that a console fails, any one of the other consoles can be used. If for any reason, the building housing the control center at Edmonton had to be evacuated, then the control center would shut-down all pipelines and personnel would temporarily relocate to a another back-up control center at a Edmonton terminal that is approximately 15 to 20 minutes from the main control center. Control personnel would then begin a systematic re-start of all pipelines. Back-up control centers are tested a minimum of two times per year.

G-Q13) Best Practice:
Does the operator have a means to prevent controller fatigue?

13) Comments: The Lakehead control center at Edmonton, Alberta, Canada has ergonmically designed console controls, chairs and room lighting. There are two 12 hour shifts, 7:00AM - 7:00PM and 7:00PM - 7:00AM. The controllers work 2 days, 3 nights and then have 5 days off. They then work 3 days, 2 nights and have 5 days off. Controllers are provided with a tread mill for excersice and a mini-kitchen. Controllers are cross-trained there is rotation among the consoles. Normal operation is to have one operator per console per shift. There is one control center coordinator per shift to supervise the controllers.

195.134 Definition and application of the computational pipeline monitoring (CPM) leak detection system.

G-Q14) Does the operator have a leak detection system?

R14) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q14) Headquarters	X			
Q14) Field			X	
R14) Headquarters			X	
R14) Field			X	

14) Comments: Leak detection systems are provided for Lines 1, 2, 3, 5 and 13. A leak detection system for Line 4 is almost ready, the system is installed but the alarms are not active because they are fine tuning the settings. A leak detection system for Line 6 has been budgeted. Leak detection is not provided for Lines 14 and 17(probably will be done next year). The system used is a Stoner Leak Detection System which uses real time transient hydraulic modeling of the pipelines. The system compares the model with what is actually occurring on the pipelines. The sensitivity ranges vary for each line, but an example would be Line 3 where the sensitivity is 28% of total flow over 5 minutes, 11% over 20 minutes and 6% over 2 hours. The leak detection system is part of the "10 minute" rule, which means that if the reason for a leak detection indication cannot be resolved within 10 minutes, then the line will be shut-down.

195.404(c)(3) Maps and Records - Each operator shall maintain a records for two years.

G-Q15) Does the operator maintain records per the requirements of 195.404(c)(3)?

R15) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q15) Headquarters	X			
Q15) Field	X			
R15) Headquarters	X			
R15) Field	X			

15) Comments: Procedures for record keeping requirements are found in Book 1, Sections 05-01-01 and 05-02-01 of Lakehead's O & M manual. Records such as PLM Reports, Permanent Repair Reports and Corrosion Inspection Reports are in Lakehead's PLM databases.

Field: Bay City, Chicago and Superior Districts - Records reviewed were in compliance.

Engineering Drawing Review

195.402(c)(1) Maintenance and Normal Operation - Making construction records, maps, and operating history available for safe operation and maintenance.

G-Q16) How does the operator control engineering drawing revision, review, approval, and distribution?

R16) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q16) Headquarters	X			
Q16) Field	X			
R16) Headquarters	X			
R16) Field	X			

16) Comments: Lakehead's drafting department has responsibility for drawing development and distribution. The process for handling drawings are located in Lakehead's Engineering Procedures. Project Engineers have responsibility for making sure that as-builts are accurate (with regard to what was installed) and completed at the end of each construction project. Drafters go to the field to verify dimensional accuracy. It takes approximately 1 to 2 months to have changes placed on the alignment sheets and new alignment sheets are issued toward the end of the year, usually December or January. Field personnel use mark-ups in the interim. Flow diagrams are the first drawings to be updated and any changes that would effect the control center are submitted to the control center for incorporation into control center screens and operations.

195.404(a) Each operator shall maintain current maps and records of its pipeline systems.

Q17) Do the operator's "as-built" agree with field? Do the SCADA terminals get updates?

R17) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q17) Headquarters	X			
Q17) Field	X			
R17) Headquarters			X	
R17) Field	X			

17) Comments: Refer to comments under Q16.

Field: Bay City, Chicago and Superior Districts - Field drawings were reviewed against actual field facilities and were OK.

195.402(c)(1) Maintenance and Normal Operation - Making construction records, maps, and operating history available for safe operation and maintenance.

Q18) How are completed construction activities, such as facility modifications, communicated to the controller?

R18) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q18) Headquarters	X			
Q18) Field			X	
R18) Headquarters	X			
R18) Field			X	

18) Comments: Lakehead has a PLC coordinator and on any new projects, the coordinator works with the project engineer to see what is needed if PLC programming changes are required. Programs are stored at the headquarters level server along with hard copies. Field technicians have hard copies and storage disks. All PLC programs are protected with a "read only" feature. Refer to comments for Q16 for additional information.

Process Control and Flow Schematic Drawing Review

Differences between process control engineering drawings and pipeline facilities have resulted in incidents and abnormal operating conditions. We have found that physical changes made to facilities are sometimes not reflected in engineering drawing or SCADA displays. The company should have a procedure in place that ensures changes in the field are communicated to appropriate personnel and correspondence (i.e. maps, records and drawings) are corrected.

195.404(a) Each operator shall maintain current maps and records of its pipeline systems.

G-Q19) Do engineering, process control, and flow schematic drawings adequately depict current facilities and operations?

R19) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q19) Headquarters	X			
Q19) Field	X			
R19) Headquarters	X			
R19) Field	X			

19) Comments: Field: Bay City, Chicago and Superior Districts - Field drawings were reviewed against actual field facilities and were OK.

Review of First Discovery Reports

First discovery reports are reports that may identify potential problems on, or in the vicinity of the pipeline, that could affect pipeline integrity and/or public safety. These reports could include any pipeline safety inspection and/or survey reports, landowner or general public reported concerns, patrol reports. Listed below are a few high impact examples.

195.416(e) External Corrosion Control - the operator shall examine exposed pipe for external corrosion.

195.416(i) External Corrosion Control - the operator shall clean, coat for the prevention of atmospheric corrosion

195.401(b) Operation and Maintenance - the operator shall correct any condition that could adversely affect the safe operation of its pipeline within a reasonable time.

G-Q20) Does the operator disseminate, monitor, and follow-up the information obtained from first discovery reports?

R20) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q20) Headquarters		X		
Q20) Field		X		
R20) Headquarters			X	
R20) Field	X			

20) Comments: Lakehead's procedures require modification to include first discovery reports from the public, employees, contractors and sources other than those that are reported directly to the control center.

Field: Bay City, Chicago and Superior Districts - Discovery reports and follow up records were reviewed and were OK.

195.416(e) cont'd

G-Q21) Does the company follow-up and document discovered exposed spanning pipe in water and do they take fluctuating water levels into consideration?

R21) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q21) Headquarters	X			
Q21) Field			X	
R21) Headquarters			X	

R21) Field			X	

21) Comments: Whenever field personnel discover exposed spanning pipe that may require evaluation, then Engineering is notified. Engineering does an analysis (including evaluation of stresses) and prepares a plan of action for corrective measures needed. Exposed pipe is handled on a case-by-case basis and a formal list of all exposed pipe locations is not kept. A table of maximum allowable length between pipe supports is located in Book 3 of Lakehead's O & M manual. The table shows that the range of unsupported pipe lengths is 80 to 115 feet depending on pipe diameter and wall thickness.

195.408(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system, and (b) The communication system required by paragraph (a) of this section must, as a minimum, include means for: (1) Monitoring operational data as required by §195.402(c)(9);(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and (4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.

G-Q22) How does the operator follow-up and document public/landowner complaints concerning safety and integrity issues?

R22) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q22) Headquarters	X			
Q22) Field	X			
R22) Headquarters	X			
R22) Field	X			

22) Comments: Most complaints would go to Lakehead's 800 emergency number at the control center. These calls would be recorded on an incident information form. An initial assessment would be done to determine if an immediate shut-down is required. If there is a shut-down, it is recorded in LPL's "Facilities Management" (FACMAN) program. The first call would be to the police, if necessary. The second call would be to field personnel to respond to and investigate the called in report.

195.401(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under §195.402(a) of this subpart; and (b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it

presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

195.404(b) Each operator shall maintain for at least 3 years daily operating records that indicate-

(1) The discharge pressure at each pump station; and
(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

(c) Each operator shall maintain the following records for the periods specified;

(1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.
(2) The date, location, and description of each repair made to parts of the pipeline other than pipe shall be maintained for at least 1 year.
(3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

G-Q23) How does the operator follow-up and document integrity issues system-wide?

23) Comments: Lakehead has a "Pipeline Integrity" (PI) group which is responsible for the overall integrity management program. When internal inspection tool runs are made, results go to the PI group which does an analysis for data validity and defects that are of a critical nature. Priority is first given to anomalies considered to be of a critical nature. The PI group also prepares any dig list. The PI group communicates with field personnel and vendors on what is actually found versus what the tool run data reported. Historically, LPL has not used integration of CP and pig run data to analyze potential problem areas. However, LPL is in the initial stages of using an integration of data program. A close interval survey is done every 5 years an a rotating basis among the district areas.

Training

Operator errors result in pipeline incidents every year. We are trying to determine what processes operators have in place to address the training requirements and safety needs of the pipeline industry.

195.403 Training

G-Q24) Has the operator established and conducted a continuing training program to instruct operating and maintenance personnel?

R24) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q24) Headquarters	X			
Q24) Field	X			
R24) Headquarters	X			
R24) Field	X			

24) Comments: Initial training is per Performance Based Training (PBT). PBT has 3 levels of training for each position as follows - 1) performed the task; 2) assisted in performing the task and 3) received an explanation/demonstration of the task. PBT requires that the employee's supervisor sign off when a job/task is completed. LPL maintains a database for recording tasks, dates of performance and sign off dates.

195.403 Cont'd

Q25) Does the operator review, at intervals not exceeding 15 months, but at least once each calendar year, the performance of their personnel in meeting the objectives of the training program?

R25) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q25) Headquarters	X			
Q25) Field	X			
R25) Headquarters	X			
R25) Field	X			

25) Comments: LPL's training procedures include an annual performance review of personnel. A review is also done on the training topics to see how topics can be improved to meet training objectives.

195.509(a) Operators must have a written qualification program by April 27, 2001.

G-Q26) Has the operator developed a written qualification program?

R26) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q26) Headquarters	X			
Q26) Field			X	
R26) Headquarters	X			
R26) Field			X	

26) Comments: LPL's operator qualification program has been in development over the past 2 years. LPL now has a formal written OQ plan with an effective date of 4/27/01. The elements of the plan meet the criteria of the OQ regulation.

Corrosion Control

Corrosion is a major cause of accidents and disbonded coating is often the leading factor. A check of close interval surveys for depressed areas may reveal disbonded coating. Pipe segments adjacent to locations where corrosion is found could easily develop corrosion because it may be subject to the same conditions. Additional preventive measures should be taken in these areas such as bell hole examinations and smart pigging activities. Review locations where clock-spring repairs were made to identify pipe segments that are subject to active corrosion.

195.414 Cathodic Protection

195.416 External Corrosion Control

195.418 Internal Corrosion Control

G-Q27) Does the company maintain a comprehensive corrosion control program?

R27) Associated Records (annual survey, rectifiers)?

	Satisfactory	Needs Improvement	N/A	N/C
Q27) Headquarters	X			
Q27) Field		X		
R27) Headquarters			X	
R27) Field	X			

27) Comments: LPL maintains a comprehensive corrosion control program which covers both internal and external corrosion. There is one senior corrosion technician located at LPL's Chicago District office. This senior corrosion technician assists with corrosion issues on a company wide basis. Corrosion issues at the District level are handled by a corrosion technician based out of each District office. The actual surveys are done by a third party contractor and the District corrosion technician reviews the contractor's work to ensure compliance with company criteria and regulations. Program includes close interval surveys, CP interference tests with other companies, "on-off" surveys and recently includes sharing of information between the pipeline integrity group and the corrosion control group.

Field: Chicago District - (1) MP 500.137 Forrester Rd. - Low CP potentials: Line 6B: -0.820 Line 6B Loop: -0.836 Note: LPL suspects bad coating near the road. LPL plans to re-coat the lines 100 feet back on both sides of the road. (2) MP 465.500 Griffith Station - Clean & re-coat pipe at the ground interfaces on the suction and discharge sides of each pump unit. (3) MP 432.428 Parker Rd. - Rectifier C433 was not operative. LPL suspects that the rectifier was hit by lighting and will do additional testing and repair as needed. (4) MP 341.351 (Line 6A) Walworth Station - Clean & re-coat pipe at the ground interfaces on the pipe inside the pressure control valve building. (5) MP 173.300 Marshfield Station - Rectifier C173A was not operative. LPL suspects that the rectifier was hit by lighting and will do additional testing and repair as needed.

Field: Superior District - (1) MP 30.900 - The output for rectifier 031 has dropped from the last time the rectifier was checked. LPL suspects that the rectifier may have a bad anode. LPL will do additional testing and repair as needed. (2) MP 63.348 (Line 6A) - Possible casing problem indicated by CP potentials. LPL plans additional testing and investigation.

G-Q28) Best Practice: Industrial Standards - RP0169, NACE
Is the company's corrosion program under the direction of a qualified person? (List the qualifications in the comment field.)

28) Comments: Each district is responsible for and manages the corrosion control program within the district. The company has a Senior Corrosion person based at of Griffith, Kimberly Harris, who is available to assist with problems and questions on a system wide basis. Ms. Harris is a Certified Corrosion Technologist.

195.402 Procedural Manual for Operation, Maintenance, and Emergencies - the operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

G-Q29) Are corrosion control procedures in place and do they follow Part 195/NACE/industry standards?

R29) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q29) Headquarters	X			
Q29) Field	X			
R29) Headquarters			X	
R29) Field			X	

29) Comments: LPL's corrosion control program follows Part 195 and NACE standards. Corrosion control procedures are found in Book 3 of Lakehead's O & M manual. Refer to the comments for Q27 for additional information.

195.402 cont'd

195.414 cont'd

195.416 cont'd

195.418 cont'd

G-Q30) How is the gathered information reviewed and analyzed to identify problem areas?

R30) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q30) Headquarters	X			

Q30) Field	X			
R30) Headquarters	X			
R30) Field			X	

30) Comments: In the past, LPL has not integrated CP data with pipeline internal inspection data to identify problem areas, but this has recently changed as LPL's integrity management group seeks to improve the integrity program. Company experts meet to determine what the integrity program/plan should be. Many factors are considered in the plan and an Enbridge wide plan is developed. The integrity plans are developed as a system, but each line is individually evaluated.

195.401(b) Operation and Maintenance - the operator shall correct any condition that could adversely affect the safe operation of its pipeline within a reasonable time.

G-Q31) Under what conditions does the operator take prompt remedial action?

R31) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q31) Headquarters		X		
Q31) Field			X	
R31) Headquarters			X	
R31) Field			X	

31) Comments: Priority for prompt remedial action is given to problems that may indicate an imminent failure, would result in a immediate impact on the pipeline MOP or flow rate, would impact on public safety or would impact environmentally sensitive areas. Beta foils are used to determine internal corrosion problems, but LPL needs formal written procedures detailing how beta foils are used, criteria required and what the corrective process is when the beta foils due indicate a problem. The beta foil data is analyzed by a third party contractor. The pipeline integrity group uses internal inspection data to determine problem areas and corrective actions required. LPL has field protocol of what is done for prompt remedial action on finding any condition that could adversely affect the safe operation of LPL's pipeline systems, especially with regard to corrosion control procedures and remedial actions taken. However, LPL has not formalized the process by inclusion of specific verbiage in LPL's O & M manual.

Q32) Best Practice:
What factors are considered in determining the need for and timing of pigging and close interval surveys?

32) Comments: Lakehead uses such factors as coating type, product type, leak history, pipe type, operation history, internal inspection history, defect history and seam weld type. Lakehead will begin using an overlay of high resolution tool runs to determine corrosion rates to determine future intervals for tool runs. Close interval surveys are done every 5 years.

Tanks

Inspection criteria relating to Tankage.

195.2 Definition - Breakout Tank means a tank used to (a) relieve surges in *hazardous liquid pipeline system* or (b) receive and store hazardous liquid transported by a pipeline for re-injection and continued transportation by pipeline.

G-Q33) Has the operator correctly identified/classified its tanks?

R33) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q33) Headquarters	X			
Q33) Field	X			
R33) Headquarters			X	
R33) Field			X	

33) Comments: Tanks identified as breakout tanks and OPS jurisdictional at Superior, Clearbrook, Stockbridge and Griffith. The NGL bullet tanks at Superior are used strictly for surge pressure relief. Tanks are considered to be dual jurisdictional between OPS and the ICC at the Hartsdale Terminal. The Hartsdale tanks are storage tanks that can be used for "lease".

195.428(b) Over pressure safety devices - In case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

G-Q34) Does the operator ensure relief valves are tested?

R34) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q34) Headquarters	X			
Q34) Field	X			
R34) Headquarters			X	
R34) Field	X			

34) Comments: There are relief valves on the NGL bullet storage tanks at Superior. These relief valves are tested every 5 years.

195.432 Breakout tanks - Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each breakout tank (including atmospheric and pressure tanks).

G-Q35) Has the operator conducted the appropriate inspections? Does the operator use available industry codes and standards to uniformly establish maintenance and repair inspection criteria for the breakout tanks?

R35) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q35) Headquarters		X		
Q35) Field		X		
R35) Headquarters			X	
R35) Field	X			

35) Comments: Procedures for tank inspections are located in Book 3, Section 09-02-02 of Lakehead's O & M manual. LPL's procedures need revision to include verbiage on what the corrective action process is if problems are found during any breakout tank inspection. LPL should implement a method to address conclusions and recommendations made during a tank inspection, and the status of corrective actions. The procedures also need specific references to industry standards API 2003 and API 2510. The procedures need specific verbiage on what items to look for during tank inspections. LPL uses API653 inspection criteria. The tank floors are given a 100% MFL scan. The inside seam on the bottom of the tank is given a 100% vacuum box test. LPL does not have a centralized tank inspection program run from headquarters. The headquarters tank personnel act in an advisory role to the Districts. The Districts maintain the inspection records, request funds for inspections and decide on threshold intervals for tank inspections.

G-36) Best Practice:
Are the breakout tanks equipped with high level alarms?

36) Comments: Lakehead's breakout tanks have two stages of high level alarms set at "High" and at "High - High". The "High - High" alarm is independent of the "High" alarm. The "High" level is via a tape type floating gauging system. The tape gauging system also includes a gauge near the bottom of each tank which can be used for a visual indication of the tank's level.

Valves

It is important that isolation valves be in good working order and accessible when needed.

195.116 Valves

G-Q37) Has each valve been properly designed, marked, and tested?

R37) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q37) Headquarters	X			
Q37) Field	X			
R37) Headquarters			X	
R37) Field			X	

37) Comments: Specifications for Lakehead's valves are located in Lakehead's Engineering Standard D06-105. Engineering sets the specifications for all valves. Lakehead orders valves meeting API6D criteria. The valves are full open port, rising stem valves. All mainline valves are ordered with a open/close indicator.

195.260 Valve Locations - A valve must be installed at each of the following locations: on the suction and discharge end of a pump station; on each line entering or leaving a breakout tank area; along the pipeline that will minimize damage or pollution from accidental discharge; on each lateral takeoff from the trunk line; on each side of a water crossing that is more than 100 feet wide at high-water mark; and on each side of a reservoir holding water for human consumption.

G-Q38) Are mainline valves properly identified and located?

R38) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q38) Headquarters	X			
Q38) Field	X			
R38) Headquarters			X	
R38) Field			X	

38) **Comments:** Lakehead considers any valve that blocks, controls or isolates mainline flow is a mainline valve. A risk management type process is used to identify where valves should be located. Priority consideration is given to high risk areas such as wetlands. Mainline valve lists are maintained in each district.

195.420(a) Valve Maintenance - the operator shall maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times.

G-Q39) Does the operator maintain each valve that sees mainline pressure and flow in good working order?

R39) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q39) Headquarters	X			
Q39) Field	X			
R39) Headquarters			X	
R39) Field			X	

39) **Comments:** Valve maintenance procedures are located in Book 3, Section 03-02-01 of Lakehead's O & M manual.

Field: Bay City District - Field inspection included a random check and partial operation of valves to observe if the valves were in good working order. This district's valves were OK with one exception, the open/close indicator rod on one valve was inoperable. The valve operated OK but the rod had somehow become detached from the valve stem.

Field: Chicago & Superior Districts - Field inspection included a random check and partial operation of valves to observe if the valves were in good working order. The valves in these districts were OK.

195.420(b) Valve Maintenance - the operator shall, at intervals not exceeding 7 ½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

G-Q40) Does the operator inspect each mainline valve on a bi-annual 7 ½ month basis to determine that their valves are functioning properly?

R40) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q40) Headquarters		X		
Q40) Field	X			
R40) Headquarters			X	
R40) Field	X			

40) Comments: LPL's procedures on valve inspections are confusing in that the procedures could be interpreted to mean that valve inspections are only done once per calendar year, when in fact, LPL inspects valves twice per calendar year per code requirements. The procedures need clarification so that there is no doubt that valves are to be inspected twice per calendar year. LPL did have one valve inspection interval that was exceeded due to flooding and it was suggested to LPL that comments regarding unusual conditions affecting inspections should be added to the valve inspection record.

Field: Bay City, Chicago and Superior Districts - Field check of records verified that valve inspections are done twice per calendar year.

195.420(c) Valve Maintenance - the operator shall provide protection for each valve from unauthorized operation and from vandalism.

G-Q41) Does the operator protect their valves from vandalism?

R41) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q41) Headquarters	X			
Q41) Field	X			
R41) Headquarters			X	
R41) Field			X	

41) Comments: Mainline valves are secured with a chain and padlock to prevent unauthorized operation. Steel pipe guard posts are installed around each valve that has the potential to be damaged from mowing activities, farming operations, land maintenance activities, street/highway/road maintenance activities and/or vehicular traffic.

Field: Bay City, Chicago and Superior Districts - Field inspection of random valve locations verified that valves are properly protected from vandalism.

195.404(c)(3) Maps and Records - Each operator shall maintain a record of their inspection of mainline valves for two years.

G-Q42) Does the operator maintain proper records for mainline valves?

R42) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q42) Headquarters			X	
Q42) Field	X			
R42) Headquarters			X	
R42) Field	X			

42) Comments: Records for mainline valves are kept in each District office.

Field: Bay City, Chicago and Superior Districts - Mainline valve records for this District were OK.

G-Q43) Best Practice:
Are valves located to provide quick response for environmentally sensitive areas such as drinking water sources, national parks, etc.?

43) Comments: For valve locations, priority is given to such areas as wetlands, high populated areas and major river crossings. When locations for valves are considered, Lakehead looks at such parameters as access for vehicles, availability of electric power and security measures required. In the event of a leak detection, all valves between the two adjacent stations would be closed. Lakehead's remotely operated valves have an average closure time of approximately 3 to 6 minutes. Lakehead does not have a overall conscious effort to identify environmentally sensitive areas to install valves, but Lakehead does have topographic maps with color coded sensitivity ratings which are used for response activity and emergency planning.

G-Q44) Best Practice:
Are there any locations where special features, such as valve stem extension in flood plains, had to be incorporated because of difficulty in complying with the above? Are there any automatic or remotely controlled valves?

44) Comments: Lakehead has used valve extensions on valves where appropriate. Some of Lakehead's more "critical" mainline valves, such as "sectionalizing" valves, are remotely controlled. In the event of a power failure, the remotely controlled valves stay open. Typically, Lakehead does not monitor the pressure at the remotely controlled valves. Some other strategic valves, such as stream/river crossings are a mixture of remotely operated and manually operated.

Patrol Program

An effective patrol program will combine information throughout the company to prevent damage to the pipeline and detect damage that has already occurred. Companies are encouraged to correlate information from a variety of sources such as comparing patrolling records with internal inspection data. Communication and areas of responsibility between patrol pilots and the personnel who follow-up and track the reports should be clearly defined so that both parties understand their role in preventing outside force damage.

195.402 Procedure Manual for Operations, Maintenance and Emergencies.

G-Q45) Does the operator have an adequate patrolling program ?

R45) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q45) Headquarters	X			
Q45) Field		X		
R45) Headquarters	X			
R45) Field	X			

45) Comments: Lakehead does aerial patrols every other week. Procedures for patrolling are located in Book 3, Section 03-02-01 of Lakehead's O & M manual. Aerial discoveries are reported on a "Daily Patrol Report" and are completed in electronic format. Field personnel respond to the reports and enter confirmation of actions taken electronically on company's computer. Lakehead uses it's own pilot for aerial patrol and helicopters are the main aircraft type used. If the helicopters are in for service, then Lakehead uses a third party aerial service out of Bemidji, MN. In the event of special conditions, such as flooding or sections that may be under a pressure restriction, the patrol frequency is increased. When a new pilot is hired, the new pilot will fly with the previous pilot for at least 2 weeks.

Field: Chicago District - MP 515.100 (Line 6B) - Right-of-way needs clearing on the east side. MP 383.09 (Line 6A) Dundee Station - Right-of-way needs clearing due north and south from the mainline valve located outside the station fencing.

Line Markers and Damage Prevention (Locating and Marking Pipelines)

It is critical that personnel who locate buried pipe in the course of their work are qualified and competent. Personnel performing this work may be operator or contract service company employees (line locate company, corrosion survey company, pipeline surveyors, etc.).

195.410(a) Line Markers - each operator shall place and maintain line markers over each buried pipeline.

G-Q46) Are markers located at public road crossing, railroad crossings, and in sufficient number along the remainder of each buried line?

R46) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q46) Headquarters	X			
Q46) Field	X			
R46) Headquarters			X	
R46) Field			X	

46) Comments: Lakehead's policy is to place markers at road / railroad crossings, water crossings and other significant areas accessible to the public. At valve locations, LPL uses signs or markers or a combination of both.

Field: Bay City, Chicago and Superior Districts - Field check of random locations verified correct usage of signs and markers.

195.402(c)(13) Procedural manual for operations, maintenance, and emergencies - Maintenance and normal operations - the manual must include procedures for periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

195.442(a) Damage prevention program - if the operator does not participate in a public service program, such as a one-call system, then the operator of a buried pipeline must carry out a written program to prevent damage to that pipeline from excavation activities.

G-Q47) Does the operator participate in a public service program? If not, does the operator evaluate their damage prevention procedures and take corrective action where deficiencies are found?

R47) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q47) Headquarters	X			
Q47) Field	X			
R47) Headquarters			X	

R47) Field	X			

47) Comments: The public service programs that Lakehead participates in are 1) the One-Call program and 2) the Common Ground Alliance program. A LPL representative chairs the API Damage Prevention Committee. LPL is in the process of preparing a table which is a comparison of the provisions from all the state One-Call programs that affect LPL. LPL would like to "push" the states toward similarity in state One-Call provisions. One-Calls are routed to LPL's headquarters, headquarters determines which District office is involved and forwards the One-Call requests to the appropriate District. Lakehead has a PC computer system which is solely dedicated to managing One-Call activities. One-Call records are located at various LPL pipeline maintenance (PLM) offices. There are 12 locations through out LPL's system that respond to One-Call reports.

195.442(c) Damage prevention program - the operator must identify, on a current basis, persons who normally engage in excavation activities in the area in which the pipeline is located; notify the public and persons who normally engage in excavation activities of the damage prevention program; provide a means of receiving and recording notification of planned excavation activities; provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings; and provide inspection of excavation activities, if the operator believes the pipeline could be damaged by excavation activities.

195.442(c)(3) Damage prevention program - if the operator participates in a public service program, such as a qualified one-call system, then the operator must: provide a means of receiving and recording notification of planned excavation activities.

G-Q48) Does the operator have an adequate damage prevention program?

R48) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q48) Headquarters	X			
Q48) Field	X			
R48) Headquarters			X	
R48) Field	X			

48) Comments: One-Calls are usually handled out of various LPL pipeline maintenance (PLM) offices within each District. LPL relies on the One-Call program to maintain a list of excavators. Whenever LPL receives a request from a third party to cross LPL's lines, LPL tries to obtain a formal written crossing agreement which details the parameters that LPL requires for a crossing.

Are trained/qualified personnel used for pipeline locating & marking?

49) Comments: Lakehead uses only trained company employees to locate and mark lines. Line locating and marking is one of the covered tasks in Lakehead's operator qualification plan. Lakehead has 3 crossing coordinators who have attended the one week course at Staking University in Marysville, MI. These crossing coordinators then conduct field training of other LPL personnel. Vendors go to Lakehead field locations and train personnel on the use of specific line locating equipment.

Liaison with Construction Project and Land-Use Officials (Public Education)

Encroachment around pipelines poses serious safety risks as third parties excavate in proximity to buried pipelines. A strong damage prevention program will provide advance notification of construction plans near the pipeline and will establish communication with the people involved in the project.

195.440 Public Education - each operator shall establish a continuing educational program to enable the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator or the fire, police, or other public officials.

G-Q50) How does the operator implement its continuing education program?

R50) Associated Records?

	Satisfactory	Needs Improvement	N/A	N/C
Q50) Headquarters	X			
Q50) Field	X			
R50) Headquarters			X	
R50) Field	X			

50) Comments: Lakehead's public awareness program is located in Book 1, Sections 04-01-01 and 04-02-01 of Lakehead's O & M manual. After identifying pubic officials that may need notifications, contact is made using mailings, face-to-face meetings and group meetings. Contact information is updated annually. General public awareness is through mailings of brochures, calendars and newspaper advertisements. LPL uses a API public awareness brochure as a multi-language mailing for landowners/tenants. Mailings to landowners/tenants is done annually. Every 3 years LPL tries for face-to-face meetings with groups and individuals who are located outside of LPL's right-of-way boundaries.

G-51) Best Practice:
Does the operator's damage prevention program include pro-active liaison with public construction project and land-use officials, engineers, and contractors?

51) Comments: Lakehead has recently added mailings to planning and zoning directors as part of LPL's program. Presentations are for county officials such as county clerks and zoning personnel.

G-Q52) Best Practice:
Does the operator's damage prevention program include pro-active liaison with local school officials, where the pipeline traverses or is adjacent to, school property?

52) Comments: Lakehead does not have a pro-active company wide program for liaison with school officials. The district level offices have some contact with schools located along LPL's right-of-way. LPL's presentation to schools is focused on school staff members and school administrative personnel.

G-Q53) Best Practice:
Does the operator have a liaison program that includes local developers and construction project officials?

53) Comments: Refer to comments for Q51. LPL does not have a formal program for liaison with land developers, real estate companies or other private land use managers.

G-Q54) Best Practice:
Has the operator reviewed the "Common Ground" Study of One Call Systems and Damage Prevention Best Practices?

54) Comments: LPL is a member of the Common Ground Alliance. LPL has one member of the Common Ground committee. The Common Ground study was reviewed by approximately 6 Lakehead individuals.

G-Q55) Best Practice:
Has the operator compared and measured the best practices against existing damage prevention practices contained in the operator's damage prevention plan?

55) Comments: Lakehead compared LPL's plan to the Common Ground practices and recommendations were forwarded to the District Managers.

G-Q56) Best Practice:
Has the operator implemented any of the best practices in addition to their existing damage prevention activities subsequent to review of the Common Ground Study?

56) Comments: Lakehead has modified their public awareness program based on some of the practices in the Common Ground study. Lakehead now sends two people out to audit One-Call centers. The modifications done to Lakehead's damage prevention program as a result of the Common Ground Study were minor in nature.

G-Q57) Best Practice:
Has the operator improved communication with other stakeholders in damage prevention as a result of the best practices?

57) Comments: Lakehead incorporates the 4 or 5 points on digging/damage prevention in the study. Lakehead looks at damage prevention as a whole process that goes beyond just "call before digging". LPL feels that "call before digging" should include all steps (call in, wait the required time interval, pay close attention to the pipeline company's markers, use safe procedures while digging, etc.) Lakehead has modified their internet website to provide better public awareness.

Field Verification of Facility Response Plan Information		Y	N	N/A
194.111	Is there a copy of the approved Facility Response Plan present? RSPA Tracking Number **865 District 3, 866 District 4, 867 District 5, 868 District 7** Approval Date **2/17/95 Renewal pending via DOT letter dated 3/20/01.** [See Guidance OPA-1]	X		
194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]			X
194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	X		
194.117	Does the operator maintain records for spill response training (including Hazwoper training)? [OPA-5]	X		

OPA Inspection Guidance

OPA-1 - RSPA Tracking Number: This is also known as the "sequence number." It is a four-digit number that OPS HQ assigns to each facility response plan (FRP). If the operator does not know their sequence number, they should look on their copy of the FRP for the sequence number. Also, OPS HQ always puts the sequence number in every plan-related letter to operators.

Copy of approved FRP: Every oil pipeline operator must have an FRP approved by OPS. The operator should be able to produce their OPS plan approval letter. When OPS HQ approves a plan, the approval is valid for five years from the date of the approval letter.

OPA-2 - Names and phone numbers: Operators are required to keep the notification lists in their FRP current. The inspector should examine the notification list in the FRP and spot-check the accuracy of the names and phone numbers when they interview the operator. It is critical to check the Qualified Individual (QI) and Alternate QI data.

OPA-3 - Proof of OSRO contract: Operators whose FRP's state that they are relying on clean-up contractors for spill response are required to have contracts with the oil spill removal organizations (OSRO's) that they cite in the FRP. The inspector should ask to see documentation that the operator has a contract in place with the primary OSRO listed in the FRP.

OPA-4 - Exercise documentation: Operators are required to conduct a variety of spill response exercises under Part 194, and make their exercise records available to OPS for inspection. Inspectors should check to see if the operator lists the date, time, location and names of exercise participants. If the inspector has doubts about whether the operator's exercise documentation is accurate, it should be noted on the inspection form so that OPS HQ can follow up with the operator. The documentation should include annual spill management team tabletop exercises, quarterly internal notification drills, and annual response equipment deployment drills? The drill does not necessarily need to include a pipeline spill scenario, but should test the operator's personnel, equipment, resources, and response strategies needed for responding to a comparable pipeline spill.

OPA-5 - Training records: Operators are required to train their personnel to carry out their individual roles under the FRP. The inspector should spot-check the files of key personnel listed in the FRP to ensure that they have been trained to carry out their duties in a response. Special attention should be given to documenting the safety training required under OSHA's Hazwoper standard (29 CFR 1910.120). Each person involved in a spill response is required under 194.117 to have training commensurate with their duties.

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Date(s): 6-12-01

Unit: BAY CITY

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
Line # 17						
MP 35.80						
Freedom Junction		-2.390	LPL side			
		-2.336	Wolverine side			
	Rect.			4.69	1.00	
MP 28.753						
Jerusalem Road		-1.870				
MP 25.278						
R.R. Crossing		-1.791	-0.762			
MP 20.627						
M/L Valve 20.63-17-V		-2.175				
		Rect.		7.18	3.06	
MP 14.846						
Joslin Lake Road		-1.644				
MP 9.880						
Hill Road		-1.502				
MP 4.662						
Morton Road		-1.444				
MP. 0.000						
Stockbridge Station						
Line 17 into Pump						
	House	-1.318				
Tank #80	N	-4.130				
	S	-6.290				
	E	-6.000				
	W	-4.260				
Tank Relief Line		-5.240				
Booster #2		-1.896				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Unit: Griffith

Date(s): 6-12-01 to 6-18-01

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
Line 6B						
MP 520.000						
Carisle Station						
Valve 519.69-6-PV		-2.080				
Valve 519.70-6-V		-2.190				
	Rect.			21.00	6.02	
MP 515.100		-2.370	-1.250	47.00	5.15	
MP 511.578						
County Rd 300E	6B	-1.147	-0.890			
	6B loop	-1.197	-0.464			
MP 505.523						
C&O R.R.	6B	-0.874	-0.601			
	6B loop	-0.943	-0.480			
MP 500.137						
Forrester Rd	6B	-0.820	-0.673			LPL suspects coating problem here.
	6B loop	-0.836	-0.507			LPL plans to re-coat 100 feet
						of line back on both sides of
						the road. The re-coat should
						be done by August, 2001.
MP 499.350						
Laporte Station						
Valve 6-SDV-1		-1.108				
" 499.39-6-V		-1.041				
" 6-USV-21		-3.410				
	Rect.			68.50	6.75	
MP 493.072						
County Rd 550	6B loop	-1.237	-0.710			
MP 489.059						
Valve 489.14		-1.716				
Trap	6B loop	-1.914				
	Rect.			8.68	4.17	
MP 484.426						
County Rd 200		-1.334	-0.644			
MP 480.490						
Valve 480.49		-1.394				
	Rect			8.30	4.85	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Unit: Griffith
Date(s): 6-12-01 to 6-18-01

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 474.91						
Valve - Deer River,						
West Side		-1.536				
MP 475.191						
Valve - Deer River,						
East Side		-1.518				
MP 465.50						
Griffith Station						
Valve 465.39-6-V		-1.996				
Trap-outgoing	6B	-1.992				
Pipe-incoming		-2.810				
Manifold		-1.486				
Outgoing boosters to Amoco		-1.121				
Valve 465.58-6-V		-2.040				
Booster # 101		-1.148				
Booster #401		-1.141				
Valve 6-UDV-21		-1.127				
	Rect			22.00	6.80	
Tank #71	N	-4.730				
	S	-5.170				
	E	-4.940				
	W	-4.960				
	Rect. 465A			17.99	27.20	
Tank #72	N	-3.150				
	S	-2.820				
	E	-2.960				
	W	-2.920				
Tank #75	N	-3.370				
	S	-3.620				
	E	-2.930				
	W	-3.870				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Date(s): 6-12-01 to 6-18-01
Unit: Griffith

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
Griffith Station (cont.)						
Tank # 77	N	-5.340				
	S	-5.010				
	E	-3.990				
	W	-5.850				
	Rect. 465C			12.00	33.00	
Hartsdale Terminal						
Tank to tank piping		-1.862				
Booster Pump Area		-1.034				
Tank # 1602	N	-3.880				
	S	-3.790				
	E	-4.880				
	W	-2.910				
Tank # 1606	N	-4.070				
	S	-2.590				
	E	-3.940				
	W	-4.830				
Tank # 1609	N	-3.750				
	S	-3.830				
	E	-2.690				
	W	-4.240				
	Rect. C466A			12.40	32.60	
	Rect. C466B			15.10	40.30	
MP 454.703						
Jackson Ave.		-1.404	-1.077			
MP 449.163						
M/L Valve		-1.702				
MP 448.207	Rect. C448			10.50	5.10	
MP 438-398						
Mokena Station						
Valve 151-PCV-11		-1.117	Line 6			
Line to CHICAP		-1.267	Line 6			
Trap-incoming		-1.709	Line 14			
Control Valve		-1.203	Line 14			
Valve 6-SSV-3		-0.861	Line 6			

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: Griffith

Date(s): 6-12-01 to 6-18-01

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
Mokena Station (cont.)						
Valve 6-K-2		-0.830	Line 6			A new rectifier has been
Valve 438.39-6-V		-1.119	Line 6			installed but is not operative
						yet. The rectifier probably will
						be energized about mid-July.
MP 433.070						
Northern Border						
P/L crossing		-1.319				
MP 432.428						
Parker Rd		-2.080	-0.717			
	Rect.					Rectifier down. Suspect hit
						by lighting. LPL will repair.
MP 426.783						
Lockport Station						
Valve 6-SDV-1		-1.518				
" 6-USV-31		-1.312				
" Backpressure		-1.235				
	Rect.			16.04	19.80	
MP 425.448						
Canal Pipe Arch						
	Rect.			9.89	1.96	
Pipe Arch (active side)		-1.098				
(inactive side)		-0.956				
MP 423.008						
M/L valve		-0.910				
MP 412.215						
Napierville Station						
Pipe-incoming		-1.326				
	Rect.			14.80	14.39	
Valve 412.35-6-V		-1.087				
MP 406.823						
M/L Valve		-1.140				
MP 406.780						
M/L valve		-1.179				
MP 404.756	Rect.	C405		15.43	12.10	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: Griffith

Date(s): 6-12-01 to 6-18-01

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 383.090						
Dundee Station						
Valve 6-SSV-1		-1.345				
" 383.16-6-V		-2.650				
" 6-PCV-1		-2.610				
" 6-UDV-2		-1.428				
	Rect. C383			18.30	9.12	
MP 384.00						This station is actually
Burlington Station - Line 14						in the FORT ATKINSON
Sta. Suction Piping		-1.941				unit.
Pumphouse-out		-1.291				
	Rect. FORT-700-CR-384			38.40	14.40	
MP 415.785 - Line 14						
State Rt. 34		-1.293	-0.567			
Walmart Drive						
#1 N		-1.288	-0.667			
#1 S		-1.220	-0.587			
#2 N		-1.230	-0.496			
#2 S		-1.396	-0.652			
#3 N		-1.314	-0.510			
#3 S		-1.311	-0.488			
MP 417.922 - Line 14						
Fox River - N. Side						
Valve 417.92-14-V		-1.089				
MP 417.922 - Line 14						
Fox River - S. Side						
Valve 419.69-14-V		-1.111				
MP 439.313						
Dupage River - N. Side						
Valve 14-439.31-V		-1.934				
MP 440.303						
Dupage River - S. Side						
Valve 14-440.30-V		-2.800				
	Rect. C 440			15.10	5.75	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: Griffith

Date(s): 6-12-01 to 6-18-01

		Field Readings				
	Line	CP, volts		Rectifier		
Line & Location	Size, in.	P/S	Casing	Volts	Amps	Remarks
MP 442.483						
I&M Canal - N. Side						
Valve 14-442.48-V		-1.267				
MP 444.345						
Des Plaines R. - N. Side						
Valve 14-444.35-V		-1.543				
MP 446.230						
Des Plaines R. - S. Side						
Valve 14-446.23-V		-1.172				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: FORT ATKINSON

Date(s): 6-18-01 to 6-21-01

Line & Location	Line Size, in.	Field Readings: CP, volts: P/S	Casing	Rectifier: Volts	Amps	Remarks
MP 368.094 - Line 6A						
Crystal Lake Station						
Valve 6-SSV-1		-2.050				
Pumphouse - Suction		-2.170				
Rect. C368				28.90	16.00	
MP 352.535						
M/L Valve		-2.270				
Rect. C353				13.53	7.10	
MP 345.883						
State Line Rd						
Line 6A		-1.780	-0.417			
" 14		-1.548				
MP 352.330 - Line 14						
Valve 352.33-14-V		-1.675				
MP 341.351						
Walworth Station						
Valve 341.35-6-V		-2.330				
" 341.28-14-V		-3.010				
" 341.43-6-V		-2.430				
Pipe-Control Valve Bldg.		-1.528				
Valve 6-USV-21		-2.950				
Rect. C341				36.90	15.90	
MP 333.750						
Line 6A			-0.405			
" 14		-4.330				
Valve 333.64-14-V		-1.908				
MP 321.278						
Delavan Station						
Valve 321.33-6-BV		-1.082				
Pump house - Discharge		-1.844				
Rect. C321				11.73	3.45	
MP 313.607						
Rock River - S. Side						
Valve 313.40-14-V		-0.995				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: FORT ATKINSON

Date(s): 6-18-01 to 6-21-01

Line & Location	Line Size, in.	CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 312.492						
Rock River - N. Side						
Valve 312.52-6-V		-0.978				
" 14-312.32-V		-0.943				
MP 304.588						
Cambridge Station						
Valve 6-CSV-21		-1.011				
" 6-UDV-31		-2.050				
Sump Tank		-3.550				
Valve 304.58-6-V		-1.182				
Incoming Piping - Line 14		-1.950				
Pump house piping - Line 14		-0.886				
	Rect. CR304			11.20	5.32	
MP 298.705	Rect. C299			24.00	10.10	
MP 292.599						
Waterloo Station						
Valve 292.64-6-BV		-2.100				
Pump house Piping		-3.300				
	Rect. C292			19.68	8.90	
MP 289.698						
M/L Valve - Line 6A		-1.980				
MP 289.701						
M/L Valve - Line 6A		-1.870				
MP 288.572						
Fisch Rd	Rect. CR289			12.00	7.20	
MP 277.899						
Hall Rd						
Line 6A		-1.930	-0.563			
" 14		-2.150				
MP 269.03						
Rio Station						
Valve 268.90-6-V		-2.560				
Pipe		-3.690				
Valve 268.76-14-V		-2.720				
Control Bldg. - Pipe		-2.640				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Date(s): 6-18-01 to 6-21-01

Unit: FORT ATKINSON

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Field Readings CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
Rio Station (cont.)						
Valve 6-USV-21		-1.682				
Sump Tank		-1.971				
	Rect. C269			26.60	11.08	
MP 259.595						
Theil Rd						
Line 6A		-5.780	-0.659			
" 14		-5.660				
	Rect. C260			53.60	11.60	
MP 255.799						
Portage Station						
Valve 255.62-14-V		-2.210				
" 6-SDV-1		-1.795				
Pumphouse Piping		-2.360				
	Rect. C256			41.50	13.80	
MP 245.499						
Douglas Ave.						
Line 6A		-2.090	-0.246			
" 14		-2.050				
MP 242.280						
Valve 242.28-14-V		-1.103				
MP 235.954						
Ember Rd.						
Line 6A		-1.687	-0.241			
" 14		-1.640				
MP 227.520						
Adams Station						
Line 14						
Pumphouse - out		-1.501				
" - in		-4.620				
Trap - out		-5.000				
Trap - in		-18.140				
Line 6A						
Valve 6-CSV-11		-2.810				
" 6-UDV-21		-2.420				
Sump Tank		-3.870				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: FORT ATKINSON

Date(s): 6-18-01 to 6-21-01

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
Adams Station	(cont.)					
Line 6A						
Trap - out			-15.280			
Trap - in			-17.00			
	Rect.	C227		47.70	19.04	
MP 220.777						
8th Drive						
Line 6A		-2.470	-0.621			
" 14		-2.600				
MP 214.197						
Cottonville Station						
Cross Bond						
Line 6A		-1.564				
" 14		-1.565				
Pumphouse - Suction		-1.064				
	Rect.	C214		96.20	32.10	
MP 211.654						
Big Flats	Rect.	C212		86.30	23.50	
MP 203.080						
Wisconsin River - S. Side						
M/L Valve - Line 6A		-1.438				
Valve 203.08 - 14 - V		-1.310				
MP 201.241						
Wisconsin River - N. Side						
M/L Valve - Line 6A		-2.280				
Valve 201.15 - 14 - V		-2.080				
MP 201.781						
County Rd Z						
Line 6A		-1.426	-0.911			
" 14		-2.030				
MP 195.289						
Seneca Rd.						
Line 6A		-1.099				
" 14		-2.040				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Unit: FORT ATKINSON

Date(s): 6-18-01 to 6-21-01

Line & Location	Line Size, in.	Field Readings CP, volts P/S	Casing	Rectifier Volts	Amps	Remarks
MP 190.636						
Vesper Station						
Valve 190.63-6-V		-1.332				
Piping - in		-3.210				
PCV Bldg. piping		-1.286				
Valve 6-UDV-21		-1.337				
Sump Tank		-1.342				
	Rect.	C190		35.20	29.60	
MP 188.300						
Valve 188.36-14-V		-1.108				
MP 186.340						
Valve 186.34-14-V		-1.731				
	Rect.	C186		58.20		
MP 173.300						
Marshfield Station						
Valve 173.31-6-BV		-1.085				
" 173.29-14-V		-1.212				
Pumphouse - Suction		-1.111				
	Rect.	C173A				Down, hit by lighting. LPL will repair
	"	C173B		13.57	15.85	
MP 165.831						
M/L Valve - Line 6A		-1.376				
MP 165.907						
M/L Valve - Line 6A		-1.283				
MP 163.660						
Valve 163.66-14-V		-1.029				
MP 161.086						
Spencer	Rect.	C161		37.40	18.10	
MP 153.102						
County Rd K						
Line 6A		-1.538	-0.699			
" 14		-1.632				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: FORT ATKINSON

Date(s): 6-18-01 to 6-21-01

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 148.541						
Owen Station						
Line 6A						
Valve 148.78-6-BV		-1.279				
PCV Bldg piping		-1.377				
Valve 6-UDV-11		-1.572				
Sump tank		-1.803				
Line 14						
Piping-Discharge		-1.043				
Valve manifold area		-1.894				
	Rect.	CR148		19.78	18.90	
MP 141.581						
Bruchslager Rd.						
Line 6A		-4.990				
" 14		-4.960				
	Rect.	CR142		13.47	5.45	
MP 135.555						
Lublin Station						
Valve 135.55-6-BV		-1.565				
" 135.42-14-V		-1.724				
Pumphouse-Suction		-2.600				
	Rect.	C136		19.19	23.26	
MP 124.326						
M/L Valve-Line 6A		-1.859				
MP 124.180						
Valve 124.18-14-V		-2.530				
	Rect.	C124		34.70	14.15	
MP 113.161						
Sheldon Station						
Valve 113.16-6-V		-1.448				
Piping		-3.940				
Valve 113.23-6-V		-3.230				
PCV Bldg. piping		-1.237				
Sump Tank		-1.976				
Valve 113.03-14-V		-1.305				
	Rect.	CR113		24.50	16.02	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Unit: FORT ATKINSON

Date(s): 6-18-01 to 6-21-01

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 110.020						
Valve 110.02-	14-V	-1.585				
	Rect. C110			14.07	3.55	
MP 99.250						
Ladysmith Station						
Valve 99.10-	14-V	-1.795				
Pumphouse - Discharge		-1.952				
	Rect. C99			19.54	7.80	

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Unit: SUPERIOR

Date(s): 6-21-01 to 6-22-01

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 93.946						
County Rd A						
Line 6A		-1.959	-0.668			
" 14		-1.940				
MP 89.000						
Chippewa River - S. Side						
Valve G88.91-14-V		-0.874				
MP 88.178						
Chippewa River - N. Side						
Valve 88.18-6-V		-0.895				
" G88.06-14-V		-1.068				
MP 80.995						
County Rd C		-3.191				
Line 6A		-3.570				
" 14						
	Rect. C081			28.05	9.65	
MP 70.088						
Edgewater Station						
Valve 70.09-6-V		-1.562				
PCV Bldg. piping		-2.720				
Valve 6-USV-11		-2.194				
Sump Tank		-1.654				
Line 14						
Inlet area piping		-3.175				
Pumphouse - piping		-1.585				
MP 63.348						
Line 6A		-4.150	-4.300			LPL plans more testing here.
" 14		-5.360				
	Rect. C063			47.20	12.40	
MP 61.800						
Stone Lake Station						
Valve C61.84-6-BV		-1.072				
Pumphouse - Discharge		-7.950				
	Rect. C061			58.50	5.80	

Optional Field Data Collection Form for Liquid Inspection

Page: 2 of 3

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline

Unit: SUPERIOR

Date(s): 6-21-01 to 6-22-01

Line & Location	Line Size, in.	Field Readings: CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 55.576						
M/L Valve - Line 6A		-1.566				
Valve G55.31-14-V		-1.386				
MP 55.650						
Valve C55.65-6-V		-1.823				
MP 53.411						
Valve G53.19-14-V		-1.501				
MP 41.235						
Minong Station						
Valve 6-SSV-1		-2.457				
" 6-UDV-41		-2.198				
Sump Tank		-2.011				
	Rect. C041			76.00	9.90	
MP 35.000						
St. Croix River - S. side						
Valve G34.53-14-V		-1.332				
Valve 33.965 - 6A		-0.990				
MP 33.125						
St. Croix River - N. side						
Valve C33.13-6-V		-2.928				
" G32.28-14-V		-2.345				
	Rect. C033			37.89	7.95	
MP 30.900						
Line 6A		-2.758	-0.027			LPL plans more testing here.
" 14		-2.822				
	Rect. C031			65.70	4.25	
MP 23.620						
Hawthorne Station						
Valve 6-SSV-1		-1.421				
Pumphouse - Discharge		-1.888				
MP 14.609						
County Rd B						
Line 6A		-1.294	-0.820			
" 14		-1.361				

Optional Field Data Collection Form for Liquid Inspection

NOTES - FIELD INSPECTION

Company: Lakehead Pipeline
Unit: SUPERIOR

Date(s): 6-21-01 to 6-22-01

Line & Location	Line Size, in.	Field Readings CP, volts P/S	CP, volts Casing	Rectifier Volts	Rectifier Amps	Remarks
MP 9.688						
Line 6A		-3.753	-0.723			
" 14		-3.657				
	Rect. C0/0			12.49	8.80	
MP 2.000						
Nemadji River - S. side						
Valve 61.83-14-V		-1.265				
MP 1.975						
Nemadji River - N. side						
Valve 61.18-14-V		-1.350				

Segment Identification and Completeness Check Inspection

Final Post-Inspection Report

Report Issue Date:	March 22, 2002 (original draft issued February 28, 2002)
Operator:	Enbridge (US), Inc. For Enbridge Energy LP (Former Lakehead System) For Enbridge Pipelines (Toledo) Inc. Enbridge Pipelines (North Dakota) LLC
Corporate Address:	Enbridge (US), Inc. For Enbridge Energy LP (Former Lakehead System) For Enbridge Pipelines (Toledo) Inc. 1100 Louisiana Street, Suite 3300 Houston, TX 77002-5217 Enbridge Pipelines (North Dakota) LLC 2625 Railway Avenue Minot, ND 58703
Operator ID Number(s):	11169 Enbridge Energy LP (Former Lakehead Sys.) 31448 Enbridge Pipelines (Toledo) Inc. 15774 Enbridge Pipelines (North Dakota) LLC
Date of Inspection:	February 26-27, 2002
Location of Inspection:	Enbridge (US) Inc. 21 West Superior Street Duluth, MN 55802-2067
Primary Contact:	John Sobojinski, Manager, U.S. Compliance & Risk Management
Primary Contact Phone and Fax Numbers:	Phone: (218) 725-0505 Fax: (218) 725-0149

Operator Personnel Participants:

Primary Contact: John Sobojinski	Manager, US Compliance & Risk Management	218-715-0505	john.sobojinski@enbridge-us.com
Jay Johnson	Operations Services Coordinator	218-725-0512	jay.johnson@enbridge-us.com
Brad S. Smith	Supervisor, Integrity Process	780-420-8607	brad.smith@cnpl.enbridge.com
David Weir	Sr. Operational Risk Mgmt Analyst	780-420-8145	david.weir@cnpl.enbridge.com
Barry Power	Environmental Analyst	218-725-0143	barry.power@enbridge-us.com
Dana Slade	Sr. Environmental Analyst	218-725-0152	dana.slade@enbridge-us.com

OPS Inspection Team Representatives:

Dave Barrett (Central Region) - Lead Inspector
Byron Coy (Eastern Region)
Steve Stout (Cycla Corporation)

Inspection Objectives: The purpose of this inspection was to assure Enbridge has identified segments on its pipelines that can affect High Consequence Areas as required by 195.452 (b) (1) (I). This inspection also included a summary level review of the operator's Baseline Assessment Plan and Integrity Management Framework to ascertain a level of progress in meeting the Integrity Management Program requirements in 195.452 (f). The results from both the segment identification and completeness check portions of this inspection will be used to plan and schedule the upcoming Comprehensive Integrity Management Program Review.

Summary of Segment Identification Process:

The OPS approach to inspect Enbridge's identification of pipeline segments that could affect HCAs involved two steps. The first step was to review the technical approach used to define these segment boundaries, including the justifications for any assumptions used in the segment determination. The second step was to verify that Enbridge performed the segment identification effort in a manner consistent with its described approach. In conducting this verification, the OPS inspection team examined a limited number of Enbridge's segment identification results for a variety of different specific locations where the pipeline intersected, or was in close proximity to, different types of HCAs. OPS may conduct more in-depth reviews of the segment identification process and conduct additional verification of segment locations during the Comprehensive Integrity Management Program inspections.

Enbridge has downloaded the HCA shape file information into its Geographic Information System (GIS) and has overlaid its pipeline data on the HCA maps to identify portions of its pipeline that are located within or near the HCA boundaries. The following HCAs were identified by Enbridge that were not in NPMS:

1: The city of Rapid River, MI was identified as an Other Populated Area using the corporate municipal boundary as the boundary of the HCA.
2: Fifteen Navigable Water Crossings, per 49 CFR 194 were identified that were not in NPMS.
3: Drinking Water HCAs in the states of NY and MI were not in NPMS.

Enbridge used a manual approach to annotate segments that are located within, or that could affect, HCAs. The intersecting and "could affect" segments were identified from a review of hard copy maps printed from its GIS overlay and manually entered into a spreadsheet for further analysis. The spreadsheet was spatially linked to the GIS files for each pipeline so that Enbridge personnel could view the results of the manual "could affect" analysis by clicking on the pipeline segment within its GIS mapping system.

The process and methodology used by Enbridge to perform its "could affect" analysis is described below.

Overland Spread

Enbridge calculated a radial flow distance from the pipeline using a strophoid (teardrop) shaped spread "footprint." The shape was uniform and was not varied based on topography. The length was approximately twice as long as the width. The shape is defined by the formula r=c*cos(2?)/cos(?), where c=length of major axis and r=radial distance at any given angle. At ?=0, r=c. The length of the major axis was calculated using the equation: $c=[2(V/H)/(4-p)]^{1/2}$ where V=Volume of spill and H=average thickness of pool. Key assumptions were a "detention dominant" spill scenario with a spill volume of 20,000 bbl and a pool thickness of 1 inch. This resulted in a spread reach of 1770 feet. This 1770 feet distance was placed around the pipeline centerline as an initial screening "buffer zone." This buffer zone was depicted on the mapping system and hard copy maps were printed for each pipeline section. Any HCA that was located within the 1770' buffer zone was manually reviewed in more detail. A case-by-case qualitative topographical analysis was performed. Enbridge used USGS quad maps and an off-the-shelf software tool to assist in identifying topographical features and elevation profiles in its analysis. If the HCA was located uphill of the pipeline, then the pipeline was not designated as a "could affect" segment. If the topography indicated that the HCA was downhill of the pipeline, then the segment was determined to be a "could affect" segment. Simply put, only HCAs that were both (1) within the 1770' buffer zone and, (2) were on the downhill side of the pipeline, were designated as "could affect" segments.

Tanks

Enbridge performed a similar analysis for tank spills. Spill volume was assumed to be the maximum fill capacity of the largest tank at a facility. No credit was taken for dikes or spill containment and the entire spill volume was used in calculating the spread distance from the tank.

Spray Analysis

Enbridge used another buffer zone for spray analysis. They selected 660 feet as a buffer zone for liquid spray affects. The buffer zone selected was based on two Enbridge events in which oil spray from a punctured pipeline reached 300 to 500 feet from the pipeline. Any segment that had an HCA located within the 660' spray buffer, regardless of topography, was determined to be a segment that could affect the HCA.

Water Transport

Enbridge considered water transport to HCAs. Enbridge calculated different "could affect" distances for water transport for different water flow conditions labeled (1) static water, (2) low energy open channel flow, (3) moderate energy open channel flow, and (4) high energy open channel flow. For open channel flow, Enbridge used Chezy's Equation and Manning's Equation to determine possible flow distances. Significant input variables included mean flow velocity, thickness of oil layer, hydraulic radius, hydraulic gradient, response time to contain the spill, and the Manning roughness constant. The appropriateness of the specific values used for the calculations was not verified during the inspection. Enbridge used USGS quad maps and an off-the-shelf software tool to assist in identifying hydraulic gradient of the streams. Pool thickness was assumed to be 0.01 feet. Response time was assumed to be 3 hours based on Enbridge's emergency procedures and experience. The stream mean flow velocity was doubled for the calculation as a conservative means to account for abnormal high flow conditions. The results were a spill reach of 0.9 miles for a low energy stream, 4.4 miles for a moderate energy stream, and 11.9 miles for a high energy stream.

Combination Transport Mechanisms

If a water transport mechanism was located within 660'of a pipeline (Spray), or within 1770' downhill of a pipeline (Overland Spread), then the spill was analyzed to extend beyond the initial buffer zone for the additional distances specified in the water transport analysis.

Air Dispersion

Enbridge has some 18", 20", 26" and 30" lines used for batch service to transport Natural Gas Liquids (NGL) in the 600 to 900 psi pressure range. Enbridge used a 660' buffer zone for possible liquid release assuming that a large NGL release would not all instantaneously vaporize. In addition, Enbridge used a ½ mile buffer zone for air dispersion. Drinking water HCAs that were farther away than 660' were determined to not be affected by an HGL line due to vapor hazards.

Summary of Completeness Check: At the time of the inspection, Enbridge had not completed the Baseline Assessment Plans for its operational systems.

The review and discussion of Enbridge's individual program elements showed that Enbridge has not yet developed it Integrity Management Program to address most of the program elements in 452 (f). Some company programs are in place and could be integrated into an adequate Integrity Management Program that successfully implements the required program elements. However, the IM Framework has not been developed, with the exception of Segment Identification (required element #1).

Specifically, Enbridge has not made substantial progress in its effort to perform a risk analysis of its "could affect" segments and integrate the relative risk ranking into its Baseline Assessment Plan.

OPS Feedback: The OPS inspection team provided the following feedback to Enbridge during the exit interview.

1. Enbridge assumed a 20,000 bbl spill volume based on the fact that this volume was larger than 99% of their historical spills. However, the largest Enbridge spill occurred in 1991 and released 40,500 bbl of crude oil. Therefore, the use of a 20,000 bbl spill volume may not be conservative.
2. The Enbridge overland spread analysis assumed that the spill volume was evenly distributed at an average thickness of 1 inch. Enbridge did not have a technical justification for this assumption other that they believed that it was conservative.
3. The maximum reach is highly influenced by the relative dimensions of the spread pool. The strophoid (teardrop) shape was approximately half as wide as it was long. A spill in topography such as ravines could result in spill pools that are significantly longer and narrower than the "footprint" used in the Enbridge analysis.
4. The ½ mile buffer zone for air dispersion of NGL was based on the evacuation distance contained in the DOT emergency response handbook. Enbridge did not have a technical justification for this buffer distance.
5. Enbridge had a general note in its manual regarding the need to update HCA information. However, it did not provide specific procedures, review periodicity, responsibilities, or data sources for the HCA update process. The process to update HCA Segment Identification needs to be elaborated.
6. The process and procedures did not specifically require that all changes to the IM Program (specifically changes to the Segment Identification process or results) be documented along with justification or basis for the changes.
7. Enbridge needs to provide IM Program documentation for each required element of the IM Program required by the rule. If existing processes or procedures are to be used, they should be updated to meet all rule requirements and the IM Framework should updated to reference or mandate use of existing processes to meet IM requirements.
8. The Baseline Assessment Plan schedule of assessments should include HCA segment prioritization based on risk ranking by March 31, 2002.

Potential Noteworthy Practices: None noted.

February 28, 2002

OPS: Integrity Management Quick Hit Information Discussions

Enbridge (U.S.) Inc. For Enbridge Energy, Limited Partnership [Former Lakehead System]

System Mileage That Could Affect High Consequence Areas	Data
Has operator identified all pipeline segments that could affect a high consequence area? [see 195.452(b)(i)]	Yes _X_ No _
Total mileage within high consequence areas (HCAs are defined in 195.450 (commercially navigable waterways, high population areas, and other populated areas) and 195.6 (unusually sensitive areas))	325.3
Total mileage outside HCAs that could affect HCAs	370.9
Total mileage that "could affect" HCAs (sum of previous two lines)	696.3
Total mileage within high consequence areas determined to not affect the HCA	0

System Components Other than Line Pipe That Could Affect HCA	Data
Total number of terminals, pump stations, or other major facilities that "could affect"	4 terminals

System Mileage	Data
Total number of miles operated in interstate commerce	3,307.71
Total number of miles operated in intrastate commerce	
Total miles of pipe in low stress operation (jurisdictional)	
Total miles of pipe in low stress operation (non-jurisdictional)	
Total number of miles operated offshore	0
Total number of miles operated onshore	3,307.71

Baseline Integrity Assessments Conducted *	Data
Total baseline mileage assessed to date? (Note date data is collected__________)	
Percentage of "could affect" mileage for which baseline assessments have been completed to date?	
Pressure Testing	
Baseline mileage inspected by pressure testing	
Other Assessment Techniques, including direct assessment	
Baseline mileage inspected by other assessment techniques (excluding pressure testing and in-line inspection)	

February 28, 2002

* Note: Some or all of this data may not be available at the time the Segment Identification and Completeness Check inspections are conducted. If not available at this time, it will be obtained during the Comprehensive Program Reviews.

February 28, 2002

OPS: Integrity Management Quick Hit Information Discussions

Enbridge (U.S.) Inc. For Enbridge Pipelines (Toledo) Inc.

System Mileage That Could Affect High Consequence Areas	**Data**
Has operator identified all pipeline segments that could affect a high consequence area? [see 195.452(b)(i)]	Yes _X_ No _
Total mileage within high consequence areas (HCAs are defined in 195.450 (commercially navigable waterways, high population areas, and other populated areas) and 195.6 (unusually sensitive areas))	3.0
Total mileage outside HCAs that could affect HCAs	3.3
Total mileage that "could affect" HCAs (sum of previous two lines)	6.3
Total mileage within high consequence areas determined to not affect the HCA	0

System Components Other than Line Pipe That Could Affect HCA	**Data**
Total number of terminals, pump stations, or other major facilities that "could affect"	0 terminals

System Mileage	**Data**
Total number of miles operated in interstate commerce	35.80
Total number of miles operated in intrastate commerce	
Total miles of pipe in low stress operation (jurisdictional)	
Total miles of pipe in low stress operation (non-jurisdictional)	
Total number of miles operated offshore	0
Total number of miles operated onshore	35.80

Baseline Integrity Assessments Conducted *	**Data**
Total baseline mileage assessed to date? (Note date data is collected___________)	
Percentage of "could affect" mileage for which baseline assessments have been completed to date?	
Pressure Testing	
Baseline mileage inspected by pressure testing	
Other Assessment Techniques, including direct assessment	
Baseline mileage inspected by other assessment techniques (excluding pressure testing and in-line inspection)	

* Note: Some or all of this data may not be available at the time the Segment Identification and Completeness Check

inspections are conducted. If not available at this time, it will be obtained during the Comprehensive Program Reviews.

February 28, 2002

OPS: Integrity Management Quick Hit Information Discussions

Enbridge (U.S.) Inc. For Enbridge Pipelines (North Dakota) LLC

System Mileage That Could Affect High Consequence Areas	**Data**
Has operator identified all pipeline segments that could affect a high consequence area? [see 195.452(b)(i)]	Yes ____ No _
Total mileage within high consequence areas (HCAs are defined in 195.450 (commercially navigable waterways, high population areas, and other populated areas) and 195.6 (unusually sensitive areas))	41.2
Total mileage outside HCAs that could affect HCAs	29.0
Total mileage that "could affect" HCAs (sum of previous two lines)	70.2
Total mileage within high consequence areas determined to not affect the HCA	0

System Components Other than Line Pipe That Could Affect HCA	**Data**
Total number of terminals, pump stations, or other major facilities that "could affect"	4 terminals

System Mileage	**Data**
Total number of miles operated in interstate commerce	622.60
Total number of miles operated in intrastate commerce	
Total miles of pipe in low stress operation (jurisdictional)	
Total miles of pipe in low stress operation (non-jurisdictional)	
Total number of miles operated offshore	0
Total number of miles operated onshore	622.60

Baseline Integrity Assessments Conducted *	**Data**
Total baseline mileage assessed to date? (Note date data is collected__________)	
Percentage of "could affect" mileage for which baseline assessments have been completed to date?	
Pressure Testing	
Baseline mileage inspected by pressure testing	
Other Assessment Techniques, including direct assessment	
Baseline mileage inspected by other assessment techniques (excluding pressure testing and in-line inspection)	

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February 28, 2002

Reviews.

February 28, 2002

OPS: Integrity Management Quick Hit Information Discussions

Enbridge (U.S.) NGL Lines
note that this mileage is included in the system mileages reported above

System Mileage That Could Affect High Consequence Areas	Data
Has operator identified all pipeline segments that could affect a high consequence area? [see 195.452(b)(i)]	Yes X No
Total mileage within high consequence areas (HCAs are defined in 195.450 (commercially navigable waterways, high population areas, and other populated areas) and 195.6 (unusually sensitive areas))	72.95
Total mileage outside HCAs that could affect HCAs	229.45
Total mileage that "could affect" HCAs (sum of previous two lines)	302.40
Total mileage within high consequence areas determined to not affect the HCA	0

System Components Other than Line Pipe That Could Affect HCA	Data
Total number of terminals, pump stations, or other major facilities that "could affect"	N/A

System Mileage	Data
Total number of miles operated in interstate commerce	968.25
Total number of miles operated in intrastate commerce	
Total miles of pipe in low stress operation (jurisdictional)	
Total miles of pipe in low stress operation (non-jurisdictional)	
Total number of miles operated offshore	0
Total number of miles operated onshore	968.25

Baseline Integrity Assessments Conducted *	Data
Total baseline mileage assessed to date? (Note date data is collected__________)	
Percentage of "could affect" mileage for which baseline assessments have been completed to date?	
Pressure Testing	
Baseline mileage inspected by pressure testing	
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February 28, 2002

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February 28, 2002

OPS: Integrity Management Quick Hit Information Discussions

Entire Enbridge System (Does not double count NGL Lines)

System Mileage That Could Affect High Consequence Areas	**Data**
Has operator identified all pipeline segments that could affect a high consequence area? [see 195.452(b)(i)]	Yes ____ No _
Total mileage within high consequence areas (HCAs are defined in 195.450 (commercially navigable waterways, high population areas, and other populated areas) and 195.6 (unusually sensitive areas))	ND 41.2 US M/L 325.3 Toledo 3.3
Total mileage outside HCAs that could affect HCAs	403.2
Total mileage that "could affect" HCAs (sum of previous two lines)	772.7
Total mileage within high consequence areas determined to not affect the HCA	0

System Components Other than Line Pipe That Could Affect HCA	**Data**
Total number of terminals, pump stations, or other major facilities that "could affect"	8 terminals

System Mileage	**Data**
Total number of miles operated in interstate commerce	4001.35
Total number of miles operated in intrastate commerce	
Total miles of pipe in low stress operation (jurisdictional)	
Total miles of pipe in low stress operation (non-jurisdictional)	
Total number of miles operated offshore	0
Total number of miles operated onshore	4001.35

Baseline Integrity Assessments Conducted *	**Data**
Total baseline mileage assessed to date? (Note date data is collected__________)	
Percentage of "could affect" mileage for which baseline assessments have been completed to date?	
Pressure Testing	
Baseline mileage inspected by pressure testing	
Other Assessment Techniques, including direct assessment	
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February 28, 2002

Reviews.

Segment Identification and Completeness Check Inspection

Final Post-Inspection Report

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Corporate Address:	Enbridge (US), Inc. For Enbridge Energy LP (Former Lakehead System) For Enbridge Pipelines (Toledo) Inc. 1100 Louisiana Street, Suite 3300 Houston, TX 77002-5217 Enbridge Pipelines (North Dakota) LLC 2625 Railway Avenue Minot, ND 58703
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Primary Contact Phone and Fax Numbers:	Phone: (218) 725-0505 Fax: (218) 725-0149

Operator Personnel Participants:

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452 (f). Some company programs are in place and could be integrated into an adequate Integrity Management Program that successfully implements the required program elements. However, the IM Framework has not been developed, with the exception of Segment Identification (required element #1).

Specifically, Enbridge has not made substantial progress in its effort to perform a risk analysis of its "could affect" segments and integrate the relative risk ranking into its Baseline Assessment Plan.

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5. Enbridge had a general note in its manual regarding the need to update HCA information. However, it did not provide specific procedures, review periodicity, responsibilities, or data sources for the HCA update process. The process to update HCA Segment Identification needs to be elaborated.
6. The process and procedures did not specifically require that all changes to the IM Program (specifically changes to the Segment Identification process or results) be documented along with justification or basis for the changes.
7. Enbridge needs to provide IM Program documentation for each required element of the IM Program required by the rule. If existing processes or procedures are to be used, they should be updated to meet all rule requirements and the IM Framework should updated to reference or mandate use of existing processes to meet IM requirements.
8. The Baseline Assessment Plan schedule of assessments should include HCA segment prioritization based on risk ranking by March 31, 2002.

Potential Noteworthy Practices: None noted.

Enbridge Pipeline Integrity Management Inspection
Executive Summary

Inspection Date(s):	May 12-16, 2003 (Week 1) June 2-6, 2003 (Week 2)
Location:	Superior, WI
Lead Inspector:	Dave Barrett (OPS Central Region)
Operator Representative:	Jay Johnson, Compliance Coordinator
Executive Contact:	John Sobojinski, Manager, Compliance & Risk Management

System Overview
Enbridge US operates a total of 4000 pipeline miles of which 1088 miles are could affect HCA miles. Enbridge transports crude and NGL from the Canadian/North Dakota (near Neches, ND) border to the Canadian/Michigan border (near Marysville, MI), including lines to the Chicago area. Enbridge will have assessed 64% of their HCA could affect mileage by September 30, 2004.

Integrity Management Program - Summary Conclusions
Program Strengths
1. Enbridge=s Integrity Management Program (IMP) had the strong support of corporate management.
2. Enbridge had a well documented IMP.
3. Enbridge had a strong defect management program.

Most Significant IM Program Concerns/Issues
1. Segment identification had not been performed on the TERRACE III line prior to placing the line in service.
2. Several 180 day discovery dates were missed due to delayed ILI vendor reporting. These included: Line 5 Bay City to Sarnia, Line 3 Gretna to Clearbrook, and Line 2 Gretna to Clearbrook.
3. The IMP did not include requirement for incorporating new could affect segments into the BAP within 1 year and performing assessment within 5 years (' 195.452(d)(3)(ii)).
4. The IM manual permitted the use of techniques other than Section 451.7 of ASME/ANSI B31.4 to determine the amount of immediate repair pressure reduction. In addition, the timeliness of engineering evaluations to determine the pressure reduction was not addressed.
5. In one case, several anomalies identified by ILI were excluded from categorization on the basis that they had previously been remediated. It was later determined the anomalies had not been remediated and were categorized as 180 day repairs with the date of discovery being when the error was recognized. It appeared that Enbridge did not have firm knowledge of where repairs had been made and the anomalies were not remediated in a timely manner.
6. The inspection team noted that the FPP approach to BAP development did not appear to directly include consideration of data that was not directly related to a defect. This included the 195.452(e)(1) required AExisting or projected activities in the area@ factor (3rd party damage), use of Cathodic Protection data, and Anon-pipe@ issues such as flange and fitting leaks.
7. Integration of information/risk analysis (195.452(g)) results does not appear to have a central role in the overall evaluation of integrity challenges.

Significant Pipeline Integrity Issues and Insights
1. HCA could affect segments are identified through a manual process that is not well documented. This lack of documentation makes repeatability of results difficult. It also makes review and validation of results difficult.
2. The calculated release volume for a Cohasset, MN release was less than the actual release.
3. Impact on Business risk factor weighted higher than human or environment factors.
4. Updates to the Risk Model were not being made in a timely manner. E.g., the Cass Lake to Deer River assessment was performed in 2001, but assessment related factors had not been updated.
5. Enbridge needs to validate the 3 hour response time assumed for stream flow transport.
6. Enbridge needs to validate the use of 2 times the mean stream flow for stream flow transport.

1. IM Performance Related Data	Data	Explanations or Notes
1a. Operator		
1b. Pipeline System(s)		
1c. Total Systemwide Mileage	3350	
1d. Operator ID Number(s)	11169/31448	Lakehead/Toledo
1e. Date (for which data is valid)	12/31/2002	
2. IM Program Mileage that Could Affect High Consequence Areas (HCAs)		
2a. Operational Mileage within HCAs	565.95	Removed ENB ND mileage
2b. Operational Mileage within HCAs Determined to Not Affect HCAs	0	
2c. Operational Mileage Outside HCAs that Could Affect HCAs	468.21	Removed ENB ND mileage
2d. Idle/Non-operational Lines Included in Baseline for Later Eval	0	
2e. Total mileage that "could affect" HCAs (2a - 2b + 2c + 2d)	1034.16	
3. System Components Other than Line Pipe That Could Affect HCAs		
3a. Total number of tanks	82	
3b. Total Tank Storage Capacity (bbl)		
3c. Total number of terminals	5	
3d. Total number of pump stations		
3e. Other major facilities		
4. Systemwide Mileage Breakdown		
4a. Total number of miles operated in interstate commerce	3350	
4b. Total number of miles operated in intrastate commerce	0	
4c. Total number of miles operated offshore	0	
4d. Total number of miles operated onshore	3350	
5a. Interstate Mileage by State (List federal offshore as separate state)		
Federal Offshore		
Alabama		
Alaska		
Arizona		
Arkansas		
California		
Colorado		
Connecticut		
Delaware		
District of Columbia		
Florida		
Georgia		
Hawaii		
Idaho		
Illinois	235	
Indiana	60	
Iowa		
Kansas		
Kentucky		
Louisiana		
Maine		
Maryland		
Massachusetts		
Michigan	813	
Minnesota	1244	1147 + 97 (includes Terrac
Mississippi		
Missouri		
Montana		
Nebraska		
Nevada		
New Hampshire		

New Jersey	
New Mexico	
New York	23
North Carolina	
North Dakota	140
Ohio	
Oklahoma	
Oregon	
Pennsylvania	
Rhode Island	
South Carolina	
South Dakota	
Tennessee	
Texas	
Utah	
Vermont	
Virginia	
Washington	
West Virginia	
Wisconsin	835 822 + 13 (includes Terrace
Wyoming	
Puerto Rico	
Guam	
US Virgin Islands	
5b. Intrastate Mileage by State (List federal offshore as separate state)	0
Federal Offshore	
Alabama	
Alaska	
Arizona	
Arkansas	
California	
Colorado	
Connecticut	
Delaware	
District of Columbia	
Florida	
Georgia	
Hawaii	
Idaho	
Illinois	
Indiana	
Iowa	
Kansas	
Kentucky	
Louisiana	
Maine	
Maryland	
Massachusetts	
Michigan	
Minnesota	
Mississippi	
Missouri	
Montana	
Nebraska	
Nevada	

New Hampshire	
New Jersey	
New Mexico	
New York	
North Carolina	
North Dakota	
Ohio	
Oklahoma	
Oregon	
Pennsylvania	
Rhode Island	
South Carolina	
South Dakota	
Tennessee	
Texas	
Utah	
Vermont	
Virginia	
Washington	
West Virginia	
Wisconsin	
Wyoming	
Puerto Rico	
Guam	
US Virgin Islands	

6. Total Systemwide Mileage by Commodity Transported

6a. Total number of miles in crude oil service	3908	
6b. Total number of miles in refined products service (non-HVL)	0	
6c. Total number of miles in batch service involving products or HVL's		
6d. Total number of miles in HVL service	0	
6e. Total number of miles in CO2 service	0	

7. Baseline Integrity Assessment Plan

7a. Baseline Assessment Mileage that Could Affect HCAs	1086	
7b. Deferred Baseline Assessment Mileage (e.g., Idle Lines)	N/A	
7c. Total HCA Baseline Mileage to be Assessed by 3/31/08	1086	
7d. Other Mileage Being Assessed Not Included in Baseline Mileage	2228	
7e. Systemwide Mileage to be assessed in conjunction w/ Baseline	3314	
7f. Systemwide Mileage by Assessment Method		
High Resolution MFL	2592	
Standard Resolution MFL	0	
UT Compression Wave	612.4	
UT Shear Wave	890	CD tool; 2000 - 2002
Geometry, Caliper, or Deformation	3314	
Transverse MFL Tool	23	
Other ILI Tool	0	
Subpart E Hydro	0	
Subpart E Hydro supplemented with "Spike" test	0	
"Spike" Hydro test	0	
Other Technology (not ILI or Hydro)	0	

8. Baseline Integrity Assessment Completion Status

8a. Mileage that Could Affect HCAs with Completed Baseline Assessment	338	
8b. "High Risk" Mileage w/ Completed Assessment	262	(in top 50% of HCA segmer
8c. Systemwide Mileage with Completed Assessment	1013	
8d. Completed Mileage by Assessment Method		
High Resolution MFL	883	

Standard Resolution MFL	0	
UT Compression Wave	326	
UT Shear Wave	890	CD tool; 2000 - 2002
Geometry, Caliper, or Deformation	1232	
Transverse MFL Tool	23	
Other ILI Tool	0	
Subpart E Hydro	0	
Subpart E Hydro supplemented with "Spike" test	0	
"Spike" Hydro test	0	
Other Technology (not ILI or Hydro)	0	
9. Reassessment Plans		
9a. Mileage that has been re-assessed after completion of baseline	0	
9b. Average planned reassessment interval	5	
9c. Mileage planned for reassessment interval greater than 5 years	1488	5yr interval will be used or a
10. Repairs & Pressure Test Experience (as of the start of IM Program)		
In-Line Inspection		
10a. Number of Immediate Repair Conditions addressed	0	
10b. Number of 60 Day Conditions addressed	4	
10c. Number of 180 Day Conditions addressed	56	
10d. Number of other anomalies repaired or mitigated	6	
Hydro		
10e. Number of pressure test failures experienced		
10f. Number of test sections that experienced multiple failures		
10g. Number of test sections that experienced pressure reversals		
11. Preventive and Mitigative Measures to Protect HCAs		
11a. # of EFRDs installed		
11b. # of Leak Detection System enhancements implemented		
11c. # of other preventive & mitigative measures implemented		
12. Leak and Failure History by Cause		
12a. External Corrosion		
1990-1995 Number of Leaks	10	
1990-1995 Total Volume Released (bbl)	20	
1996-2000 Number of Leaks	4	
1996-2000 Total Volume Released (bbl)	5150	
2001 Number of Leaks	0	
2001 Total Volume Released (bbl)	0	
2002 Number of Leaks	0	
2002 Total Volume Released (bbl)	0	
2003 Number of Leaks	0	
2003 Total Volume Released (bbl)	0	
12b. Internal Corrosion		
1990-1995 Number of Leaks	0	
1990-1995 Total Volume Released (bbl)	0	
1996-2000 Number of Leaks	3	
1996-2000 Total Volume Released (bbl)	42	
2001 Number of Leaks	0	
2001 Total Volume Released (bbl)	0	
2002 Number of Leaks	0	
2002 Total Volume Released (bbl)	0	
2003 Number of Leaks	0	
2003 Total Volume Released (bbl)	0	
12c. Natural Forces		
1990-1995 Number of Leaks	4	
1990-1995 Total Volume Released (bbl)	145	
1996-2000 Number of Leaks	3	

1996-2000 Total Volume Released (bbl)	2
2001 Number of Leaks	0
2001 Total Volume Released (bbl)	0
2002 Number of Leaks	0
2002 Total Volume Released (bbl)	0
2003 Number of Leaks	3
2003 Total Volume Released (bbl)	132
12d. Excavation Damage	
1990-1995 Number of Leaks	2
1990-1995 Total Volume Released (bbl)	7
1996-2000 Number of Leaks	2
1996-2000 Total Volume Released (bbl)	6650
2001 Number of Leaks	0
2001 Total Volume Released (bbl)	0
2002 Number of Leaks	0
2002 Total Volume Released (bbl)	0
2003 Number of Leaks	0
2003 Total Volume Released (bbl)	0
12e. Other Outside Force Damage	
1990-1995 Number of Leaks	1
1990-1995 Total Volume Released (bbl)	1
1996-2000 Number of Leaks	0
1996-2000 Total Volume Released (bbl)	0
2001 Number of Leaks	0
2001 Total Volume Released (bbl)	0
2002 Number of Leaks	0
2002 Total Volume Released (bbl)	0
2003 Number of Leaks	0
2003 Total Volume Released (bbl)	0
12f. Material/Weld Failures	
1990-1995 Number of Leaks	23
1990-1995 Total Volume Released (bbl)	40871
1996-2000 Number of Leaks	9
1996-2000 Total Volume Released (bbl)	5442
2001 Number of Leaks	2
2001 Total Volume Released (bbl)	50
2002 Number of Leaks	4
2002 Total Volume Released (bbl)	6014
2003 Number of Leaks	2
2003 Total Volume Released (bbl)	4625
12g. Equipment Failures	
1990-1995 Number of Leaks	19
1990-1995 Total Volume Released (bbl)	456
1996-2000 Number of Leaks	26
1996-2000 Total Volume Released (bbl)	7701.87
2001 Number of Leaks	2
2001 Total Volume Released (bbl)	25
2002 Number of Leaks	8
2002 Total Volume Released (bbl)	56.2
2003 Number of Leaks	1
2003 Total Volume Released (bbl)	0.12
12h. Incorrect Operations	
1990-1995 Number of Leaks	6
1990-1995 Total Volume Released (bbl)	115
1996-2000 Number of Leaks	4

1996-2000 Total Volume Released (bbl)	312
2001 Number of Leaks	1
2001 Total Volume Released (bbl)	1
2002 Number of Leaks	2
2002 Total Volume Released (bbl)	53
2003 Number of Leaks	0
2003 Total Volume Released (bbl)	0
12i. Other	
1990-1995 Number of Leaks	0
1990-1995 Total Volume Released (bbl)	0
1996-2000 Number of Leaks	0
1996-2000 Total Volume Released (bbl)	0
2001 Number of Leaks	0
2001 Total Volume Released (bbl)	0
2002 Number of Leaks	0
2002 Total Volume Released (bbl)	0
2003 Number of Leaks	0
2003 Total Volume Released (bbl)	0

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appropriate notification & rationale provided to the OPS

Enbridge Energy Integrity Management Inspection
Inspection Summary Report

Report Issue Date: July 7, 2003

Operator: Enbridge (US) Inc.

Corporate Address: 1100 Louisiana Street
Houston, TX 77002-5217

Operator ID Number(s): 11169 Enbridge (US)
31448 Enbridge Toledo

Dates of Inspection: May 12 - 16, 2003 (Week 1)
June 2 - 6, 2003 (Week 2)

Location of Inspection: Enbridge=s Superior Offices
119 N. 25th Street East
Superior, WI 54880-5247

Primary Contact: Jay Johnson, Compliance Coordinator
Phone: (715) 394-1512 Fax: (715) 394-1500

Persons In Attendance:

(Week 1):

Operator Representatives:

John Sobojinski (Enbridge (US))
Jay Johnson (Enbridge (US))
Patsy Bolk (Enbridge (US))
Walter Kresic (Enbridge Pipelines, Inc)
Brad Smith (Enbridge Pipelines, Inc)
Garry Sommer (Enbridge Pipelines, Inc)
David Weir (Enbridge Pipelines, Inc)
Gordon Jensen (Enbridge (US))
Gregg Harroom (Enbridge ND)
Brian Johnson (Enbridge ND)
Alina Mustonen (Natural Resources Engineering)
Brad Powers (Natural Resources Engineering)
Arthur Meyer (Enbridge Pipelines, Inc) by Teleconference
Greg Sevick (Enbridge Pipelines, Inc) by Teleconference
John Hayes (Enbridge Pipelines, Inc) by Teleconference

(Week 2):

Operator Representatives:

John Sobojinski (Enbridge (US))
Jay Johnson (Enbridge (US))
Patsy Bolk (Enbridge (US))
Walter Kresic (Enbridge Pipelines, Inc)
Brad Smith (Enbridge Pipelines, Inc)
Garry Sommer (Enbridge Pipelines, Inc)
David Weir (Enbridge Pipelines, Inc)
Gordon Jensen (Enbridge (US))
Dave McNeill (Enbridge (US))

Persons In Attendance:

(Week 1)

OPS Inspection Team:

David Barrett (OPS Midwest Region)
Joshua Johnson (OPS Midwest Region)
Byron Coy (OPS East Region)
Brian Pierzina (Minnesota Dept. of Public Safety)
Boyd Haugrose (Minnesota Dept. Of Public Safety)
Kevin Speicher (New York Dept. Of Public Safety)
David Kuhtenia (Cycla)
Anthony Tome (Cycla)

(Week 2)

OPS Inspection Team:

David Barrett (OPS Midwest Region)
Joshua Johnson (OPS Midwest Region)
Brian Pierzina (Minnesota Dept. of Public Safety)
Boyd Haugrose (Minnesota Dept of Public Safety)
Kevin Speicher (New York Dept. Of Public Safety)
David Kuhtenia (Cycla)
Anthony Tome (Cycla)

Inspection Objectives

The purpose of this inspection was to provide assurance that Enbridge (US) (ENB) has developed and implemented an Integrity Management Program as required by 49 CFR 195.452. Specifically, this inspection reviewed the operator=s processes for:

$ Identifying pipeline segments that could affect High Consequence Areas (HCAs);
$ Integrating information from all relevant sources to understand location-specific risks for these segments;
$ Developing and implementing a Baseline Assessment Plan;
$ Reviewing the results of integrity assessments;
$ Identifying and implementing remedial actions for anomalies and defects identified during integrity assessments;
$ Identifying and implementing additional preventive and mitigative measures to reduce risk on pipeline segments that can impact HCAs;
$ Performing on-going assessments of pipeline integrity; and
$ Evaluating Integrity Management Program performance.

This inspection also reviewed the implementation and results of ENB=s Integrity Management Program to date including a review of completed integrity assessments, and the repair and mitigation actions taken as a result of these assessments.
This inspection summary report is divided into two major sections. The first section summarizes the key features of the ENB approach for each of the Integrity Management Program Elements in 49 CFR 195.452 (f). The second section summarizes the issues and observations developed by the inspection team during the review of ENB=s program and its implementation.

Integrity Management Program Overview

Enbridge Energy, LP, formerly Lakehead Pipeline, spans approximately 3300 miles in the United States from the Canadian border near Neche, North Dakota to the Canadian border near Marysville, Michigan. Multiple lines run between Neche and Superior, Wisconsin. From there Line 5 runs north of Lake Michigan across the Straits of Mackinaw to Sarnia, Ontario. Lines also run south around Lake Michigan to Sarnia, Ontario. An extension also runs across the Niagara River into Buffalo, New York. The 3300 miles of Enbridge Energy pipeline also includes 36 miles of Enbridge Toledo Pipeline. Enbridge Energy reports a total of 700 miles of Acould affect@ HCA segments.

1. Segment Identification: The ENB segment identification process was documented in their HCA Management Plan (HMP). The process delineated the use of NPMS data for the segment identification process. Enbridge also considered the following features as HCAs:

$ The city of Rapid River, Michigan as an OPA using the corporate municipal boundary
$ 15 Navigable Water Crossings per 49CFR194

$ Municipal drinking water supplies in New York and additional supplies in Michigan

Pipeline locations were identified via a linear stationing system, with reference made in feet to local landmarks such as road and river crossings. As part of the HCA segment identification project, the stationing system was made electronic, tied to the U.S.G.S. coordinate system and imported as an ArcView shape file into ENB=s Geographic Information System. The stationing of pipeline segments which may potentially impact an HCA was identified by superimposing the pipeline shape file on top of 7.5 minute U.S.G.S. quadrangle maps and retrieving the relevant start/stop coordinates of the pipeline system.

HCA segments were identified using direct intersect and indirect impact methodologies. Indirect liquid release impact on an HCA was determined using overland, spray, and water transport mechanisms. Air dispersion calculations were used to determine the effect of the release of Natural Gas Liquids. Drinking water HCAs were determined to be impervious to the release of NGLs.

For overland liquid transport the spread distance was calculated based on a spread area determined from spill volume, topographical slope, and spread width. Spill volumes are calculated based on maximum capacity, location of remote controlled valves, elevation profiles, and time to recognize rupture. ENB assumed a maximum rupture isolation time of 8 minutes - 5 minutes for SCADA to recognize a rupture and 3 minutes for isolation. To determine the potential overland flow from a release at a tank, the largest tank at any given terminal was considered. The tanks were assumed to fail at their maximum operating level and the existence of berms or other spill mitigation features were ignored.

The overland spread is not calculated automatically; instead an analyst must determine the slope at each release location and calculate the spread using algorithms specifically developed for the shallow, moderate, and steep topography. The analyst then determines if any HCAs have been impacted by the release.

The water transport model described in the HMP used either hydraulic gradients or stream velocities to determine the transport distance given a 3 hour response time. However, on further discussion with the analyst, Acontrol points@ were also used to determine maximum water transport. Control points are locations along a waterway where interdiction can occur to stop the transport of crude oil. Based on accessibility, these points may be further downstream than the distance that would be calculated from hydraulic gradients. Again, the analyst did much of the calculation of water transport distances manually.

The NGL transport model used by ENB was RMP*COMP. This model was selected based on its ability to predict measured LEL levels during an NGL release in 1975. To simplify the analysis and provide a common basis for comparisons throughout the pipeline system, ENB determined the worst case scenario as the location specific release that resulted in the greatest travel distance to an endpoint i.e., the maximum distance between the release point and an endpoint. The endpoint is where the concentration of the vapor cloud is calculated to be less than 10% LEL.

With respect to performing segment identification prior to placing new lines into service, the inspection team noted that ENB was installing new pipeline from Gretna, ND to Clearbrook, MN as part of their ATerrace Phase III@ project. Portions of the new ATerrace III@ pipeline had been placed into service ahead of the originally anticipated in-service date without having completed segment identification as required by 195.452(b)(2). ENB provided the in-service dates of these Terrace lines and noted that segment identification was anticipated as being completed by the end of June, 2003.

2. Baseline Assessment Plan: ENB identified approximately 1500 HCA segments through their segment identification process. These 1500 HCA segments are rolled into 30 trap to trap testable pipeline segments. The Baseline Assessment Plan for these thirty segments was presented in the HMP. Based on the assessment schedule at the time of inspection, approximately 64% of the could affect HCA segment mileage will be assessed by September 30, 2004.

ENB determined the schedule for performing Baseline Assessments using Enbridge=s AFitness For Purpose@ (FFP) approach to pipeline management. ENB=s Fitness For Purpose approach was stated as being based on applying a series of programs and risk control measures over the lifecycle of the pipeline to manage defect growth.

The ENB Integrity Management Program employs a Adefect management@ approach that is largely built around information and knowledge collected from past ILI data. A defect tolerance level has been established based on restoring line pipe to its original pressure capacity, and defects that exceed ENB=s tolerance level are excavated and remediated. Defects not exceeding ENB=s tolerance levels are tracked and, where applicable, programs are set in place to monitor the defects. Assessment intervals are also calculated as part of the defect management approach, based on the non-remediated anomalies not growing past the ENB tolerance level prior to the next assessment.

As part of determining the schedule for performing baseline assessments on all 30 testable pipeline segments, ENB prepared a Line Description Document (LDD) for each segment. The LDD discussed corrosion growth rates, susceptibility to cracking, dents, and other information that could provide insight into the type of assessment that should be performed and the frequency with which it should be performed. For each of the 30 testable segments, ILI (geometry tool with metal loss tool) was the recommended method of assessment.

Enbridge explained the overall methodology for developing the BAP as a non-quantitative likelihood times consequence analysis. ALikelihood@ is not based on output of a risk model, but is taken as the assessment interval defined by the defect management approach. Consequence is considered based on the Consequence of Failure (COF) score for each of the 30 testable segments as calculated by a risk model.

ENB has developed a Risk Model using the Bass-Trigon Integrity Assessment Program (IAP). The risk model will be discussed in more detail in Section 5.0. The output of the risk model is used in two ways. First, the risk model calculates a risk for each of the 1500 plus could affect line segments. This is used by ENB to verify that high risk could affect HCA segments are assessed prior to September 30, 2004. Second, the risk model is used to calculate a COF for each of the 30 testable segments included in the BAP. If a testable segment is ranked within the top two thirds based on COF, its assessment frequency, as initially determined from the FFP analysis, is reduced by one year. As such, actual use of risk analysis values in determining the BAP schedule was limited to applying a one year reduction in the nominal FFP-calculated assessment interval in certain cases.

All 30 BAP testable segments were scheduled to be assessed by March 31, 2008.

The inspection team noted that the FFP approach to BAP development did not appear to directly include consideration of data that was not directly related to a defect. This included the 195.452(e)(1)-required AExisting or projected activities in the area@ factor (3rd party damage), use of Cathodic Protection data, and Anon-pipe= issues such as flange and fitting leaks.

3. Integrity Assessment Results Review: Training requirements for integrity assessment results personnel were delineated in a Training and Qualification manual. Training is provided through activities such as formal training courses, participation in conferences and workshops, presentation of papers at conferences, participation on standards committees, and participation in industry associations.

ENB relies upon ILI vendors to interpret assessment data. ENB then takes the data, reviews it for accuracy, determines if any anomalies meet the repair criteria, and forwards excavation (dig) sheets to field personnel. Standard in the vendor=s contract was the requirement to receive a preliminary data report within 30 days and a final report within 60 days.

Several recent assessments were reviewed by the inspection team and it appeared that the vendor=s final report was often not being received within 180 days of completion of the ILI run as required by the IMP rule. In addition, the date of discovery for repair conditions was when the final report for the MFL tool was accepted by ENB. Any anomalies identified by the geometry tool were not investigated until the final report for the MFL tool was received.

ENB provided unity plots of Aas reported@ versus Aas found@ conditions for anomalies. This information was used as part of their Fitness For Purpose process.

4. Remedial Action: The major requirements for remedial action pressure reductions, OPS notifications, etc., were covered by the HMP. One exception was that the HMP referenced use of

RSTRENG to determine the amount of pressure reduction to be taken for addressing immediate repair conditions. This is contrary to the requirements of 195.452(h)(4)(i), which requires the use of Section 451.7 of ASME/ANSI B31.4. Also, the timeliness of engineering evaluations to determine the pressure reduction for immediate repair anomalies that can not be addressed by the ASME/ANSI B31.4 formula was not specified in HMP.

During the review of assessment results, a pressure reduction on the 30 inch Bay City to Sarnia pipeline was not taken for approximately 30 days after discovery of an immediate repair condition. In another instance, a Line 4 Plummer to Clearbrook assessment was completed on May 30, 2002 and the final ILI report received on 11/1/02. Several anomalies were excluded on the basis that they had previously been remediated. In May, 2003, it was determined that these anomalies had not been previously remediated and needed to be repaired. The date of discovery for these anomalies was then set as May, 2003. The anomalies were 180 day repairs and were scheduled to be remediated by November, 2003. The inspection team noted that under the circumstances the anomalies should have been addressed promptly

5. Risk Analysis Process: ENB uses IAP to perform the risk assessment of line piping. The risk model calculates the Likelihood of Failure (LOF), the Consequence of Failure (COF), and the combined Failure Risk (LOF*COF). As noted previously, for the purpose of scheduling Baseline Assessments, only the COF was considered. For the purpose of identifying Preventive and Mitigative measures, and quantifying their impacts, both the LOF and COF were intended to be used.

Risk factor categories considered in LOF, and their respective weighting factors, were:

1) Corrosion (Internal and External) (31%)
2) Design/Material (33%)
3) System Operations (5%)
4) Ground Movement (3%)
5) Third Party Damage (28%)

Risk factor categories considered in COF, and their respective weighting factors, were:

1) Impact on Environment (30%)
2) Impact on Population (50%)
3) Impact on Business (20%)

Each of these risk factors had an extensive list of sub factors populated in the model, with a weighting score assigned to each sub factor.

The risk assessment model was also used to:

1) Identify the placement of EFRDs for minimization of spill volumes

2) Help prioritize digs
3) Prioritize projects

6. Preventive & Mitigative Measures: The IAP risk assessment model is also intended to be used to help identify and evaluate potential Preventive and Mitigative projects. The before and after results of the model can be used to evaluate the overall cost effectiveness of risk reduction projects. ENB anticipated that the risk assessment model will be fully utilized in the evaluation of P&M projects by 2004.

With respect to leak detection, ENB described the capabilities of existing and planned SCADA and CPM systems. At the time of inspection, CPM was installed on all of their US pipelines with the exception of Lines 6A and 6B. Line 6A was anticipated as having CPM operational in 2003 and Line 6B by 2004.

Regarding the evaluation of the need for additional EFRDs, the HMP contained a variety of technical detail regarding the criteria for placement of additional EFRDs, but the process for determining if/where additional EFRDs are necessary had not yet been well defined and implemented.

7. Continual Process of Evaluation and Assessment: As part of their Fitness For Purpose program, ENB had scheduled each of their 30 testable segments for a Baseline Assessment. In many cases the interval for reassessing each segment after the baseline was greater than 5 years. ENB anticipated that they will request a variance to the 5 year re-assessment interval for specific pipelines based on corrosion growth rate analysis, susceptibility to cracking, previous ILI testing history, age of pipe, etc. The inspection team noted the need for a thorough engineering analysis to be provided as part of any request for reassessment intervals beyond five years.

8. IM Program Performance Monitoring and Evaluation: Enbridge has adopted ten performance measures from API-1160, and stated that they will examine the need for implementation of future metrics as part of the continual improvement process. Current and past performance will be evaluated, trending analyses will be conducted, and the basic goals that performance metrics support will be subsequently analyzed to determine the need for modifications.

ENB had several other existing programs in place to measure its performance against industry standards, including:

Release database - By utilizing the release database ENB is able to determine the number of releases for each year by size and other variables.

API Pipeline Performance Tracking System (PPTS) - ENB has been a voluntary participant in the API PPTS since its inception. Use of this information was stated as enabling ENB personnel to assess the implications for operations and the impact of incidents as well as to prioritize risk mitigation strategies.

Pipeline Integrity Tracking System (PITS) - The ENB Pipeline Integrity Department has an existing database (PITS) that is being expanded to facilitate tracking of all investigative excavations and mitigation activities in the United States. This database can be queried to illustrate the number of excavations in a given year and their location. This output, when overlaid with the HCA data, allows ENB to determine the number of digs completed on a segment that could affect an HCA.

MAXIMO - ENB has a maintenance tracking database, MAXIMO, which can be used to track events that can affect the integrity of the pipeline.

An ENB steering committee is responsible for the continual monitoring of the HMP. The chairman of the steering committee is the Manager, U.S. Compliance and Risk Management. The steering committee is comprised of individuals from Pipeline Integrity, Safety & Environment, Operations Services, SCADA, Control Center Operations, Engineering, Operations and Compliance and Risk Management. The steering committee meets via teleconference whenever issues arise that warrant the attention and discussion of the committee.

OPS Feedback

<u>Enbridge Inspection Feedback</u>

Segment Identification

1. Given that segment identification is performed manually using 7.5 minute U.S.G.S. maps it is difficult to validate the methodology. Some issues are:

$ Overland buffer zones were not presented graphically as the composite final buffer zones.
$ Water transport was dependent on stream velocities, which was dependent on hydraulic gradients. It was not clear where water transport was terminated.
$ For some waterways control points were used to determine the extent of transport. The actual locations of these control points, however, was not documented and apparently only known to the analyst performing the could affect analysis.

2. HMP does not provide the basis for the adequacy of the assumed five minute operator response time for lines that do not have CPM (i.e., five minute backs-up CPM indication, so application of the Aten minute rule@ for lines that do not have CPM may be appropriate).

3. ENB used regression analysis to predict overland spread versus release volume for the three topographical slopes. Not all release data was used to perform the curve fits. For example, the release data for the Cohasset, MN leak was not used.

4. Discrepancies were noted between the could affect segments identified on the HCA maps and those listed in HMP Table 2. The tables are used to determine if an anomaly is within an HCA segment. If the tables are not current, a n anomaly could be treated outside of the IMP rule repair criteria.

5. Enbridge needs to substantiate the assumptions used in the water transport model. These include:

- Validating the three hour response time for stream flow transport termination (e.g., comparison with the 7/4/02 Cohasset response time).
- Validating that the 2x mean stream flow velocity is appropriate.

6. Lack of accounting for multiple instances (overlap) of common types of HCAs when segment identification results are input into the consequence analysis. For example, if several drinking water supplies are potentially affected by a particular testable section of line, the occasion of multiple drinking water supplies being affected is important in addition to the fact that drinking water needs to be included in the types of HCAs affected by that section.

7. Since the segment identification process is visually/manually performed by an analyst, detailed process documentation should be developed. Examples include:

- Description of the process of connecting tangential buffer zones into a composite buffer zone not included in HMP.

- Description of use of control points for the termination of water transport not included in the HMP.

8. Requirements for record retention times, locations, and responsibility not clearly specified in the HMP.

9. HCA segment identification was not performed prior to putting the new 36" Category 3 lines into service. [Enbridge stated the input data for IAP volume release calculations would be completed by the end of June, 2003, and that segment ID completed thereafter. Inspection team noted OPS requirement to have segment ID completed prior to placing new lines into service - 195.452(b)(2).]

Risk Analysis

1. Historical operating data is not being used in the Risk Assessment Model to the fullest extent. E.g., near misses and unscheduled shutdowns.

2. Decisions regarding preventive and mitigative actions for external and internal corrosion are being made outside of the risk model.
3. A quality check of the data in the risk model should be performed. For example, the variable score for the pipeline segment at the Mississippi River crossing in the Cass Lake to Deer River pipeline was not populated and the ICF variable had not been changed for pipelines where an ILI ran had been completed.

4. Impact on Business (Customer Service Disruption) was a major contributor to Consequence of Failure in both of the mainline sections reviewed. Given the weighting of this risk factor, it appears this may be true for all mainline testable sections.

5. Risk assessments of facilities do not include operator error.

6. Flange and fitting leaks is the number one problem at facilities, Enbridge is trending flange and fitting leaks using MAXIMO but does not appear to be including this information in the current evaluation of risks.

7. The qualification requirements for risk analysis personnel are not well documented in the HMP.

8. The Risk Assessment team must solicit input regarding updated system configurations and operating practices from field organizations rather than having the field input information based on trigger points that are defined by the HMP.

Baseline Assessment Plan

1. A crack susceptibility study is ongoing; however, it should have been completed and the conclusions factored into the development of the BAP.

2. Lack of consideration of 195.452(e)(1) required factor (vi) AExisting or projected activities in the area@ (third party damage) in the process for establishing the baseline assessment schedule. It appears that third party damage is not taken into consideration when prioritizing the Baseline Assessment schedule.

3. The HMP does not include the requirements for incorporating new HCA could affect segments into the BAP within 1 year and performing a Baseline Assessment within 5 years (' 195.452(d)(3)(ii)).

Integrity Assessment Results Review

1. In general, the IM plan is the place to bring all elements of the ENB integrity management program together. Areas of possible improvement include the following:

$ As the primary IM document, the HMP does not incorporate by reference all associated IM documents. For example, the Qualifications & Training Guideline Document was described as part of the ENB integrity management processes, but was not referenced in the HMP.

$ Integration of information/risk analysis (195.452(g)) results does not appear to have a central role in the overall evaluation of integrity challenges. For example, 3rd party damage potential is left to the discretion of regional operations to determine if additional geometry assessments need to be conducted, CP data is not well integrated with ILI results, and Anon-pipe@ issues such as flange leakage events are treated outside of the risk analysis process.

2. The ENB approach to assessment tool tolerances (e.g., use of unity plots, etc.) could be clarified in the HMP.

Remedial Action

1. HMP references use of RSTRENG to determine the amount of pressure reduction to be taken for addressing immediate repair conditions. This is contrary to the requirements of 195.452(h)(4)(I), which requires the use of Section 451.7 of ASME/ANSI B31.4.

2. Timeliness of engineering evaluations to determine the pressure reduction for immediate repair anomalies that can not be addressed by the ASME/ANSI B31.4 formula is not specified in HMP.

3. Line 4 Plummer to Clearbrook assessment was completed on May 30, 2002; the final ILI report was received on 11/1/02. Several anomalies that were identified were excluded on the basis that they had previously been remediated. In May, 2003, it was determined that this was not the case and the date of discovery for those anomalies was revised to be May, 2003. The anomalies were categorized as 180 day repairs and are scheduled to be remediated by November, 2003. This highlights the following issues:

$ There may be a weakness that needs to be corrected in ENB=s process to identify previously remediated locations.

$ The rule requires that discovery be within 180 days of completion of a tool run. The proper response to the error may be to schedule the anomalies for immediate remediation.

4. Discovery was greater than 180 days in several cases due to delayed ILI vendor reporting. Examples included Line 5 Bay City to Sarnia, Line 3 Gretna to Clearbrook, Line 2 Gretna to Clearbrook.

5. Review of assessment results indicated that anomaly results spreadsheets did not identify geometry tool results.

6. For the baseline assessment of Line 10 (Grand Island-E. Niagara, E. Niagara-Kiantone), ENB appears to have missed identification of one HPA HCA (~ 80,000 ft. in Buffalo) when evaluating assessment anomalies. Pressure reduction taken upstream, but no evaluation if pressure reduction was sufficient for the Buffalo section. [Note: Posting of Acould affect@ data to ENB intranet may facilitate improved accuracy of locating anomalies within HCAs.]

Continual Process of Evaluation and Assessment

1. HMP does not explicitly address the Aunavailable technology@ 180 day notification. Inclusion of this aspect may be an enhancement to the HMP, given that this is also applicable to instances of tool unavailability as well as basic technology being unavailable.

US Department of Transportation
Research and Special Projects Administration
Office of Pipeline Safety

Integrity Management Program
49 CFR 195.452

Integrity Management
Inspection Protocols

January 2003

Table of Contents

Explanation of Inspection Form Format

The next two pages provide a brief description of each item in the Integrity Management Inspection Form.

Protocol #	*Keywords reflecting the subject area of the Protocol Question are entered here. Each question has a unique number, as indicated to the left.*
Protocol Question	*Question to be answered in reviewing an operator's Integrity Management Program or the implementation of its Program.* *Some questions in the Integrity Management Inspection Protocols have two parts. One part deals with the inspection of a particular aspect or feature of the operator's Integrity Management processes, procedures, technical methods, etc. The second part addresses how effectively the operator has implemented that process and the results that have been obtained.*

This section contains additional guidance and items for consideration by the inspector in reviewing operator response to the protocol question. This guidance presents characteristics typically expected in an effective Integrity Management Program consistent with the intent of the Rule. Some, all, or none of these characteristics may be appropriate depending on factors unique to each protocol, and the operator's Integrity Management Program and its pipeline assets. Operators should be able to demonstrate that their programs address each of these characteristics or should be able to describe how their program will be effective in their absence.

For some protocol questions, this portion of the inspection form is also used to articulate specific prescriptive requirements in the Rule. These requirements are mandatory for all Integrity Management Programs.

Rule Requirement	*Reference to related rule requirement(s).*

Inspection Summary	Process	*This space is provided to record any issues or concerns the inspector identifies in reviewing the operator's response to the protocol question. As noted above, some questions in the Integrity Management Inspection Protocols have two parts: a "process" review, and a review of the operator's "implementation" of that process. To deal with these different perspectives, this part of the inspection form has been subdivided into "Process" and " Implementation" portions.*
	Implementation	

Inspection Results *The boxes to the right are checked based on the information supplied in the Summary.*		**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed: *Documents reviewed in answering the Protocol Question are listed below.*

Document Number	Rev.	Date	Document Title

Inspection Notes:

This section is provided to record more detailed information about the operator's program obtained during the review of the operator's response to the protocol question. For protocol questions dealing with the implementation of a particular facet of an operator program, a summary of the records review is entered at this location.

Integrity Management

Inspection Form

Name of Operator: Enbridge (US)

Headquarters Address:
119 N. 25th Street East
Superior, WI 54880-5247

Company Official: John Sobojinski, Manager, U.S. Compliance and Risk Management

Phone Number: 715-394-1505

Fax Number: 715-394-1500

Operator ID:

11169 (Enbridge)

31448 (Toledo)

Activity ID:

Persons Interviewed	Title	Phone No.	E-Mail
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OPS Representatives:

David Barrett, OPS Central Region, Weeks 1 and 2
Joshua Johnson OPS Central Region, Weeks 1 and 2
Byron Coy, OPS Eastern Region, Week 1
Brian Pierzina, Minnesota Dept. of Public Safety, Weeks 1 and 2
Boyd Haugrose, Minnesota Dept. of Public Safety, Weeks 1 and 2
Dave Kuhtenia, Cycla, Weeks 1 and 2
Anthony Tome, Cycla, Weeks 1 and 2

Dates:

5/12/03–5/16/03 (Week 1)
6/2/03-6/6/03 (Week 2)

System Descriptions:

Enbridge Energy, formerly Lakehead Pipeline, is comprised of 3,308 ,miles of pipeline. Enbridge Energy pipeline runs from the Canadian border, near Neches, ND, to Superior, WI. From Superior, the pipeline takes a northern route around Lake Michigan to Sarnia, Ontario, and a southern route around Lake Michigan to Sarnia. From west of Lake Ontario, a line runs east across the US/Canadian border into Buffalo, NY. This line is part of Enbridge Energy. The system is also comprised of 36 miles of pipeline under Enbridge Toledo for a total of 3344 miles of pipeline. Of this, 701 miles of pipeline are HCA could affect miles.

Integrity Management
Inspection Protocol 1

Identification of Pipeline Segments That Could Affect High Consequence Areas

Scope:
This Protocol addresses the identification of pipeline segments that could affect one or more HCAs. This Protocol addresses all of the steps to perform the segment identification, including identification of HCAs, correlation of HCAs to pipeline locations, commodity transport to HCAs from spills located outside of HCA boundaries, buffer zones, and justification for excluding segments physically located within a HCA. This Protocol does not address how the segment identification results are further used in other Integrity Management (IM) Program elements.

Protocol #1.01	Segment Identification: HCA Identification
Protocol Question	Does the process to identify segments that could affect HCAs include steps to identify, document, and maintain up-to-date geographic locations and boundaries of HCAs using the NPMS and other information sources as necessary? ——— Verify that the operator correctly identifies and maintains up-to-date locations and boundaries of HCAs using NPMS and other information sources as appropriate for all states/regions in which it operates.

An operator's process to identify pipeline segments that could affect HCAs must identify the location of HCAs that could be affected by pipeline failures. To accomplish this step, the operator's documented IM process would be expected to include the following elements:

1. The use of NPMS (or equivalent sources) to identify HCAs.
2. Adequate measures to identify drinking water USAs in New York state and ecological USAs in Pennsylvania (these are the only states for which NPMS has no drinking water or ecological USA data).
3. Adequate provisions to assure that local knowledge, information obtained from routine field activities (e.g., ROW surveillance, aerial surveys), and other information sources are used as required to supplement NPMS data in order to accurately reflect current conditions in the vicinity of the pipeline.
4. Provisions for periodic review and update of HCA boundaries, including timely use of revised NPMS data and local information in the update (e.g., per the requirements of 452 (d)(3)).

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline — Date Category 1 — March 31, 2002. Category 2 — February 18, 2003. Category 3 — 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 — December 31, 2001 Category 2 — November 18, 2002. Category 3 — Date the pipeline begins operation.
	§195.452 (d)(3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified.

Inspection Summary	Process	
	Implementation	The buffer zones presented on the HCA maps did not always represent the buffer zone applicable to that line segment, it would be very difficult for field reviews to verify the validity of the final buffer zones.

Protocol 1.01 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.01 Inspection Notes:

Enbridge used NPMS to identify HCAs that were either directly intersected by pipelines or that could be indirectly affected via overland or water transport of crude, spray of crude, or the air dispersion of NGL. Enbridge also considered the following features as HCAs:

1)The city of Rapid City, Michigan as an OPA using the corporate municipal boundaries.
2)15 Navigable waterways identified by 49CFR194
3)Municipal drinking water supplies in New York and Michigan

The components considered to potentially present a risk to an HCA were:

1)Mainline Piping
2)Pumping Stations
3)Above Ground Storage Tanks at Terminals
4)Breakout Storage Tanks at Terminals

The liquids considered were crude, condensate, and natural gas liquids (NGL).

Per the HCA Management Plan – "The HCA identification review ensures that as relevant data becomes available appropriate modifications are made to Pipeline Segments in HCAs. The review will occur once each year…"

Protocol # 1.02	Segment Identification: Direct Intersection Method
Protocol Question	Does the operator have an adequate process to determine all locations where its pipeline system is located in a HCA? ——— Verify that the operator determined all locations where its pipeline system is located in a HCA (i.e., determine if the operator correlated its complete pipeline system(s) maps with the HCA maps, and identified areas where the pipeline system intersects a HCA).

The purpose of this question is to review the operator's identification of intersections between the operator's pipeline and HCAs. An effective operator process for identification of these intersections would be expected to have the following characteristics:

1. The process requires that segments that are physically located within HCAs are identified and defined by specific locations that represent the place where the pipeline actually intersects that HCA boundary. (The entire segment that could affect the HCA could be much larger based on transport analysis.)
2. The process requires that pipeline facilities that are located in HCAs are identified (not just line pipe).
3. Any GIS or other mapping software used by operators employs a valid analysis algorithm or methodology to identify segments that intersect HCAs.
4. Any manual analysis techniques used by operators employ a valid analysis technique or methodology to identify segments that intersect HCAs.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline — Date Category 1 — March 31, 2002. Category 2 — February 18, 2003. Category 3 — 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline — Date Category 1 — December 31, 2001 Category 2 — November 18, 2002. Category 3 — Date the pipeline begins operation.
	§452 (a) *What pipelines are covered by this section?* The section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

Inspection Summary	Process	
	Implementation	

Protocol 1.02 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.02 Inspection Notes:

As part of the HCA segment identification project, the stationing system was tied to the U.S.G.S. coordinate system and imported as an ArcView shape file in ENB's GIS. The stationing of pipeline segments which may potentially impact an HCA was identified bysuperimposing the pipeline shape file on top of 7.5 minute U.S.G.S. quadrangle maps and retrieving the relevant start/stop coordinates of the pipeline segments.

The identification process for direct impact pipeline areas consisted of identifying system components that are physically located within or tangent to an HCA. The segments of pipe directly impacting HCAs were identified visually by comparing system alignment with the HCA locations provided by NPMS and those identified by ENB.

The components considered during the identification of could affect HCA segments included pumping stations, Above Ground Storage Tanks and Breakout Tanks in Terminals.

ENB identified 25 Pumping Stations that could affect an HCA through either direct intersection of indirect impact. Currently, the spill volume used to determine indirect impact is based on mainline piping that runs through the station. In late 2003 ENB willl be initiating a project to develop and implement a risk assessment model specifically for stations. This will include a volume out calculation based on station piping. It is anticipated that this project will be completed in late 2004 to early 2005.

An IMP for station piping has been implemented in accordance with the "Integrity Management of Station Piping Guidance Document". This document provides assessment procedures to identify, prioritize, and mitigate corrosion and integrity issues associated with stations.

For tanks, the release volume was based on the largest tank in a terminal assuming the tank if filled to its maximum operating level, and there are no berms to mitigate the release.

Segment identification is performed manually for both direct intersect and indirect impact (via transport of crude, condensate, or NGL).

Protocol # 1.03	Segment Identification: Direct Intersection Exceptions
Protocol Question	Does the operator's segment identification process require development and documentation of an adequate and convincing technical justification for concluding that segments located in a HCA could not affect the HCA in the event of a release? ——————— Determine if the operator identified any segments located in a HCA that could not affect that HCA in the event of a failure. If so, verify that the operator provided an adequate and convincing technical justification for that contention consistent with its documented process.

452 (a) presumes that a pipeline segment within a HCA could affect that HCA. If the operator concludes that some segments within HCAs could not affect the HCAs, then a technical justification for this conclusion is required. If the operator intends to maintain any segment intersecting a HCA could not affect that HCA, then an effective operator process would be expected to include provisions for such a technical justification with the following characteristics:

1. Guidance for performing an analysis to substantiate the conclusion that a pipeline segment located within a HCA could not affect the HCA.
2. An adequate level of rigor specified for any analysis that is used to justify the conclusion that a segment located in a HCA could not affect the HCA.
3. A valid analysis to justify the conclusion that a pipeline segment located within a HCA could not affect the HCA.

The operator's justification that a segment intersecting a HCA could not affect the HCA may be based on different factors. These factors include:

1. Minimal impact. (This justification is based on analysis that shows that the commodity does reach and impact the HCA, but that the impact is insignificant and small enough to justify the assertion that the release could not adversely affect the HCA).
2. HVL properties.
3. Topographical considerations.
4. HCA properties.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.

	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.
	§452 (a) *What pipelines are covered by this section?* The section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

Inspection Summary	Process	
	Implementation	

Protocol 1.03 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.03 Inspection Notes:

NGL releases were assumed to not impact drinking water HCAs.

Protocol # 1.04	Segment Identification: Release Locations Selected for Analysis
Protocol Question	Does the operator's segment identification analysis process include a technically adequate method to determine the locations/scenarios of potential commodity releases? ——————— Verify that the operator's identified release locations are appropriate, technically adequate, and consistent with its documented process.

The operator's approach for analyzing the potential effects of pipeline failures that could affect HCAs must define potential locations on the pipeline where releases could occur. An effective operator program would be expected to consider the following elements:

1. Proximity to water crossings;
2. Variations in topography near the line;
3. Variations in distance between the pipeline and the HCA (for HCAs that do not intersect the pipeline);
4. Adequate choice of release locations, if fixed spacing along the pipeline is used in the definition of locations;
5. Consideration of spills involving pipeline facilities (e.g, breakout tanks).

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.

Inspection Summary	Process	
	Implementation	

Protocol 1.04 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.04 Inspection Notes:

ENB uses the worst case scenario – full mainline rupture with 100% volume out – for calculating the potential spill volume. The maximum release volume is based on:

1) Maximum capacity/throughput
2) Location of remote operated valves
3) Elevation profile
4) Pipe outer diameter and wall thickness
5) Time to recognize the rupture
6) Initial loss and stabilization loss

The potential rupture volume is calculated for each change in elevation, pipe outer diameter, or wall thickness.

For tanks, ENB used the volume of the largest tank at a terminal, assumed it was filled to its maximum operating level, and that there were no berms or features to mitigate the release.

Protocol # 1.05	**Segment Identification: Spill Volume**
Protocol Question	Does the operator's process include a technically adequate method to determine the volume of commodity that could be released from a leak or rupture, if needed for the operator's analysis to identify segments that could affect HCAs? ——————— Verify that the release volume estimates are adequate and consistent with the operator's documented process.

Analyzing the potential effects of pipeline failures that could affect HCAs involves estimating the volume of commodity that could be released in the event of a failure. An effective operator program would be expected to include appropriate treatment of the following factors that affect estimation of spill volume:

1. Failure hole size;
2. Operating conditions (e.g., flow rate, operating pressure);
3. Leak detection and response time;
4. Calculations of drain down following leak or rupture;
5. Release rate estimates, if air dispersion of vapor clouds is a transport mechanism that is applicable to the operator's system; and
6. Pipeline system design factors (e.g., pipe diameter, distance between isolation valves, location of tanks and other facilities).

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to include appropriate treatment of the above factors.

Note: Because an adequate spill volume analysis may require consideration of various scenarios and combinations of assumptions regarding different variables, the operator's release estimate analysis would be expected to include a sensitivity analysis to variations in assumptions, including consideration of both catastrophic failure and leaks below detection limits.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>ENB does not address the basis for line ruptures being bounding versus small, less detectable leaks.

ENB does not provide the basis for the adequacy of the 5 minute operator response time to take action to isolate a leak.

The calculated release volume for the Cohasset leak was less than what was actually reported.</td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 1.05 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.05 Inspection Notes:

For mainline piping ENB assumed a full guillotine rupture and looked at release volumes at changes in pipe diameter and wall thickness (release flow area) and changes in elevation. For tanks, the largest tank in a terminal, assumed to be operating at it s maximum operating level with no mitigative features (berms, etc.) in place.

The release volume in mainline piping is dependent on response time. The assumed response time for isolating a rupture with an EFRD in place is 5 minutes for SCADA recognition and 3 minutes for operator response.

Protocol # 1.06	Segment Identification: Overland Spread of Liquid Pool
Protocol Question	Does the operator's process include an adequate analysis of overland flow of liquids to determine the extent of commodity spread and its effects on HCAs? ——— Verify that the operator produced an overland spread analysis (if applicable) that is technically adequate and consistent with its program requirements.

Analyzing the potential effects of pipeline failures that could affect HCAs involves estimating the distance and direction of the commodity spilled from a potential failure at a location on the pipeline and determining if the identified direction and extent of the spill could result in adverse consequences to a HCA. Commodity spilled from hazardous liquid pipelines may spread by land, water, or air to impact HCAs. This protocol considers the operator's analysis of overland spill transport. An effective operator process would be expected to include the following characteristics in analyzing overland spread of spills:

1. The assumptions used in the overland spread analysis are valid for all applications of the assumption (e.g., assumptions used to conduct overland spread analysis used as a basis for buffer zone size should be valid for all systems and locations to which the buffer zone is applied).
2. The overland spread analysis technique adequately and accurately evaluates the effects of topography on overland spread consequences.
3. Assumptions on operator spill response actions used to determine the pool spread limits are valid.
4. The overland spread analysis process identifies and adequately analyzes local factors such as ditches, sewers, farm tile, drains, etc.
5. Any computer modeling of overland transport mechanisms that is used produces valid overland spread consequence results.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the overland spread distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.

Inspection Summary	Process	
	Implementation	In the Manistique area a could affect segment appear on the HCA map but was not listed in the HMP. The HMP is used to determine if an anomaly lies within a could affect segment.

Protocol 1.06 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.06 Inspection Notes:

Per the HCA Management Manual, "Overland flow Is assumed to be instantaneous, to follow topographic relief, to be influenced by drains and flow barriers, and has a tear shaped geometry. The overland flow is detention dominant with an average thickness of 1 inch." The area of the pedal is based on the volume of crude, or condensate, released and a factor that simulates slope.

There are three possible slopes shallow, moderate, and steep. The slope factor was estimated using actual release data. The releases were binned into one of the three groups depending upon the topography at the release site. A curve fitting process was then used to determine the slope factor. One release – Cohasset – was not included in the data used to calculate the slope factors and the calculated release volume was less than the actual.

Protocol # 1.07	Segment Identification: Water Transport Analysis
Protocol Question	Does the operator's process include a technically adequate analysis of water transport of liquids to determine the extent of commodity spread and its effects on HCAs? ——— Verify that the operator produced a water transport analysis (if applicable) that is technically adequate and consistent with its program requirements.

This protocol considers the operator's analysis of spill transport through waterways. An effective operator process would be expected to include the following characteristics in analyzing the transport of spills by water:

1. The analysis adequately evaluates the effects of all applicable factors, including stream conditions, flow characteristics, and water properties on water transport consequences.
2. The assumptions used in the analysis are valid for all systems and locations to which the assumptions are applied (e.g., assumptions used to conduct water transport analysis as a basis for buffer zone size are valid for all systems and locations to which the buffer zone is applied).
3. Pool spread limits based on assumptions of operator spill response actions are defensible.

Additional factors that may be important to understanding water transport of spilled commodity include:

1. Changes in commodity properties due to interaction with the environment (such as dissolved MTBE transport and change in buoyancy and density due to evaporation).
2. Commodity solubility.
3. Abnormal stream conditions such as flood or storm conditions, etc.
4. Subsurface water transport as well as surface water transport.
5. Indirect introduction into water due to overland pool spread that reaches waterways.
6. Introduction into water from spray releases.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the spill water transport distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.

Inspection Summary	Process	ENB must justify use of a three hour transport termination time for water transport. ENB must justify the use of a stream velocity that is 2 times the mean velocity.
	Implementation	

Protocol 1.07 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.07 Inspection Notes:

Using a 3 hour response time, the water transport distance is calculated using twice the U.S.G.S. flow velocity where actual flow data is available. Where stream flow data is not available, ENB classified streams and rivers into three categories – high, medium, and low energy streams. Using the three hour response time and a calculated mean velocity using the Chezy-Manning equation, the transport distance for each of the of the three stream types is 0.9 miles for low energy, 4.4 miles for medium energy, and 11.9 miles for high energy.

ENB also stated that control points were used on some streams to determine the maximum transport distance. Control points are where the spread of crude can be arrested through the placement of booms.

From the manual method of determining indirect impact of water transport, it was not always clear what assumptions were being used by the analyst.

Protocol # 1.08	Segment Identification: Air Dispersion Analysis
Protocol Question	Does the operator's documented consequence analysis process include a technically adequate analysis of the air dispersion of vapors from the release of highly volatile liquids and volatile liquids to determine the extent of harmful commodity vapor spread and its effects on HCAs? ——————————— Verify that the operator produced an analysis of the air dispersion of vapors (if applicable) that is technically adequate and consistent with its program requirements.

This protocol considers the operator's analysis of spill transport through air dispersion. An effective operator process would be expected to have the following characteristics in analyzing the dispersion of spills through air:

1. The process includes air dispersion analysis where appropriate for the operator's system and release scenarios.
2. The operator's selection of analysis model and software tool is appropriate for the operator's system and release scenario.
3. The analysis correctly models the physical properties of the commodity that could be released.
4. The air dispersion analysis inputs and assumptions used to determine if the release could affect a HCA are adequate.
5. If the air dispersion analysis involves consideration of threshold levels of concern for the adverse effects of releases, then the thresholds that are used are based on valid criteria to determine if releases could affect a HCA.
6. For completeness, the air dispersion analysis considers the potential for secondary effects, (e.g., chemical byproducts of combustion) to adversely affect a HCA.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the vapor dispersion distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.

Inspection Summary	Process	
	Implementation	

Protocol 1.08 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.08 Inspection Notes:

Air dispersion of NGL was calculated using RMP*COMP. This model was chosen because it was able to predict the one release where ENB had empirical data. The spread of NGL from the release point is terminated when the concentration of NGL at the spread boundary is equal to 10% of LEL. It was assumed that NGL had no impact on drinking water HCAs

Protocol # 1.09	**Segment Identification: Identification of Segments that Could Affect HCAs**
Protocol Question	Does the operator's analysis process adequately identify all locations of segments that do not intersect, but could affect, HCAs? ――――――――――――― Review the operator's analysis and determine if there is reasonable assurance that the operator correctly identified all specific locations that define segments that could affect a HCA.

This protocol addresses the results of the operator's process for segments that do not intersect, but could affect, HCAs. An effective operator process would be expected to have the following characteristics:

1. The process requires that segments that could affect HCAs (according to the analysis reviewed under protocols 1.04 through 1.08) are identified and defined by specific locations.
2. If the operator used a buffer zone approach to identify segments that could affect HCAs, then the approach identifies all segments that are within the buffer distance of any HCA.
3. If the operator identified any segments based on buffer zone intersection that were declared not to affect the HCA, then the technical justification for this assertion is adequate.
4. The operator's analysis adequately identifies pipeline facilities that could affect HCAs.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 March 31, 2002. Category 2 February 18, 2003. Category 3 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline Date Category 1 December 31, 2001 Category 2 November 18, 2002. Category 3 Date the pipeline begins operation.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>Lack of accounting for multiple instances of common types of HCAs in the consequence analysis.</td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 1.09 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.09 Inspection Notes:

The manual method used to determine indirect impact on HCAs made it difficult to verify that the process accurately captured could affect HCA segments. The process seemed to be undergoing fine tuning within ENB. Between the HCA Management Manual dated April 28, 2003 and the one dated May 28, 2003 an additional 87 miles of could affect HCA segments form pipeline outside of HCAs was identified.

Protocol # 1.10	Segment Identification: Revision Control
Protocol Question	Does the operator's segment identification process include the control of revisions subsequent to the initial determination, and if so, does the process require that changes be adequately justified, documented, and incorporated into the baseline assessment plan and other program elements? ――――――――――― Determine if the operator's segment identification results have been revised since the initial determination, and if so, verify that changes have been adequately justified, documented, and incorporated into the baseline assessment plan and other program elements.

The operator's initial segment identification may require revisions. This protocol examines the operator's steps for controlling revisions. An effective operator program would be expected to have the following characteristics:

1. Adequate controls for developing and implementing revisions to the segment identification analysis.
2. Interfaces with other IM Program elements to assure the revised segment identification results are reflected in the other elements (e.g., baseline assessment plan).
3. Provisions to identify and analyze changes to the pipeline, such as design and operations, for impacts on segment identification and other IM Program elements.
4. Provisions to identify and analyze changes to the local terrain or environment near the pipeline, both from operator activities and from third party activities, to determine the impact on segment identification and other IM Program elements.
5. The operator's process does *not* allow revisions to segment identification analysis after the start of integrity assessments in order to avoid remediation of assessment anomalies.
6. If the operator utilizes the segment identification results in other business processes, then the operator's segment identification process includes interfaces with other operator business program elements, such as emergency plans, to assure proper application of the results.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.
	§195.452 (d)(3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified.
	§452 (l) *What records must be kept?* (1) An operator must maintain for review during an inspection: (i) A written integrity management program in accordance with paragraph (b) of this section. (ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section. (2) See Appendix C of this part for examples of records an operator would be required to keep.

Inspection Summary	**Process**	
	Implementation	

Protocol 1.10 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.10 Inspection Notes:

The process of control of segment identification was to archive a set of HCA maps after each iteration. It is difficult to easily discern the rationale for the extension, deletion, or addition of a could affect segment.

HCA review will be performed annually per the HCA Management Plan.

Protocol # 1.11	Segment Identification: Process Formality
Protocol Question	Is the operator's process for identifying pipeline segments that could affect HCAs documented with sufficient specificity and detail to provide assurance that it can be implemented in a consistent manner? Are the analytical techniques and assumptions used to identify pipeline segments that could affect HCAs adequately justified and documented in the operator's IM Program? ——————————— Verify that the operator's process implementation, documentation, records, management practices, and applied resources provide reasonable confidence that the segment identification process has been (and will be) consistently and appropriately implemented.

An effective operator program would be expected to have the following characteristics:

1. The process includes documented guidance or procedures describing the steps required to identify segments that could affect HCAs. The instructions are sufficiently detailed so that different qualified persons would likely be able to independently implement the process and reach similar results.
2. The process to identify and document HCA boundaries and pipeline location data is adequate.
3. The IM Program requires that idle lines be included in the segment identification process.
4. All technical bases and segment identification analysis assumptions are identified and documented.
5. The process includes provisions to document each segment that could affect HCAs by specific identifiable endpoints.
6. The guidance specifies records to be generated in the process of implementing segment identification and specifies the records retention period that complies with IM rule requirements.
7. The guidance specifies distribution, by organizational group or title, for the records/results of segment identification.
8. The process has documented internal review or quality assurance mechanisms in place to assure accurate, complete, appropriate, and consistent results. These mechanisms address both completeness and quality of results, management approval of results, and validation of software applied in segment identification.
9. The process documentation identifies the characteristics of the HCAs that could be affected by specific segments (e.g., the ecological concerns that define a USA).

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area.

	§452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: Pipeline — Date Category 1 — March 31, 2002. Category 2 — February 18, 2003. Category 3 — 1 year after the date the pipeline begins operation. (2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column: Pipeline — Date Category 1 — December 31, 2001 Category 2 — November 18, 2002. Category 3 — Date the pipeline begins operation.
	§452 (l) *What records must be kept?* (1) An operator must maintain for review during an inspection: (i) A written integrity management program in accordance with paragraph (b) of this section. (ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section. (2) See Appendix C of this part for examples of records an operator would be required to keep.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>Description of the process for connecting tangential buffer zones into a composite buffer zone is not included in the HMP.
Description of the use of control points for th termination of water transport is not included in the HMP.
Records retention requirements not included in the HMP.</td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 1.11 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.11 Inspection Notes:

Many of the assumptions used by analyst in the segment identification process are documented on the HCA maps. Even then, it is not always clear which of multiple possible assumptions has been selected. For example, overland transport could result in one of three buffer zones being selected dependent on topography. The HCA maps showed one buffer zone (shallow) for graphical depiction whereas the analyst could have chosen either moderate or steep based on measuring the slope at the point of release.

Protocol # 1.12	**Segment Identification: Timely Completion of Segment Identification**
Protocol Question	Did the operator complete segment identification by the dates prescribed in 452(b)(2)?

The operator must identify all segments that could affect HCAs by the prescribed dates:

1. 12/31/2001 for Category 1 pipelines
2. 11/18/2002 for Category 2 pipelines
3. Beginning of operation for Category 3 pipelines

<table>
<tr><td>Rule Requirement</td><td colspan="2">§452 (b) What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:
(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

Pipeline — Date
Category 1 — December 31, 2001
Category 2 — November 18, 2002.
Category 3 — Date the pipeline begins operation.</td></tr>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td></td></tr>
<tr><td>Implementation</td><td>ENB placed a portion of their new Terrace III pipeline into service without having performed segment identification.</td></tr>
</table>

<table>
<tr><td rowspan="3">Protocol 1.12
Inspection Results</td><td></td><td>No Issues Identified</td></tr>
<tr><td>X</td><td>Potential Issues Identified (explain in summary)</td></tr>
<tr><td></td><td>Not Applicable (explain in summary)</td></tr>
</table>

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

1.12 Inspection Notes:

ENB had identified segments by the required date. However, their segment identification continues to evolve as discussed in 1.09. Post the IMP rule date for identifying segments, ENB was constructing a new pipeline. ENB placed a portion of this pipeline in service without first identifying could affect HCA segments.

Integrity Management
Inspection Protocol 2

Baseline Assessment Plan

Scope:
This Protocol addresses the development of the Baseline Assessment Plan. This Plan identifies the integrity assessment method(s) for each pipeline segment that can affect a High Consequence Area, and provides the schedule when these assessments will be performed. This Protocol addresses the selection of assessment methods and the development of an integrated, risk-based prioritized assessment schedule.

Protocol # 2.01	Baseline Assessment Plan: Assessment Methods
Protocol Question	Are the assessment methods shown in the Baseline Assessment Plan appropriate for the pipeline specific conditions and risk factors identified for each segment?

The rule requires that the selected assessment method allow the operator to adequately assess the integrity of the pipeline. The operator's assessment method selection process must exhibit the following characteristics:

1. The assessment methods selected for each segment are effective and appropriate for identifying anomalies associated with the specific risk factors identified for the segment.
2. If ILI tools are used, they are used in combinations that assure the capability to detect corrosion anomalies, deformation anomalies.
3. All of the assessment methods and tools documented in the Baseline Assessment Plan comply with the acceptable methods specified in 195.452 (c) (1) (i).
4. The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
5. Indication/documentation that, if other technology is planned for use, the operator submitted a 90-day notification to OPS regarding the use of other technologies.

Effective Baseline Assessment Plan development would be expected to include:

1. Assurance of corrosion control program effectiveness for line segments that are being hydrostatically tested.
2. Assessments to identify cracks if a pipeline segment is susceptible to cracks or has exhibited crack-like features.

Rule Requirement	§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.
	§195.452 (c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan: (i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. (A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves; (B) Pressure test conducted in accordance with subpart E of this part; or (C) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section ... (iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

Inspection Summary	The inspection team felt that an ongoing crack susceptibility study should have been completed and the results factored into the development of the Baseline Assessment Plan.

Protocol 2.01 Inspection Results		No Issues Identified
	X	Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

2.01 Inspection Notes:

ENB plans to use geometry tools and MFL to perform all of their assessments. Other technologies are not planned to be used. ENB may run crack detection tools in the future dependent on the outcome of their crack susceptibility analysis.

Protocol # 2.02	Baseline Assessment Plan: Assessment Schedule
Protocol Question	Does the Baseline Assessment Plan include a prioritized schedule in accordance with §195.452 (d)?

The rule requires that the operator develop a schedule for assessment of pipeline segments. The operator's Baseline Assessment Plan must exhibit the following characteristics:

1. Identification that all pipeline segments that could affect HCAs are included in the Baseline Assessment Plan. (If the plan identifies line pipe by piggable/testable sections, the documentation should identify a cross reference or other means by which the applicable segments that could affect HCAs can be identified.)
2. Beginning with the highest risk pipe, at least 50% of the line pipe that can affect HCAs are scheduled to be assessed prior to the segments compliance deadline (September 30, 2004 for Category 1 and August 16, 2005 for Category 2).
3. All baseline assessments of the line pipe that can affect HCAs, are scheduled to be completed prior to the compliance deadline (March 31, 2008 for Category 1 pipe, February 17, 2009 for Category 2 pipe, and one year after the pipeline begins operation for Category 3 pipe).

An effective Baseline Assessment Plan should exhibit the following additional characteristics:

1. The schedule appears to be reasonable and achievable.

Rule Requirement

§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: ... (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

§195.452 (c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan ... (ii) A schedule for completing the integrity assessment;

§195.452 (d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows: (1) *Time periods*. Complete assessments before the following deadlines:

If the pipeline is:	Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments:	And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than:
Category 1	March 31, 2008	September 30, 2004
Category 2	February 17, 2009	August 16, 2005
Category 3	Date the pipeline begins operation	Not applicable

Inspection Summary	Process	
	Implementation	

Protocol 2.02 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

2.02 Inspection Notes:

The ENB Baseline Assessment contains a prioritized schedule for assessing testable, or piggable, sections. Appendix A of the HMP identifies each HCA segment, by direct intersect or transport, and the Line in which it is included. ENB will have assessed in excess of 50 percent of the high risk HCA segments before September 30, 2004 and all of the HCA segments by March 31, 2008.

Protocol # 2.03	Baseline Assessment Plan: Risk-Based Assessment Schedule
Protocol Question	Is the prioritized schedule included in the Baseline Assessment Plan established based on the risk factors that reflect the risk conditions for each pipeline segment in accordance with §195.452 (e)?

The rule requires that the operator develop a schedule for assessment of pipeline segments that is prioritized based on the risk associated with a given segment. The operator's assessment schedule must exhibit the following characteristics:

1. A risk based schedule, with the higher risk segments being assessed early in the period required for completion of baseline assessments.
2. The prioritization process considered the risk factors that reflect the risk conditions for each pipeline segment, including, at a minimum, consideration of these risk factors contained in §195.452 (e):
   - Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
   - Pipe size, material, manufacturing information, coating type and conditions, and seam type;
   - Leak history, repair history, and cathodic protection history;
   - Product transported;
   - Operating stress level;
   - Existing or projected activities in the area;
   - Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic conditions);
   - Geo-technical hazards; and
   - Physical support of the segment such as by a cable suspension bridge.

An effective baseline assessment schedule should exhibit the following characteristics:

1. If the Baseline Assessment Plan prioritizes piggable or assessment sections of pipes where the assessment sections include multiple segments that can affect HCAs, the process for determining the relative priority of assessment sections is carefully explained. Furthermore, the methodology assures the highest risk segments that can affect HCAs are scheduled for assessment early in the period allotted for completing baseline assessments.

Rule Requirement	§195.452 (c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan: ... (iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.
	§452 (e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to: (i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate; (ii) Pipe size, material, manufacturing information, coating type and condition, and seam type; (iii) Leak history, repair history and cathodic protection history; (iv) Product transported; (v) Operating stress level; (vi) Existing or projected activities in the area; (vii) Local environmental factors that could affect the pipeline (*e.g.*, corrosivity of soil, subsidence, climatic); (viii) geo-technical hazards; and (ix) Physical support of the segment such as by a cable suspension bridge. (2) Appendix C of this part provides further guidance on risk factors.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>Lack of consideration of 195.452(e)(1) required factor (vi) 'Existing or projected activities in the area" in the process for establishing the baseline assessment schedule.</td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 2.03 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

2.03 Inspection Notes:

The prioritized schedule is based on ENB's Fitness-For Purpose (FPP) process rather than directly on the output of the risk model. The FPP process looks at the results of previous assessments and sets an new assessment interval based upon corrosion growth, crack propagation, etc. The risk model is used to calculate a Consequence of Failure (COF). For pipe sections that are in the top 2/3s of the ranking based on COF, one year is deducted from its assessment interval as defined by the FPP.

Protocol # 2.04	Baseline Assessment Plan: Prior Assessments
Protocol Question	Does the Baseline Assessment Plan make use of prior assessments as baseline assessments?

Assessments performed prior to the effective date of the rule may be used as baseline assessments provided they are consistent with rule requirements for baseline assessments. The operator's Baseline Assessment Plan must exhibit the following characteristics:

1. Evidence that baseline assessments performed after January 1, 1996 but before March 29, 2002, for Category 1 pipelines have been performed using the methods prescribed in §195.452 (c) (1) (i).
2. Evidence that baseline assessments performed after February 15, 1997 but before February 15, 2002, for Category 2 pipelines have been performed using the methods prescribed in §195.452 (c) (1) (i).

Rule Requirement	§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: ... (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.
	§195.452 (d) (2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows: <u>Pipeline</u> — <u>Date</u> Category 1 — January 1, 1996 Category 2 — February 18,1997

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td></td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 2.04 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

2.04 Inspection Notes:

ENB had used assessments performed prior to March 29, 2002 as baseline assessments.

Protocol # 2.05	Baseline Assessment Plan: Updates and Revision Control
Protocol Question	Does the Integrity Management Program adequately assure that updates and revisions to the Baseline Assessment Plan are identified, justified, documented, and implemented consistent with the requirements of §195.452 (c) and (d)?

The rule requires that changes to the Baseline Assessment Plan be justified and documented prior to implementation of the change. The operator's Baseline Assessment Plan and its process for keeping the plan current must exhibit the following characteristics:

1. Plan revisions that have been made subsequent to initial issuance of the plan are properly documented, along with the reason for the change.
2. Provisions for ensuring revisions are documented prior to their implementation.
3. Justification is documented for any segments that are removed from the Baseline Assessment Plan.
4. When new HCAs are identified or the boundaries of existing HCAs change, the pipeline segments that can affect these HCAs are identified and incorporated into the Baseline Assessment Plan.
5. If new segments are added or segments are expanded, the schedule is modified to assure compliance deadlines for baseline assessments are met (1 year from identification to incorporate into the Baseline Assessment Plan and 5 years from identification to perform the assessment).
6. The Baseline Assessment Plan is revised as appropriate to reflect the insights gained from completed assessments as well as other information that might impact the priority or assessment method of future integrity assessments. (For example, if early assessments or other information determine that internal corrosion is a greater problem than previously thought, the operator may elect to use ILI tools with improved ability to discriminate internal wall loss in future assessments and alter the Baseline Assessment Plan accordingly.)

Rule Requirement	§195.452 (c) (2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.
	§195.452 (d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows: ... (3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in § 195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly identified high consequence area within five years from the date the area is identified. (ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

Inspection Summary	1. No requirement to maintain record of changes to BAP. 2. HMP does not capture requirement to update BAP within one year of identifying new HCA segments.

Protocol 2.05 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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2.05 Inspection Notes:

The HMP does not contain any clear direction for maintaining revisions to the BAP. ENB could not identify the requirement within the HMP for incorporating new HCA segments into the BAP within 1 year and assessing within 5 years.

Protocol # 2.06	Baseline Assessment Plan: Completed Assessments
Protocol Question	Inspect to determine if assessments scheduled to be performed prior to the inspection were, in fact, performed and documented.

Inspection of Baseline Assessment Plan implementation should include a check of the following characteristics:

1. Assessments scheduled for completion were, in fact, completed.
2. Assessment methods were used as described in the plan.
3. The date on which assessment field activities are completed is recorded [so the operator understands the time frame allowable for compliance with the provisions of 452 (h)].
4. The total pipeline mileage for which assessments have been completed, and the total mileage that can affect HCAs for which assessments have been completed should be available.

Rule Requirement	§195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: ... (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.
	§195.452 (h) (1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with § 195.422 when making a repair.
	§195.452 (h) (4) *Special requirements for scheduling remediation* (i) Immediate repair conditions.... To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4....

Inspection Summary	Process	
	Implementation	

Protocol 2.06 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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2.06 Inspection Notes:

Several baseline assessments were reviewed. These included:

Line 5 – Mackinaw to Bay City run on 2/28-3/3.
Line 5 – Bay City to Sarnia run on 3/19 to 3/22.
Line 3 – Gretna to Clearbrook run 10/02 – 12/02.
Line 3 – Clearbrook to Superior run 10/02 – 12/02.

All assessments scheduled for 2002 were completed.

Integrity Management
Inspection Protocol 3

Integrity Assessment Results Review

Scope:
This Protocol addresses the review, validation, and evaluation of results from integrity assessments (i.e., in-line inspection, pressure testing, or other technologies). In addressing this program element, this protocol covers verification of information accuracy, the integration of other information about the pipeline with the assessment results to help identify and characterize defects, and obtain an improved understanding about the condition of the pipe.

<table>
<tr><td>Protocol # 3.01</td><td>Integrity Assessment Results Review: Qualifications of Employees that Review and Evaluate Assessment Results</td></tr>
<tr><td>Protocol Question</td><td>Does the operator have a formal, documented process to ensure that employees who review and evaluate integrity assessment results are qualified to perform this work?

Review records such as job descriptions, resumes, training records, etc., to verify that individuals that review assessment results are qualified to do so.</td></tr>
<tr><td colspan="2">The rule requires that individuals who review assessment results and information analysis be qualified to do so. An effective operator program would be expected to require that appropriate means be taken to ensure the requisite level of qualification, and contain the following characteristics:

1. Job description, task analysis, or other means to identify the qualification requirements for performing reviews of assessment results and information analysis, that address education, experience, skills, and training requirements, as appropriate.
2. Documentation of existing personnel skills, education, training, and experience that (1) demonstrates the individual's qualification and proficiency, and (2) identifies additional qualification needs for those individuals that do not meet all qualification requirements.
3. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements.</td></tr>
<tr><td>Rule Requirement</td><td>§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:
(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).</td></tr>
</table>

Protocol # 3.01	**Integrity Assessment Results Review: Qualifications of Employees that Review and Evaluate Assessment Results**
Protocol Question	Does the operator have a formal, documented process to ensure that employees who review and evaluate integrity assessment results are qualified to perform this work? ______________________ Review records such as job descriptions, resumes, training records, etc., to verify that individuals that review assessment results are qualified to do so.

The rule requires that individuals who review assessment results and information analysis be qualified to do so. An effective operator program would be expected to require that appropriate means be taken to ensure the requisite level of qualification, and contain the following characteristics:

1. Job description, task analysis, or other means to identify the qualification requirements for performing reviews of assessment results and information analysis, that address education, experience, skills, and training requirements, as appropriate.
2. Documentation of existing personnel skills, education, training, and experience that (1) demonstrates the individual's qualification and proficiency, and (2) identifies additional qualification needs for those individuals that do not meet all qualification requirements.
3. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>The HMP does not incorporate by reference all associated IM documents. For example, the Qualifications & Training Guideline Document was described as part of ENB,s integrity management process, but was not referenced in the HMP.</td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 3.01 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

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3.01 Inspection Notes:

Internal guidelines and training documents define the job qualifications. Training includes:

Formal training courses including training offered by the vendors.
Attendance at conferences and workshops.
Presentation of papers at conferences and workshops.
Participation in industry associations.
Participation of standards development.

Protocol # 3.02	Integrity Assessment Results Review: ILI Vendor Specifications
Protocol Question	Do the requirements established by the operator for the In-Line Inspection (ILI) assessment process (such as ILI technical specifications, scope of work statements, etc.) assure that those responsible for conducting in-line integrity assessments (i.e., ILI tool vendors) understand their responsibilities in performing integrity assessments that comply with this rule?

ILI tool vendors perform an important role in pipeline integrity. However, the operator is ultimately responsible for the quality of assessments and the validity of tool data analysis. An effective operator program would be expected to have the following characteristics:

1. Documented process by which ILI tool vendors are held accountable for performance that could impact pipeline integrity;
2. Documented specification of services to be provided by ILI vendors;
3. Documented specification of tools (including tool tolerances) to be provided by ILI vendors;
4. Vendor reporting requirements that support the operator's compliance with rule requirements (i.e., no later than 180 days after an integrity assessment);
5. Requirements for vendors to immediately report imminent threats to pipeline integrity;
6. Definition and criteria for vendor ILI data and analysis results that are to be reported to the operator (e.g., type of defect such as internal corrosion, external corrosion, and dents; as well as minimum defect sizes to be reported);
7. Procedures for interacting with the tool vendor to identify and effectively disposition anomalies;
8. Procedures for documenting and approving variances to the vendor's performance specifications; and
9. Qualification of vendor personnel.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section); (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).
	§452 (h) *What actions must an operator take to address integrity issues?* (2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td></td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 3.02 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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3.02 Inspection Notes:

ENB appeared to work with vendors based upon semi-formal agreements due to long standing associations. The normal mechanism for procuring ILI vendor was to release a Request for Proposal that contained few requirements. The one requirement ENB specified was that the preliminary report must be issued within 30 days and the final report within 60 days.

ENB had not been making a determination on repair categories until after the final report had been accepted.

ENB performed periodic assessments of the ILI vendors.

Protocol # 3.03	Integrity Assessment Results Review: Validation of Assessment Results
Protocol Question	Does the operator's integrity assessment results review process provide sufficient assurance that all activities required to validate the in-line inspection data are identified and implemented? ____________________ Review selected verification/calibration dig records to verify that physical pipeline data obtained from field excavations was appropriately used to verify and calibrate ILI results.

After ILI tool runs are completed, an operator may implement a process by which called anomalies are excavated so that tool results may be validated (and/or tool data may be calibrated) using actual, measured defect characteristics, in order to have confidence in the assessment results. An effective operator program would be expected to have the following characteristics:

1. Determination of the appropriate number (representative sample) and type of defects (representative of the different types of anomalies called such as internal corrosion, external corrosion, and dents) for which calibration digs are required.
2. Identification, collection, and documentation of all pertinent information during the calibration dig process, and dissemination to the individuals reviewing assessment results.
3. Field validation digs that assure that the locations of all anomalies are verified, and that collect all information needed to compare the actual anomaly characteristics to the vendor report.

If an operator chooses not to validate/calibrate tool results, an effective operator program would be expected to have documented justification to demonstrate that validation and/or calibration activities are not necessary for its circumstances.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).
	§452 (h) (2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

Inspection Summary		
	Process	The ENB approach to assessment tool tolerances could be clarified in the IMP. For example, the use of unity plots.
	Implementation	

Protocol 3.03 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

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3.03 Inspection Notes:

Once ENB has received, and accepted, the vendor's final report, a dig sheet is prepared for performing field validation digs. The Excavation Program Document contains the information requirements that are to be collected and the dissemination of information within the organization. ENB prepared documents on each dig that included the dig sheet, field generated information, repairs made, and before and after photographs.

ENB also prepared unity plots of as reported versus as found conditions.

Protocol # 3.04	Integrity Assessment Results Review: Integration of Other Information with Assessment Results
Protocol Question	Does the operator's integrity management process documentation require the integration of additional sources of pertinent risk-factor data with the assessment results (either ILI, pressure testing, or "other technology") to support evaluation of the condition of the pipeline, or to make decisions related to the repair or remediation of pipeline defects? ______________________ Review records documenting the operator's review of assessment results to determine if the operator integrates and analyzes all appropriate sources of other information with the assessment data.

The rule requires that operators integrate assessment results with other pertinent information about the risk-conditions of the pipeline to uncover integrity issues that might not be evident from the assessment data alone. An effective operator program would be expected to have the following characteristics:

1. A process to ensure that the analyst is aware of and uses other sources of data in order to make the best integrity decisions (e.g., corrosion control data such as rectifier readings, close interval surveys, or corrosion coupon results).
2. A documented process by which data is collected and disseminated to persons evaluating assessment results.
3. A process that integrates the following types of information, as appropriate:
    - Previous assessment results;
    - Surveillance, testing, and other monitoring data (e.g., internal corrosion coupon monitoring);
    - Historical maintenance and repair information;
    - Uncertainty of assessment results including tool tolerances;
    - Any other information related to pipeline integrity; and
    - Information about how a failure would affect the high consequence area.
4. Consideration of new information such as industry reports on new technology, incident reports, etc.
5. Documentation of the overall results of integrated data analysis and conclusions regarding the integrity of the segment, including the nature of the integrity threats identified, and a reliable characterization of anomalies such as type of anomaly (e.g., internal corrosion, external corrosion, and dents), size (amount of metal loss, depth of dent) and location (e.g., axial location and circumferential orientation).
6. Identification and documentation of integrity issues and potential trends in the integrity of the pipeline.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section). 452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes: (1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment; (2) Data gathered through the integrity assessment required under this section; (3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and (4) Information about how a failure would affect the high consequence area, such as location of the water intake.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td colspan="4">Integration of information/risk analysis results do not appear to have a central role in the overall evaluation of integrity challenges.</td></tr>
<tr><td>Implementation</td><td colspan="4"></td></tr>
<tr><td colspan="2" rowspan="3">Protocol 3.04
Inspection Results</td><td></td><td colspan="3">No Issues Identified</td></tr>
<tr><td>X</td><td colspan="3">Potential Issues Identified (explain in summary)</td></tr>
<tr><td></td><td colspan="3">Not Applicable (explain in summary)</td></tr>
<tr><td colspan="6">Documents Reviewed:</td></tr>
<tr><td colspan="3">Document Number</td><td>Rev.</td><td>Date</td><td>Document Title</td></tr>
<tr><td colspan="3"></td><td>2</td><td>April 28, 2003</td><td>Enbridge HCA Management Manual</td></tr>
<tr><td colspan="3"></td><td></td><td></td><td></td></tr>
<tr><td colspan="3"></td><td></td><td></td><td></td></tr>
<tr><td colspan="3"></td><td></td><td></td><td></td></tr>
<tr><td colspan="6">3.04 Inspection Notes:

ENB did not perform any hydrostatic tests nor has any plans to use other technology. The Excavation Program Guidelines discussed alternative methods of validating data.</td></tr>
</table>

Protocol # 3.05	Integrity Assessment Results Review: Identifying and Categorizing Defects
Protocol Question	Does the operator's process documentation provide adequate guidance to assure the appropriate categorization (and scheduling for repair) of all identified anomalies in accordance with the criteria contained in the rule? ________________________ Review assessment records to verify that defects have been discovered within 180 days of completion of the assessment, that defects have been categorized in accordance with the special requirements for scheduling remediation contained in §452 (h) (4), and that a schedule for repair has been developed.

Upon discovery of a condition, the operator is required to determine if the condition meets any of the rule's special requirements for scheduling remediation. If so, repair or remediation must be scheduled for completion within the time frames established by the rule. An effective operator program would be expected to have the following characteristics:

1. Provisions to ensure that all repair conditions are discovered within 180 days of completion of the assessment.
2. Procedures to ensure that all anomalies are correctly categorized in accordance with the repair provisions of the rule ("immediate repair," 60-day, 180-day, and "other" conditions).
3. Procedures that define the time at which the discovery of an anomaly occurs.
4. Procedures that define actions to be taken if the review cannot be completed within 180 days of assessment completion. (The rule specifically requires that the operator demonstrate that discovery within 180 days is not practical and document this justification.)

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);
	452 (h) (2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.
	452 (h) (4) *Special requirements for scheduling remediation* (i) *Immediate repair conditions* ... (ii) *60-day conditions* ... (iii) *180-day conditions* ... (iv) *Other conditions....*

Inspection Summary	Process	
	Implementation	Several 180 day discovery dates were missed due to delayed ILI vendor reporting.

Protocol 3.05 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

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3.05 Inspection Notes:

The HMP addressed the provision for categorizing repairs within 180 days.
The Excavation Guidelines contains rule requirements for repair categorization and timing requirements.
Definition of "discovery" was contained in the Excavation Guidelines. Discovery was usually not made before the final report was received from the vendor and ENB had accepted the report.
The Excavation Guidelines contained the requirement to notify OPS if discovery could not be made within 180 days.

A review of completed assessments indicated that the 180 day discovery period was exceeded due to the late submission of final reports by the vendor's. Assessments where 180 day discovery was exceeded included:

Line 5 Bay City to Sarnia
Line 3 Gretnal to Clearbrook
Line 2 Gretna to Clearbrook

Protocol # 3.06	Integrity Assessment Results Review: Documentation and Distribution
Protocol Question	Does the operator's process assure the proper documentation and dissemination of assessment report review activities? ____________________ Were results from completed assessments documented and distributed in accordance with procedures?

The documentation and communication of assessment results is an expected part of an operator's process to make effective use of new knowledge about the condition of a pipeline, to make strategic and logistical decisions related to pipeline integrity, and to foster continual improvement. An effective operator program would be expected to have the following characteristics:

1. Requirements to keep records of all integrity assessment reviews.
2. Procedures to distribute assessment review results to those persons or organizational elements that need the information to fulfill their integrity-related responsibilities. (For example, observations about effectiveness of internal and external corrosion control from ILI tool runs are provided to the engineer in charge of corrosion control.)
3. A process to assure that information important to the ILI vendor (e.g., indications of tool inadequacy or inadequate assessment results interpretations) is fed back promptly to the vendor.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).
	§452 (l) *What records must be kept?* (1) An operator must maintain for review during an inspection: (i) A written integrity management program in accordance with paragraph (b) of this section. (ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

Inspection Summary	Process	
	Implementation	

Protocol 3.06 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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3.06 Inspection Notes:

The Excavation Guidelines discussed the process for receiving and assessing ILI vendor inspection results. Document Management Guideline specified record retention as indefinite.

Protocol # 3.07	Integrity Assessment Results Review: Hydrostatic Pressure Testing
Protocol Question	For integrity assessments using hydrostatic pressure testing, has the operator reviewed the test results to determine whether the failures experienced imply that additional assessment activities are needed? ____________________ Review hydrostatic pressure test records to verify that the test complied with Subpart E requirements, that test acceptance was valid, that the cause of all test failures were analyzed and documented, and that appropriate, timely corrective action was taken.

Upon successful completion of a Subpart E hydrostatic pressure test, the pipeline's integrity has been demonstrated, for that point in time. However, analysis of the test failures that occur provides valuable information about the condition of the pipe and the integrity threats to which the pipe is being subjected. Such analyses are a source of data with which other integrity-related data can be integrated for further analysis. An effective operator program would be expected to have the following characteristics:

1. Documentation and evaluation of hydrostatic pressure test failures to understand the cause of the failure (e.g., Was the failure due to hook cracks, selective seam corrosion, internal corrosion, etc?).
2. Metallurgical evaluation of test failures, as required, to assure a full understanding of test failures.
3. Identification, documentation, and analysis of pressure reversals to determine the cause of pressure reversals and identify any integrity threats indicated by the pressure reversals.
4. Test records must document test parameters sufficient to verify compliance with Subpart E requirements.
5. Test procedures and records that document the basis for test acceptance and test validity.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).
	§452 (h) *What actions must an operator take to address integrity issues?* (1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis.
	452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.... (ii) Pressure test conducted in accordance with subpart E of this part;

Inspection Summary	**Process**	
	Implementation	

Protocol 3.07 Inspection Results	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

3.07 Inspection Notes:

No hydrostatic tests were to be performed as Baseline Assessments.

Protocol # 3.08	Integrity Assessment Results Review: Results from the Application of Other Assessment Technologies
Protocol Question	For assessments using "other assessment technology," is the operator's process for evaluation of the results adequate to identify integrity threats? ____________________ Review selected assessment records for assessments conducted using "other technology" to verify that all anomalous conditions or potential defects (including the cause) were analyzed and documented, and that appropriate, timely corrective action was taken.

An operator that chooses to use "other technology" for its integrity assessments is expected to have a documented process to assure that the chosen technology will result in a level of understanding of a pipeline's condition, equivalent to that obtained through the use of accepted ILI tools or a hydrostatic pressure test. An effective operator program would be expected to have the following characteristics:

1. Criteria for the selection of other technology that support major integrity decisions, such as (a) identification of minimum data analysis required, (b) data integration requirements prior to the assessment, (c) assignment of priority to excavations, (d) number of excavation digs required, (e) basis for assessing applicability (e.g., some direct assessment techniques may detect external corrosion but not internal corrosion), and (f) validity of assessment results.
2. Procedures that adequately implement industry accepted practices for the successful use of the technology, including conformance to applicable consensus industry standards.
3. Procedures that address the method by which validation of the results of assessments using alternative technology is conducted.
4. Provisions for identification of excavations required to validate other technology results.
5. Provisions for conducting excavation digs that support the applicability and validity of the assessment technology (as a result, additional information may need to be collected beyond the information that the operator typically collects during an excavation, depending on the specifics of the "other technology" selected).
6. Procedures must address reporting requirements and timing of discovery (180 days from completion of the assessment) and repair conditions (per paragraph 452(h)).

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).
	§452 (h) *What actions must an operator take to address integrity issues?* (1) *General requirements*. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis.
	452 (j) (5) *Assessment methods*. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.... (iii) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

Inspection Summary	Process	
	Implementation	

Protocol 3.08 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

3.08 Inspection Notes:

Other technologies were not planned to be used as baseline assessments or for future re-assessments.

Protocol # 3.09	Integrity Assessment Results Review: Process Formality
Protocol Question	Does the operator have documented guidance or procedures that adequately describe the process steps required to perform a detailed review of assessment results, generate a repair schedule, and perform an integrated evaluation of overall pipeline integrity?

The operator is expected to instill sufficient formality of operations and procedural controls to assure quality reviews of assessment results and adequate records. An effective operator program would be expected to have the following characteristics:

1. Guidance or procedures for conducting reviews of assessment such that qualified persons are able to effectively implement the process.
2. Documented roles and responsibilities, by organizational group or title, for the implementation of required actions.
3. Documentation that specifies the information to be used in reviewing integrity assessment results and the sources of the information.
4. Guidance or procedures that specify records required to be generated in the process of implementing assessment results reviews and integrity evaluations, including records retention and distribution requirements.
5. Quality requirements for the review of assessment results (to assure completeness, accuracy, etc.).

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

Inspection Summary	

Protocol 3.09 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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3.09 Inspection Notes:

ENB had ample documentation to describe IMP programs, processes, and procedures and captured the results of assessments. The only potential weakness was in cross referencing all of the documentation.

Integrity Management
Inspection Protocol 4

Remedial Action

Scope:
This Protocol addresses the operator's remediation of conditions identified through integrity assessments and information analysis that could affect the integrity of a pipeline segment. This includes the process to repair or remediate these conditions in such a manner to assure they will not jeopardize public safety or environmental protection, and to determine if the operator has implemented this remediation process effectively.

Protocol # 4.01	Remedial Action: Process
Protocol Question	Does the operator's Integrity Management Program include a documented process to assure prompt action to address all anomalous conditions that could reduce a pipeline's integrity that are discovered through the integrity assessment or information analysis?

The rule requires the operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. An effective operator program would be expected to contain the following characteristics:

1. A requirement to develop a prioritized schedule for remediation of all identified repair conditions consistent with the repair criteria and time frames found in §195.452(h).
2. A requirement to document justification for changes to the repair/remediation schedule including demonstration that such changes will not jeopardize public safety or environmental protection.
3. A requirement to notify OPS if the operator cannot meet the remediation schedule and cannot provide safety through a temporary reduction in operating pressure.
4. A requirement that if an immediate repair condition is identified, the operating pressure of the affected pipeline be temporarily reduced in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 or the pipeline be shutdown until the condition is repaired. Where pressure reduction cannot be calculated using the method of Section 451.7, the process should identify alternative methods of calculating a safe operating pressure.
5. A requirement that any temporary reduction in operating pressure taken until repair or remediation can be completed cannot exceed 365 days without the operator taking additional remedial actions to assure the safety of the pipeline.
6. A requirement that the operator comply with §195.422 when making a repair.
7. Specification of the records to be generated during the remediation process.

Rule Requirement	§195.452 (h) (1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with § 195.422 when making a repair. §195.452 (h) (3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation.... the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure.
	§195.452 (h) (4) *Special requirements for scheduling remediation.* (i) *Immediate repair conditions....* To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4....

Inspection Summary	The HMP references the use of RSTREGNG todetermine the amount of pressure reduction to be taken for addressing immediate repair conditions. This is contrary to the requirements of 195.452(h)(4)(i), which requires the use of Section 451.7 of B31.4. Timeliness of engineering evaluations to determine the pressure reduction for immediate repair anomalies that can not be addressed by B31.4 formula is not specified in the HMP.

Protocol 4.01 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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4.01 Inspection Notes:

All aspects of Remedial Repair is covered by either the HMP or the Excavation Guideline. An exception was that ENB allowed RSTRENG to be used to determine the allowed pressure reduction should an immediate repair condition be identified. The timeliness of performing engineering assessments for pressure reductions for conditions not covered by ANSI B31 was not specified in the HMP.

Protocol # 4.02	Remedial Action: Implementation
Protocol Question	Has the operator adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis?

The rule requires that an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. The inspection should ensure that:

1. A prioritized schedule was prepared by the operator for remediation of anomalous conditions.
2. Repairs were made in accordance with the operator's prioritized schedule and within the time frames allowed in §195.452(h).
3. Changes to the schedule were justified by the operator and the schedule changes were demonstrated not to jeopardize public safety or environmental protection.
4. OPS was notified in those cases where the schedule could not be met and safety could not be provided through a reduction in operating pressure.
5. For an immediate repair condition, operating pressure was reduced or the pipeline was shutdown.
6. For an immediate repair condition, temporary operating pressure was determined in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 or, if not applicable, the operator should provide an engineering basis justifying the amount of pressure reduction.
7. Operating pressure was not reduced for more than 365 days without the operator taking further remedial action to ensure the safety of the pipeline.
8. Repairs were performed in accordance with §195.422 and applicable industry standards.

Rule Requirement	§195.452 (h) (1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with §195.422 when making a repair. §195.452 (h) (3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation ... the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection.... An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure.
	§195.452 (h) (4) *Special requirements for scheduling remediation* (i) *Immediate repair conditions....* To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4.

Inspection Summary	See inspection notes.

Protocol 4.02 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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4.02 Inspection Notes:

The assessment for Line 4 Plummer to Clearbrook was reviewed. This section was assesses on May 30, 2002. When the vendor's final report was received and accepted by ENB, they had excluded some anomalies from repair as having previously been remediated. In May, 03, they discovered that this was not the case and determined the date of discovery to be 1 May, 2003. The repairs were scheduled to be completed by Nov, 2003. Given the nature of the oversight, the inspection team felt that these should have been repaired immediately.

Integrity Management
Inspection Protocol 5

Risk Analysis

Scope:
This Protocol addresses the overall risk analysis/information analysis process employed by operators to support various integrity management program elements, including Baseline Assessment Plan development, continuing evaluation and assessment of pipeline integrity, and identification of preventive and mitigative measures. The Protocol addresses the comprehensiveness of the risk analysis process, the methods of combining/integrating risk information, input information, the subdividing of pipelines for risk analysis, results, the risk analysis of facilities, and implementation of the risk analysis process. Evaluations of application-specific risk analyses are performed in the respective Protocol area in which they are utilized.

Protocol # 5.01	Risk Analysis: Comprehensiveness of Approach
Protocol Question	Does the operator's process for evaluating risk require consideration of all relevant risk categories when evaluating pipeline segments?

At the onset of examining the operator's process for evaluating risk, it is important to establish the general categories of risk factors that the operator has included in their process. To that end, this protocol question addresses the overall comprehensiveness of the risk evaluation process. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
   - external and internal corrosion
   - stress corrosion cracking
   - materials problems
   - third party damage
   - operator or procedures errors
   - equipment failures
   - natural forces damage
   - construction errors
2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
   - health and safety impact
   - environmental damage
   - property damage
3. Integration of results from the analysis of how pipeline failures could affect high-consequence areas from the segment identification process.

Note: The Protocols are organized such that verification of the use of specific required risk factors in various parts of the rule (e.g., risk factors required for assessment scheduling) is done as part of the protocols for each respective part of the rule, as follows:

Baseline Assessment Plan Factors: Protocol Question 2.03
Continual Assessment Plan Factors: Protocol Question 7.01 and 7.02
Preventive & Mitigative Risk Analysis: Protocol Question 6.02
Leak Detection Evaluation Factors: Protocol Question 6.06
EFRD Evaluation Factors: Protocol Question 6.08

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* ....
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure....
	§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

Inspection Summary	
Inspection Summary	Historical operating data is not being used in the Risk Assessment Model to the fullest extent possible. Weighting factor assigned to third party damage is higher than what is actually being experienced. Decisions regarding preventive and mitigative actions for external and internal corrosion are being made outside of the risk model.

Protocol 5.01 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.01 Inspection Notes:

ENB uses the Bass Trigon developed risk model IAP. Risk is calculated as Likelihood of Failure (LOF) times Consequence of Failure (COF). LOF is composed of weighted risk factors for: Corrosion (31%, Design/Material Defects 33%), System Operations (5%), Natural Forces (3%), and Third Party Damage (28%). COF is composed of weighted risk factors for: Impact on Environment (30%), Impact on population (50%) and Impact on Business (20%). Each of these factors is composed of weighted subfactors.

Protocol # 5.01	Risk Analysis: Comprehensiveness of Approach
Protocol Question	Does the operator's process for evaluating risk require consideration of all relevant risk categories when evaluating pipeline segments?

At the onset of examining the operator's process for evaluating risk, it is important to establish the general categories of risk factors that the operator has included in their process. To that end, this protocol question addresses the overall comprehensiveness of the risk evaluation process. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
   - external and internal corrosion
   - stress corrosion cracking
   - materials problems
   - third party damage
   - operator or procedures errors
   - equipment failures
   - natural forces damage
   - construction errors
2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
   - health and safety impact
   - environmental damage
   - property damage
3. Integration of results from the analysis of how pipeline failures could affect high-consequence areas from the segment identification process.

Note: The Protocols are organized such that verification of the use of specific required risk factors in various parts of the rule (e.g., risk factors required for assessment scheduling) is done as part of the protocols for each respective part of the rule, as follows:

Baseline Assessment Plan Factors: Protocol Question 2.03
Continual Assessment Plan Factors: Protocol Question 7.01 and 7.02
Preventive & Mitigative Risk Analysis: Protocol Question 6.02
Leak Detection Evaluation Factors: Protocol Question 6.06
EFRD Evaluation Factors: Protocol Question 6.08

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....*
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure....
	§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

Inspection Summary	
Inspection Summary	Historical operating data is not being used in the Risk Assessment Model to the fullest extent possible. Weighting factor assigned to third party damage is higher than what is actually being experienced. Decisions regarding preventive and mitigative actions for external and internal corrosion are being made outside of the risk model.

Protocol 5.01 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.01 Inspection Notes:

ENB uses the Bass Trigon developed risk model IAP. Risk is calculated as Likelihood of Failure (LOF) times Consequence of Failure (COF). LOF is composed of weighted risk factors for: Corrosion (31%, Design/Material Defects 33%), System Operations (5%), Natural Forces (3%), and Third Party Damage (28%). COF is composed of weighted risk factors for: Impact on Environment (30%), Impact on population (50%) and Impact on Business (20%). Each of these factors is composed of weighted subfactors.

Protocol # 5.02	Risk Analysis: Integration of Risk Information
Protocol Question	Does the process for evaluating risk appropriately integrate the various risk factors and other information utilized to characterize the risk of pipeline segments?

Methods to evaluate risk utilize a variety of input data to characterize the physical condition of pipelines and the surrounding population/environment for which consequences are estimated. This information, including "risk factors," is typically combined in some fashion (e.g., input into an algorithm or mathematical model, evaluated by subject matter experts, etc.) to produce an estimate of the risk for a particular section of pipe. In some methods used to combine risk information, numerical "weights" are applied to risk factors when calculating or estimating risk. An effective operator program would be expected to have the following characteristics:

1. Inclusion of the pertinent input parameters needed to adequately characterize the relevant risk factors that are identified and integrated into the risk evaluation process (e.g., sufficient information to determine the potential for area-specific external and internal corrosion).
2. A technically justifiable basis for the analytical structure of any tools, models, or algorithms utilized to integrate risk information, and recognition of any limitations of these analytical structures.
3. Logical, structured, and documented processes and guidelines for any subject matter expert evaluations that are used to perform or influence the integration of risk information.
4. Justification for the relative magnitude of any numerical weights used to estimate measures of risk.
5. A risk integration/combination process that emphasizes the potential risk to human health and the environment as compared to "non-safety" risk factors such as those principally associated with business and economic risks.
6. In cases where a risk model is utilized, a method that integrates the risk model output with any important risk factors that were not included in the model to provide a more complete evaluation of the risk.

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* ....
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure ....
	§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

Inspection Summary	Impact of Business was a major consequence contributor in both of the mainline sections reviewed. This appears to be true for all mainline sections.

Protocol 5.02 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

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5.02 Inspection Notes:

Weighting factors were developed using industry standards, system operating history, and special studies.

Some weighting factors do not agree with historical information. For example, third party damage has a weighting factor of 28%; yet, ENB claims their actual operating experience is much lower than this.

Protocol # 5.03	**Risk Analysis: Input Information**
Protocol Question	Are adequate and appropriate data and information input into the risk analysis process?

The overall quality and usefulness of a risk evaluation processes are highly dependent on the validity and quality of input data and information. An effective operator program would be expected to have the following characteristics:

1. Use of the most accurate available data to represent pipeline characteristics in the analysis of different segments, including the results of integrity assessments.
2. Controls to provide assurance of the completeness and quality of input information.
3. Guidance to minimize the use of input information that is unnecessarily or excessively conservative (to avoid masking best-estimate risk insights).
4. Use of sources best suited to provide whatever subjective information is used (e.g., from operator personnel, including field units).
5. Use of a sufficiently structured process for obtaining subjective information (e.g., using forms, surveys, interviews, quality checks, etc.) to ensure that consistent information is provided for different segments.
6. Use of the operator's and industry's collective operating experience data where applicable.

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....*
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure ....
	§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

Inspection Summary	

Protocol 5.03 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.03 Inspection Notes:

A review of the input into the ENB risk model indicated several instances where inaccurate data had been entered or had not been updated based on the latest information available. Where ILI data is available for a line, an Integrated Corrosion Factor (ICF) is used. In one instance the ICF value was indicative of a time between assessments than was actually the case. In another, a value was missing that would have indicated that the pipeline crossed a river.

The Operational Risk Management group solicits input from field units annually.

Protocol # 5.04	**Risk Analysis: Pipeline Subdividing for Risk Analysis**
Protocol Question	For the purposes of evaluating risk, is the operator's pipeline system sufficiently subdivided such that the analysis provides appropriate results, insights, and conclusions?

The manner in which a pipeline is subdivided for the evaluation of risk is an important factor when considering the results of the analysis. An effective operator program would be expected to have the following characteristics:

1. Subdivision units with sufficiently uniform risk characteristics such that results are meaningful and representative when comparing risk at different locations. [Note: The manner in which a pipeline is divided up for the purposes of risk analysis may sometimes differ from "segments" established for segment identification and/or assessment schedules.]
2. An approach for applying risk factors to a pipeline subdivision unit when the factors differ across the unit.
3. A method for relating the subdivision of the pipeline used in risk analysis to: (1) the sectioning of the pipeline defined for the operator's integrity assessments and (2) the segments that can affect high consequence areas.

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* ....
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure ....
	§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

Inspection Summary	

Protocol 5.04 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.04 Inspection Notes:

The ENB risk model calculates a risk score for each HCA segment. This is used to ensure that high risk segments are assessed prior to September 30, 2004. Testable/piggable pipeline sections are given a Consequence of Failure (COF) score that is used to adjust the interval between assessments.

Protocol # 5.05	Risk Analysis: Results
Protocol Question	Are results of the process to evaluate risk useful for drawing conclusions and insights in the operator's Integrity Management Program decision making?

Examination of the application of risk analysis results to specific areas is covered separately in the protocol questions for each applicable Integrity Management program element (e.g., assessment scheduling, preventive and mitigative measures). Overall characteristics of risk results, however, can be examined on a general basis. An effective operator program would be expected to have the following characteristics:

1. Identification of the pipeline locations having the highest estimated risk.
2. Identification of the most important risk drivers for the highest risk locations (e.g., third party damage, internal corrosion, etc.) and the underlying causes (e.g., what conditions are elevating the risk of internal corrosion).
3. The ability to clearly differentiate the relative risks of different pipeline segments.
4. Risk analysis results that account for all modes of pipeline operation (e.g., startup, shutdown, static, and slack line).
5. A means to evaluate and reduce major sources of uncertainties in the process of evaluating risk. [Examples of areas of uncertainty include data and information limitations, subject matter expert opinions, risk model assumptions, and analytical techniques.]

Rule Requirement	§195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....*
	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure ....
	§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

Inspection Summary	

Protocol 5.05 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.05 Inspection Notes:

For the purpose of prioritizing the BAP, the risk model was used to calculate a COF which, in turn, was used to adjust the time interval between assessments. The results of the risk model did not appear to be used to identify dominant risk factors.

For the purpose of identifying Preventive and Mitigative measures, it was planned to use the risk model to identify and quantify projects. The model was not being used in this manner as of yet. Other ways the risk model was being used was for valve placement analysis and dig prioritization.

Protocol # 5.06	Risk Analysis: Facilities
Protocol Question	Are technically adequate approaches used to identify and evaluate the risks of facilities that can affect HCAs?

In addition to line pipe, associated facilities that can affect HCAs are also included in the scope of the Integrity Management rule. While the integrity assessment provisions of the rule apply only to the line pipe, the other provisions of the rule apply to pump stations, break-out tanks, and other equipment if a failure at these locations could affect a high consequence area. Thus, an operator's integrity management program should include processes for addressing these facilities, including the integration of all available information affecting the likelihood and the consequences of equipment or facility failures (i.e., a risk analysis). An effective operator program would be expected to have the following characteristics:

1. Clear documentation of the operator's approach for evaluating the risk of facilities that can affect HCAs.
2. Results that facilitate the determination of measures to reduce facility risks.

Rule Requirement	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§195.452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure.

Inspection Summary	Risk assessment of stations does not consider operator error. MAXIMO is characterized as the fix for flange and fitting leaks and the current risk assessment appears to assume this issue is resolved.

Protocol 5.06 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.06 Inspection Notes:

ENB was in the process of developing a risk assessment methodology for facilities. Observations on facility risk assessment are based on an methodology used by ENB that is independent of the risk model.

Protocol # 5.07	Risk Analysis: Process Formality & Implementation
Protocol Question	Does the operator's integrity management program include a detailed process for the evaluation of risk? Do operator records indicate that the process for the evaluation of risk has been implemented and applied as documented?

The operator is expected to instill sufficient formality of operations and procedural controls to assure quality and that a consistent evaluation of risk is performed. An effective operator program would be expected to have the following characteristics:

1. Documented guidance or procedures describing the process steps required to perform an evaluation of risk.
2. Guidance for the review of results by parties who would be expected to have the requisite technical knowledge to recognize unreasonable results, including operator field organizations.
3. Requirements for adequate training to all participants in the evaluation of risk.
4. Assigned responsibility, by organizational group or title, for the implementation of required actions.
5. Guidance for the distribution of risk evaluation results.
6. Guidance regarding records to be generated and retained (including retention duration).
7. Communication of results to the operator's organizational units and application of results in operator decision processes.

Rule Requirement	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
	§195.452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure ....

Inspection Summary	Process	The requirements for qualification of risk analysis personnel is not well documented in the HMP.
	Implementation	

Protocol 5.07 Inspection Results		**No Issues Identified**
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

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5.07 Inspection Notes:

ENB had a detailed description of their risk model. The documentation consisted of four volumes with process description, description of algorithms and weighting factors, Appendices, and an Introduction.

Protocol # 5.08	Risk Analysis: Revision of Process
Protocol Question	Does the process for evaluating risk include steps to review and update assumptions, input information and supporting tools as necessary? Do operator records indicate that the process for update and revision of the risk evaluation process has been implemented as described?

Along with having a process to evaluate risk, it is also important to keep the analysis up to date with respect to the evaluated pipelines and facilities. An effective operator program would be expected to have the following characteristics:

1. A means to assure the risk analysis reflects the current pipeline configuration and operation (e.g., valve additions, changes in commodities).
2. A means to assure the risk analysis reflects the current pipeline material condition and maintenance/surveillance program activities (e.g., feedback from integrity assessments and repairs, updated cathodic protection information, internal corrosion coupon data).
3. A means to assure the risk analysis reflects up to date consequence characteristics in the vicinity of the pipeline (e.g., population growth along right of ways).
4. Control of the process such that changes to the risk evaluation process are documented (e.g., revisions to input information, expert panel re-evaluations, changes in analytical model versions).
5. A periodic review of all risk analysis tools and methods to determine the need for any updates.

Rule Requirement	§195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); §195.452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure ....

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>The Risk Assessment team must solicit input from field organizations rather than having the field input information based on trigger points.</td></tr>
<tr><td>Implementation</td><td>Updates to the risk model may not be made in a timely manner. For example, the Integrated Corrosion Factor for the Cass Lake to Deer River pipeline section had not been updated although the assessment had been completed in 2001.</td></tr>
</table>

Protocol 5.08 Inspection Results		
		No Issues Identified
	X	**Potential Issues Identified (explain in summary)**
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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5.08 Inspection Notes:

The HMP includes a flow chart process for updating the risk model.

Integrity Management
Inspection Protocol 6

Preventive and Mitigative Measures

Scope:
This Protocol addresses the evaluation of preventive and mitigative measures, and is divided into three parts:

1. Questions applicable to all areas of the preventive and mitigative measures evaluation, including risk analysis requirements (§194.452(i)(1)-(i)(4));
2. Questions specific to the evaluation of leak detection system capabilities and the need for upgrades (§194.452(i)(3));
3. Questions specific to the evaluation of the need for installation of additional EFRDs (§194.452(i)(4)).

Note: While this Protocol addresses the specific requirements for <u>application</u> of risk analysis to the evaluation of preventive and mitigative measures, the overall adequacy of the operator's risk analysis <u>process</u> is separately covered in Protocol Area 5, Risk Analysis.

Protocol # 6.01	Preventive & Mitigative Measures: Actions Considered
Protocol Question	Does the process to identify additional preventive and mitigative actions include consideration of risk and cover a broad spectrum of alternatives? [Note: Leak detection and EFRDs are covered in more detail in subsequent questions within this protocol.] ——————— Do operator records provide documentation of the preventive and mitigative actions that have been considered?

The integrity management rule requires operators to "take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area." An effective operator program would be expected to have the following characteristics:

1. Identification of the most significant causes/drivers of location-specific risk (e.g., third party damage, internal corrosion, etc.) when evaluating additional preventive and mitigative actions for those locations.
2. Identification of potential preventive and mitigative actions that address the most significant location specific risks, including consideration of preventive and mitigative actions listed in §195.452(i)(1).
3. Review of the effectiveness of current preventive and mitigative actions and the potential for enhancements and upgrades.
4. Consideration of a spectrum of modifications, ranging from incremental improvements to major changes.
5. Consideration of changes to both documented work processes (e.g., procedures, response plans) and physical changes.
6. Consideration of additional preventive and mitigative actions for non-pipe facilities that can affect an HCA.

Rule Requirement	§195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

Inspection Summary	Process	
	Implementation	

Protocol 6.01 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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6.01 Inspection Notes:

The process for identifying Preventive and Mitigative measures was still in the implementation phase. It was anticipated that the risk model would be used during the 2004 budget process to identify and help justify P&M projects.

Protocol # 6.02	Preventive & Mitigative Measures: Risk Analysis Application
Protocol Question	Does the process effectively evaluate the effects of potential actions on reducing the likelihood and consequences of pipeline releases?

Operators must conduct a risk analysis as part of the evaluation of preventive and mitigative measures, including a number of specific risk factors. In addition to the required set of factors, there are other factors that are relevant to the preventive and mitigative measures evaluation. An effective operator program would be expected to have the following characteristics:

1. Consideration of all risk factors required by §195.452(i)(2) in the risk analysis applied to the preventive and mitigative measures evaluation. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. A risk analysis process that addresses all other relevant factors that constitute a threat to pipeline integrity (e.g., external and internal corrosion, third party damage, operator or procedures error, equipment failures, natural forces damage, stress corrosion cracking, materials problems, construction errors, various operating modes).
3. A risk analysis process that addresses all other relevant important consequences of pipeline failures (e.g., population impacts, environmental damage, property damage).
4. Measures to assure that the analysis is up to date prior to use (e.g., pipeline data and configuration assumptions verified to be current prior to evaluating the relative impact of a proposed preventive or mitigative measure).

Rule Requirement	§195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection ... (2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: (i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area; (ii) Elevation profile; (iii) Characteristics of the product transported; (iv) Amount of product that could be released; (v) Possibility of a spillage in a farm field following the drain tile into a waterway; (vi) Ditches along side a roadway the pipeline crosses; (vii) Physical support of the pipeline segment such as by a cable suspension bridge; (viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

Inspection Summary	

Protocol 6.02 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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6.02 Inspection Notes:

The risk model contains all of the factors necessary to be an effective tool in identifying P&M projects and quantifying risk reduction potential.

Protocol # 6.03	Preventive & Mitigative Measures: Decision Basis
Protocol Question	Does the process provide an adequate basis for deciding which candidate preventive and mitigative actions are implemented? ——— Do operator records indicate that the decision making process has been applied as described?

The process and decision criteria used by an operator to decide if potential actions are to be implemented or rejected are a critical part of the preventive and mitigative measure process. An effective operator program would be expected to have the following characteristics:

1. A systematic decision-making process involving input from relevant parts of the organization such as operations, maintenance, engineering, corrosion control, etc., that considers the results of the risk analysis along with other information in making decisions about which preventive and mitigative actions to implement.
2. Priority in schedule and scope for additional actions on the highest risk lines and facilities.
3. A defined basis regarding how much benefit (e.g., risk reduction, reduction in threat to integrity, etc.) is necessary for additional actions to be evaluated for potential implementation.
4. Integration of approved preventive and mitigative actions with the operator's work processes responsible for scheduling and implementing the approved actions (e.g., budgeting, project management, maintenance).
5. Documentation of candidate preventive and mitigative measures that have been considered, including those that have not been implemented.
6. Implementation of approved additional actions as previously planned and scheduled.

Rule Requirement	§195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection ....

Inspection Summary		
	Process	
	Implementation	

Protocol 6.03 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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6.03 Inspection Notes:

ENBs P&M implementation process using the IAP risk model is still being implemented.

Protocol # 6.04	Preventive & Mitigative Measures: Process Formality and Implementation
Protocol Question	Is the operator's process for identifying and evaluating preventive and mitigative measures to protect HCAs documented with sufficient specificity and detail to provide assurance that it can be implemented in a technically sound and consistent manner? ——— Do operator records indicate that the process has been implemented as described?

A process for evaluating additional preventive and mitigative measures is a key element of an operator's integrity management process. After review of process details in the preceding questions, the inspection team should evaluate the governing process that the operator uses to evaluate additional preventive and mitigative measures. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all major additional preventive and mitigative evaluation areas (general additional measures, Leak Detection, and EFRDs).
2. Evaluation of additional preventive and mitigative measures in a timely manner for segments after integrity assessments are conducted on that segment or other events occur that indicate a need for re-evaluation (e.g., unsatisfactory detection or mitigation of an actual leak).
3. Technical justification or validation of key assumptions, including references to any specific sections of industry standards as applicable.
4. Mechanisms to assure technical quality such as independent review, peer review, external audit, etc.
5. Requirements to assure that relevant pipeline and facility changes are identified and incorporated into any updates to preventive and mitigative evaluations (e.g., interfaces with the system modification/change control process).
6. Assigned responsibilities for implementing all required actions (e.g., by organizational group or title).
7. Specification of records to be generated and the associated retention period. [Note: Retention requirements may be in a separate document retention policy.]
8. Updating the evaluation of preventive and mitigative measures at the frequency specified in the Integrity Management Plan.

Rule Requirement	§195.452(f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at a minimum, each of the following elements in its written integrity management program: (6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

Inspection Summary	Process	
	Implementation	

Protocol 6.04 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

6.04 Inspection Notes:

ENB's process for identifying P&M measures was still being implemented.

Protocol # 6.05	Leak Detection Capability Evaluation: Installed Leak Detection System Information
Protocol Question	What leak detection capability is installed on pipelines and facilities that are classified as being able to affect an HCA? [Note: As there may be multiple types of leak detection installed on different portions of the pipeline system, the types/categories of leak detection that are in use are listed first, then applied in the table that follows.] Types/Categories of operator leak detection capabilities [e.g., visual observation of pipeline, external field sensors, operations personnel watching pressure gauges, SCADA pressure/flow alarms, Over-Short reports, computerized analysis, modeling, etc.]: 1. 2. 3. 4. 5. Applicable Pipeline Section — Leak Detection Type/Category — Frequency of Monitoring — Actions Required on Suspect Condition
Rule Requirement	§195.452 (i)(3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

Inspection Summary	

Protocol 6.05 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (Explain in Summary)

Documents Reviewed:

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6.05 Inspection Notes:

All lines, except for Line 6, has CPM capability. CPM will be operational on line 6A in 2003 and on line 6B in 2004.

Protocol # 6.06	Leak Detection Capability Evaluation: Evaluation Factors
Protocol Question	Does the process for evaluating leak detection capability adequately consider all of the §195.452(i)(3)-required factors and other relevant factors? Do operator records indicate that all required and other relevant factors have been evaluated?

As part of the leak detection-specific portion of the preventive and mitigative section of the integrity management rule, a number of factors are required to be part of the operator's evaluation. In addition to the required set of factors, there are other factors that are relevant to the evaluation of the operator's leak detection capability. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all eight of the required §195.452(i)(3) evaluation factors, including risk assessment results. If all required factors are not considered, a documented basis for the exclusion of certain listed factors. [Note: Risk analysis details are covered in protocol question 6.02.]
2. Identification and evaluation of a sufficient spectrum of leak scenarios to adequately determine the overall effectiveness of leak detection capability (e.g., "most likely" in addition to "maximum possible").
3. Consideration of additional evaluation factors such as:
   - current leak detection method for the HCA areas,
   - use of SCADA,
   - thresholds for leak detection,
   - flow and pressure measurement,
   - specific procedures for lines that are idle but still under pressure,
   - additional leak detection means for areas in close proximity to sole source water supplies, and
   - testing of leak detection means (such as physical removal of product from the pipeline).
4. Evaluation of all modes of line operations including slack line, idled line, and static conditions.
5. If a computational pipeline monitoring technique is part of the leak detection systems, design, maintenance, controller training, and record-keeping aspects of API 1130 are addressed in system design and maintenance practices.
6. Evaluation of leak detection performance during transient conditions, and a strategy to manage any short-term reduced performance.
7. Evaluation of the operational availability and reliability of the leak detection systems, and the operator's process to manage system failures.
8. Consideration of enhancements to existing leak detection capability (e.g.,increasing the monitoring frequency of existing techniques).
9. Consistent application of a risk-based decision-making process for leak detection, as described in protocol question 6.03.

Rule Requirement	§195.452 (i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

Inspection Summary	Process	
	Implementation	

Protocol 6.06 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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6.06 Inspection Notes:

Enbridge will have CPM installed on all of its lines by 2004. Per ENB's HMP "Additions, enhancements and further development to the Mass Balance System will be prioritized based on HCA segment risk output for the mainline risk assessment. The length and size of pipe, type of product carried, proximity to HCA, swiftness of leak detection, location of the nearest response personnel, leak history, and risk assessment results are inputs to the prioritization".

ENB has just begun a program to look at leak thresholds, using the methods outlined in API 1149, on all pipelines and at all locations along the pipeline, then to develop leak test methods and test parameters for all pipelines. This is a two year project The study will include a specific examination of the thresholds.

ENB tests its CPM by either withdrawing liquid from the pipeline to simulate a leak or by introducing SCADA data from an actual leak.

Protocol # 6.07	Leak Detection Capability Evaluation: Operator Actions/Reactions
Protocol Question	Does the process adequately consider and document operator actions and reactions associated with leak detection systems?

The role of operations personnel is critical in responding to leak detection indications as well as making certain that leak detection systems are operating correctly. An effective operator program would be expected to have the following characteristics:

1. A documented basis for all operator reactions credited in the leak detection evaluation (e.g., operational procedures and/or training materials). [Note: This does not imply that integrity management-specific operator procedures and/or training are anticipated. Operator responses assumed in the leak detection evaluation, however, should be based on verifiable operational expectations versus arbitrary assumptions.]
2. Measures applied to assure that required actions are accomplished and prudently restored if varying modes of pipeline operations require controllers or other personnel to engage/activate or mute/disable certain attributes of the overall leak detection capabilities.
3. Integration of emergency response procedures and incident mitigation plans with associated leak detection indications.
4. Adequate guidance in documented work processes to assure that operating personnel have the authority and responsibility to initiate reaction measures and to shutdown the pipeline if warranted.
5. Assurance that supervision is always promptly available for contact if procedures require that operating personnel contact supervision prior to initiating response actions and/or shutting down the pipeline.

Rule Requirement	§195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

Inspection Summary	

Protocol 6.07 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

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6.07 Inspection Notes:

For the purposes of spill volume, ENB has taken credit for a 5 minute SCADA response time to identify a leak and a three minute operator response time to isolate the leak.

Per the SCADA procedure, if the indication of a leak is obvious, then shutdown is immediate. If the indication is not obvious, then shutdown occurs in 10 minutes and the investigation continues.

Protocol # 6.08	EFRD Need Evaluation: Factors
Protocol Question	Does the process for evaluating the need for additional EFRDs adequately consider all of the 195.452(i)(4)-required factors and other relevant factors? ——————— Do operator records indicate that all required and other relevant factors have been evaluated?

As part of the EFRD-specific portion of the preventive and mitigative section of the integrity management rule, a number of factors are required to be part of the operator's evaluation. In addition to the required set of factors, there may be other factors that are relevant to the evaluation of the need for additional EFRDs. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all ten of the required 195.452(i)(4) evaluation factors, including consideration of the benefits of reduced consequences expected due to reducing spill size. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. Consideration of any additional relevant line-specific factors beyond those listed in 195.452(i)(4) (e.g., the relative reliability of existing or proposed EFRDs, any relevant operating modes beyond nominal full flow conditions, etc.).
3. Consideration of risk analysis results, including identification of highest risk segments. [Note: Risk analysis details are covered in protocol question 6.02.]
4. As part of the "swiftness of leak detection and pipeline shutdown capabilities" factor, consideration of system detection times, operator response times, remotely controlled valve response characteristics, and system isolation time assessments, as applicable.
5. Evaluation of the need for additional EFRDs to respond to releases during transient conditions.
6. Consideration of the potential effects of additional EFRDs, including a) conducting proper valve sequencing during intended EFRD activations, b) the operator's ability to promptly detect and react to inadvertent EFRD activations, and c) possible elevated pressures caused by transient conditions during EFRD activations.
7. Consistent application of a risk-based decision-making process for additional EFRDs, as described in protocol question 6.03.

Rule Requirement	§195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors - the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of the nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

Inspection Summary	Process	
	Implementation	

Protocol 6.08 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

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6.08 Inspection Notes:

Minimization of spill volume through the use of EFRDs is one application that the risk assessment model is currently being used for. All of the factors of 195.452(i) are evaluated in the placement of additional EFRDS.

Integrity Management
Inspection Protocol 7

Continual Process of Evaluation and Assessment

Scope:
This Protocol covers the requirements for conducting periodic integrity assessments based on the results of operator evaluations of pipeline integrity. This Protocol addresses the adequacy of re-assessment methods and intervals, compliance with the 5-year maximum re-assessment interval, and adequacy of any notifications for variance from the 5-year interval.

Protocol # 7.01	**Continual Process of Evaluation and Assessment: Periodic Evaluation and Assessment Intervals**
Protocol Question	Does the operator have an adequate process for performing periodic integrity evaluations and determining re-assessment intervals for pipeline segments that could affect HCAs?

An operator must have an approach to periodically evaluate the integrity of the pipeline and to determine future integrity assessment plans. The periodic evaluation and assessment process must include the following provisions:

1. An evaluation of pipeline integrity is performed periodically to update the operator's understanding of pipe condition and the location-specific integrity threats for segments that can affect HCAs. The results of this evaluation are used to establish the intervals for future integrity assessments and the assessment methods to be used (see question 7.02).
2. The re-assessment intervals are based on all risk factors associated with the pipeline and adequately consider, as a minimum the following:
    - Those risk factors listed in paragraph 452 (e):
    - Results of previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
    - Pipe size, material, manufacturing information, coating type and conditions, and seam type;
    - Leak history, repair and remediation history, and cathodic protection history;
    - Product transported;
    - Operating stress level;
    - Existing or projected activities in the area;
    - Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic conditions);
    - Geo-technical hazards; and
    - Physical support of the segment such as by a cable suspension bridge.
    - All information analysis (risk analysis) results required by paragraph 452 (g); and
    - Prior and pending decisions about preventive and mitigative actions.
3. Each segment is re-assessed on a schedule not to exceed five years.

An effective program should exhibit the following additional characteristics:

1. The Integrity Management (IM) Program contains requirements to conduct periodic integrity evaluations that are technically rigorous and adequate for making integrity related decisions.
2. The IM Program includes a process for capturing and evaluating new information to determine if changes to the assessment schedule might be necessary.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);
	§195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (2*) Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section). (3) *Assessment Intervals.* An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

Inspection Summary	Process	
	Implementation	

Protocol 7.01 Inspection Results		
	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

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7.01 Inspection Notes:

ENB uses the Fitness-For-Purpose process for determining re-assessment intervals. The Consequence of Failure score from the IAP risk model is used to determine if the re-assessment interval should be reduced by one year for those testable sections with high COF scores.

Protocol # 7.02	Continual Process of Evaluation and Assessment: Assessment Methods
Protocol Question	Do the assessment methods shown in the continual assessment plan appear to be appropriate for the pipeline specific conditions and risk factors being evaluated?

The rule requires that the selected assessment method allow the operator to adequately assess the integrity of the pipeline. The operator's assessment method selection process must exhibit the following characteristics:

1. The assessment methods selected for each segment are appropriate for the specific integrity issues and risks identified for the segment.
2. The process for assessment method selection includes consideration of completed assessment results.
3. If ILI tools are used, they are capable of detecting corrosion and deformation anomalies.
4. The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
5. If technology other than pressure testing or in-line inspection is planned for use, the operator submits a notification to OPS at least 90 days before conducting the assessment.

An effective operator program would be expected to have the following characteristics:

1. For line segments that are being hydrostatically tested, the operator performs a comprehensive review of corrosion control program effectiveness for these locations.
2. If the operator has reason to suspect a pipeline segment is susceptible to cracks or has exhibited crack-like features, the re-assessment method selection process should address assessment of cracks.
3. If the operator has reason to suspect a pipeline segment is susceptible to internal corrosion, the re-assessment method selection and subsequent data integration should address this threat.
4. The methods used to conduct re-assessments are periodically reviewed and modified if necessary based on new insights from baseline assessments, the results of information integration and risk analysis, and to allow use of new, improved assessment technologies.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);
	§195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. (i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves; (ii) Pressure test conducted in accordance with subpart E of this part; or (iii) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conduction the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

Inspection Summary	

Protocol 7.02 Inspection Results	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

7.02 Inspection Notes:

ENB provides detailed explanations in the Line Description Documents for the ILI tool chosen. ENB does not plan to perform any hydrostatic tests as baseline assessments.

Protocol # 7.03	Continual Process of Evaluation and Assessment: Assessment Interval Variance
Protocol Question	Does the operator's IM Program include provisions for submitting variance notifications to OPS for assessment intervals longer than the 5-year maximum assessment interval?

The Rule contains provisions for exceeding a 5 year re-assessment interval under certain circumstances. If an operator desires a variance from the 5 year interval, it must notify OPS of its intentions. The variance must be based upon an engineering analysis or the unavailability of the technology to be used for the assessment. The operator's notification to OPS must contain the following characteristics:

1. Engineering Justification Requirements
   - Notification time frame - 270 days before the end of the five year re-assessment deadline;
   - Describe use of other technology such as external monitoring to provide equivalent understanding of the condition of the line pipe; and
   - Propose an alternate interval.
2. Unavailable Technology Requirements
   - Notification time frame - 180 days before the end of the five year re-assessment deadline;
   - Demonstrate interim actions to evaluate integrity of pipeline segment; and
   - Provide an estimate of when assessment can be completed.

An effective operator program would be expected to have the following characteristics:

1. The operator's IM Program contains requirements for technically rigorous and documented engineering justifications for extending assessment intervals.
2. Evaluation of historical and current integrity information is performed to determine a new assessment interval period.
3. The operator pro-actively identifies and addresses issues that could adversely impact meeting assessment schedules.
4. The operator's IM Program adequately documents justifications for extending assessment intervals due to unavailable technology.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); §195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (4) *Variance from the 5-year intervals in limited situations* - (i) *Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j) (5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section. (ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address specified in paragraph (m) of this section.

<table>
<tr><td rowspan="2">Inspection Summary</td><td>Process</td><td>The HMP does not explicitly address the "unavailable technology" 180 day notification.</td></tr>
<tr><td>Implementation</td><td></td></tr>
</table>

Protocol 7.03 Inspection Results		
		No Issues Identified
	X	Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

7.03 Inspection Notes:

The re-assessment schedule for ENB has intervals that are in excess of 5 years. The comment section associated with these assessments notes that OPS notification is required.

Protocol # 7.04	Continual Process of Evaluation and Assessment: Process Formality
Protocol Question	Does the operator have documented guidance or procedures that adequately describe the process steps required to provide continual evaluation and assessment of pipeline integrity?

The operator is expected to instill sufficient formality of operations and procedural controls to assure periodic evaluation of the integrity of the pipeline and to determine future integrity assessment plans. An effective operator program would be expected to have the following characteristics:

1. Guidance or procedures for conducting periodic integrity evaluations such that qualified persons are able to effectively implement the process.
2. Documented roles and responsibilities, by organizational group or title, for the implementation of required actions.
3. Documentation that specifies the information to be used in determining integrity assessment methods and assessment intervals, and the sources of this information.
4. Guidance or procedures that specify records required to be generated in the process of determining integrity assessment methods and assessment intervals and in preparing notifications.
5. Records retention and distribution requirements.

Rule Requirement	§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

Inspection Summary	

Protocol 7.04 Inspection Results		
	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

7.04 Inspection Notes:

The elements for determining re-assessment intervals are described in the HMP e.g., defect growth rate analysis, causal factor susceptibility analysis. The Line Description Documents provide the details for tool selection and assessment interval based on the FPP process. Because interpretation of past ILI results is integral to the FPP process, complete and adequate development of a prescriptive process is not possible. The process is well documented beginning with detailed reports on growth analysis, crack susceptibility, the LDD, and the comment section of the BAP.

Protocol # 7.05	**Continual Process of Evaluation and Assessment: Process Implementation**
Protocol Question	Inspect to determine if periodic integrity evaluations and the determination of future assessment methods and intervals are being performed as required by the rule, and are consistent with the operator's program documentation.

Inspection should include a review of operator documentation and records for the following:

1. Results of periodic integrity evaluations specifying the integrity assessment methods and intervals for segments that have received baseline assessments.
2. Adequate technical justification for the selection of assessment methods and intervals, including evidence that previous assessment results and other relevant information was used.
3. Timely determination of future assessment methods and intervals.
4. Documentation indicating that re-assessments scheduled for completion were, in fact, completed.
5. Technical justification and other records to support any operator notifications for variance from the 5 year re-assessment interval.

Rule Requirement	§195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*

Inspection Summary	Process	
	Implementation	

Protocol 7.05 Inspection Results	X	**No Issues Identified**
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

7.05 Inspection Notes:

The HMP provided a schedule for future assessments along with an identification of the assessment method. Some re-assessment intervals were longer than 5 years and it is expected ENB will request a variance from OPS in the future.

Integrity Management
Inspection Protocol 8

Program Evaluation

Scope:
This Protocol addresses the requirement to measure whether the Integrity Management (IM) Program is effective in assessing and evaluating integrity and in protecting the high consequence areas. This Protocol addresses periodic internal reviews or audits of the IM Program, threat specific and aggregate program-wide performance measures, program goals, trend analysis, root cause analysis, and communication of program results and lessons learned.

Protocol # 8.01	Program Evaluation: Process Approach
Protocol Question	Inspect the operator's IM Program to verify that it includes a process for performing IM Program evaluations as required in §195.452 (f) (7).

An operator's Integrity Management (IM) Program must include a process to measure whether the program is effective in assessing and evaluating pipeline integrity and in protecting the high consequence areas. The purpose of this protocol is to perform an inspection of the operator's approach to evaluate the effectiveness of its IM Program processes and methods used to perform each IM Program element in 195.452 (f). An effective operator program would be expected to have the following basic characteristics:

1. The use of periodic self assessments, internal/external audits, management reviews, or other self critical evaluations to assess program effectiveness.
2. A description of the scope, objectives, and frequency of periodic evaluations.
3. Clear performance goals and objectives to measure the effectiveness of key integrity activities.
4. Clear assignment of responsibility, by organizational group or title, for implementing required actions.
5. A description of specific records to be generated in the process of implementing IM Program Evaluation, including but not limited to records from completed audits and other program reviews, and records documenting dispositioned recommendations.
6. Review and follow-up of program evaluation results, findings, and recommendations, etc., by appropriate company managers.
7. A means to update the performance measures (if needed) to assure they are providing useful information about the effectiveness of IM Program activities.

The adequacy of specific performance metrics is the subject of Protocol 8.02.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

<table>
<tr><td>Inspection Summary</td><td colspan="4"></td></tr>
<tr><td rowspan="3">Protocol 8.01
Inspection Results</td><td>X</td><td colspan="3">No Issues Identified</td></tr>
<tr><td></td><td colspan="3">Potential Issues Identified (explain in summary)</td></tr>
<tr><td></td><td colspan="3">Not Applicable (explain in summary)</td></tr>
</table>

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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8.01 Inspection Notes:

The HMP calls for ENB's program to be reviewed annually. ENB has established a steering committee that is responsible for establishing and maintaining the overall HMP. The steering committee is comprised of: the Manager, U.S. Compliance and Risk Management, Pipeline Integrity, Safety & Environment, Operations Services, SCADA, Control Center Operations, Engineering Operations, and Compliance and Risk Management.

The three main responsibilities of the steering committee are:

- Identify any issues or situations that could occur that may potentially impact the program
- Relay information to affected steering committee members regarding recommended program changes
- Follow up to ensure appropriate changes were made during annual review process.

The steering committee meets via teleconference whenever issues arise that warrant the attention and discussion of the committee.

Protocol # 8.02	Program Evaluation: Performance Metrics
Protocol Question	Inspect the operator's IM Program to determine if the operator has selected an adequate set of performance metrics to provide meaningful measure of the IM Program performance and effectiveness in reducing risk.

The purpose of this protocol is to review the specific IM Program performance metrics to determine if they can reasonably be expected to effectively assess and evaluate the IM Program. An effective process for evaluating IM Program performance would be expected to include the following characteristics:

1. A description in the IM Program document of the type and frequency of performance metrics to be used.
2. Overall program metrics including (a) overall measures of program effectiveness such as number of leaks, volume released, etc, and (b) measures that reflect the accomplishment of the program's objectives such as number of miles of pipeline assessed; number of anomalies found requiring repair or mitigation; number of right-of-way encroachments.
3. Threat specific metrics, such as: number of leaks caused by internal/external corrosion; anomalies from manufacturing defects; third party damage; operator error; over-fill/over-pressure (tanks); equipment or non-pipe problems.
4. Defined performance goals that address IM Program areas as well as segments specific issues related to the operator's unique operating environment.
5. Bench-marking company performance using data from outside the company (e.g., PPTS).
6. Trending of equipment or material failures as a means to evaluate pipeline deterioration (an indicator of the end of useful life of materials and components), including a method to establish the magnitude of trends that represent normal fluctuations versus significant deviations (i.e., significant enough to warrant corrective action).
7. Trending of "near-misses" (such as inadvertent over-pressurization, right-of-way encroachments without one-call notification, SCADA outages, relief valve operation, etc.).

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

Inspection Summary	

Protocol 8.02 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

8.02 Inspection Notes:

ENB has adopted the ten required performance measures from API 1160.

Other programs that are used to measure performance include:

Release Database – tracks and trends releases.
API – PPTS – ENB participates in API's Pipeline Performance Tracking System. PPTS provides credible information and meaningful statistics reflecting pipeline risk factors.
Pipeline Integrity Tracking System – Can be queried to illustrate the number and location of excavations.
MAXIMO – Tracks events that could affect pipeline integrity.

Protocol # 8.03	Program Evaluation: Communication of Evaluation Results
Protocol Question	Does the Program Evaluation process require communication of goals and results of the IM Program effectiveness to managers and workers involved with IM Program implementation?

The purpose of this protocol is to ensure that the operator adequately communicates the results of the program evaluations to the proper areas/personnel in the company that may need to utilize the information. An effective program would be expected to have the following characteristics:

1. Periodic reports on the IM Program performance that are prepared and distributed to responsible field and headquarters managers.
2. Communications of performance evaluation results that provide an accurate and thorough summary and trending of IM Program performance, as well as information on the most important integrity issues and actions taken to address these issues.
3. Management follow-up of significant integrity issues and actions taken to address these issues.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

Inspection Summary	

Protocol 8.03 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
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8.03 Inspection Notes:

The HMP presented a flow chart of the performance measure collection and analysis process. As part of the process, information is compiled and issued in an annual report. Distribution of the report is not specified; however, the process recognizes that proper dissemination must be identified.

Protocol # 8.04	Program Evaluation: Root Cause Analysis Process
Protocol Question	Does the operator have an effective root cause analysis and a lessons learned program? Is the process being effectively implemented?

The insights obtained from root cause analysis of incidents, leaks, and near-misses can be important to improving performance. The purpose of this protocol is to review the use of root cause analysis and to evaluate how lessons learned are communicated in the organization. The following characteristics would be expected to be included in an effective root cause analysis process:

1. Rigorous and complete analyses of problems affecting risk that address the identification of human factors issues, management systems problems, generic component or process failures, positive trends, and system wide implementation of good practices.
2. Rigorous and complete identification of recommendations and corrective actions; and thorough tracking and follow-up of these actions to ensure completion.
3. Lessons learned from root cause analysis of incidents developed and distributed to appropriate company employees.

Review examples involving significant problems and determine the adequacy of the analysis and proposed corrective actions. Select several proposed corrective actions from the root cause analysis that was reviewed and determine if the actions have been completed, or are scheduled for completion in a timely manner.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

Inspection Summary	

Protocol 8.04 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

8.04 Inspection Notes:

ENB has an Incident Investigation in place. ENB recognizes that this method can be deficient due to inconsistencies in investigative methods and the thoroughness that is applied. Management has directed that a more standardized approach be developed. The new incident investigative procedures are scheduled to be completed by the end of 2003.

Protocol # 8.05	Program Evaluation: Process Implementation
Protocol Question	Is the process for evaluating IM Program performance being implemented as specified by the program documents?

The purpose of this protocol is to ensure that the program evaluation process is being implemented in accordance with the company's approved guidance/procedures. The inspection should review sufficient records to ensure that:

1. Data collection and analyses have been implemented as described in the operator's program.
2. Trends and/or insights are being identified.
3. Rigorous self assessments and/or management audits of IM Program performance have been completed.
4. Performance problems, positive trends, and improvements have been identified.
5. Specified actions have been implemented or scheduled for implementation.
6. Management reviews of the program evaluation results have been performed routinely to ascertain the effectiveness of risk control decisions.
7. The level of documentation is sufficient to demonstrate satisfactory implementation of the program including adequate documentation of data sources, assumptions, results, and recommended actions.
8. Adequate documentation has been generated to demonstrate that the communications specified in the process document have in fact been prepared and distributed to company personnel responsible for IM Program implementation.

Rule Requirement	§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
	§195.452 (k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

Inspection Summary	

Protocol 8.05 Inspection Results	X	No Issues Identified
		Potential Issues Identified (explain in summary)
		Not Applicable (explain in summary)

Documents Reviewed:

Document Number	Rev.	Date	Document Title
	2	April 28, 2003	Enbridge HCA Management Manual

8.05 Inspection Notes:

ENB indicated that they had employed a contractor to perform a pre OPS inspection of their HMP. The details, and findings, of this pre-inspection were not discussed.

ENBRIDGE™

Operator Qualification (OQ) Plan Audit

Conducted by PHMSA and MNOPS October 20 – 21, 2009

Audit Follow-up Documentation

Submitted by Enbridge

November 12, 2009

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ENBRIDGE™

RECEIVED NOV 1 3 2009

November 12, 2009

Sent by Courier

Mr. Greg Ochs
PHMSA, Office of Pipeline Safety – Central Region
901 Locust Street, Room 462
Kansas City, MO 64106-2641

Re: Enbridge US Operator Qualification (OQ) Program Audit

The purpose of this letter is to provide PHMSA and MNOPS with a DRAFT proposal of preliminary changes made to the Enbridge US OQ program as recommended during the team audit conducted October 20-21, 2009. The Enbridge US OQ Plan covers the following pipeline companies/systems operated by U.S. Enbridge affiliates:

- Vector Pipeline LLC (operator id #: 31356)
- Enbridge Pipelines (Lakehead) L.L.C. (operator id #: 11169)
- Enbridge Pipelines (Toledo) Inc. (operator id #: 31448)
- Enbridge Pipelines (Ozark) L.L.C. (operator id #: 31947)
- CCPS Transportation, LLC (operator id #: 32080)
- Enbridge Pipelines (North Dakota) LLC (operator id #:15774)

Enbridge will make the changes as proposed, following normal internal change management processes.

Draft Proposal of Changes:

Protocol 1.02 Contractor Qualification	• Section 8.2.2 – Updated wording to address site specific AOCs by adding Job Plans and Safe Work Permit references. • Section 8.3 - Removed all ambiguous *'certify'* references and re-phrased sentences to clarify vendor requirements.
Protocol 1.04 Training Requirements	• Appendix F: #17.7 - Contractor OQ Covered Tasks #27.2 - "Other" category removed and API 653 sections clarified. • Appendix F: #17.7 - Contractor OQ Covered Tasks #38.4 - *"Other"* category removed and ASNT Certification sections clarified.
Protocol 2.01 Development of Covered Task List	• Appendix A: #12.1 - Added numbering to Control Center covered task list section (CC1-CC5). • Appendix A: #12.2 - Removed UT task from the Enbridge US Tasks Considered but Deemed not a Covered Task list since UT meets the 4-part criteria test even though it is not currently a covered task being performed by company personnel.
Protocol 2.02 Evaluation Method(s)	• Appendix A #12.4 - OQT Evaluation form #67: General Pipeline Repairs - Tight Fitting Sleeves: Added a test step *"Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.)"*. Added similar language to other pipeline repair methods (#66, #68-72). This change will be reviewed and communicated with the OQ Steering Committee at next meeting. Target Date: 1st Quarter 2010.

Protocol 3.01 Development/Documentation of Areas of Qualification for Individuals Performing Covered Tasks	• Future OQ Awareness Sessions conducted by Enbridge US Compliance department will provide more targeted training around Appendix F, Section #17. • Section 11.0 - Compliance pre-audit reviews will include verification of OQ Contractor Appendix F, Section #17. • ISNetWorld access implementation to include setting up the email alert system to advise personnel in advance when an Enbridge US individual's OQ qualifications are expiring. Target Date: 1^{st}-2^{nd} Quarter 2010.
Protocol 3.02 Covered Task Performed by Non-Qualified Individual	• Section 6.2.3 and Appendix F- #17.1, #17.4, #17.6 - Enbridge 5-day rule clarified as a '*best practice*' rather than a requirement. Language softened in Enbridge US OQ Plan to reduce potential future liability issues. • Section 6.2.4 – Added the zero span of control ratio wording for <u>only</u> contractors performing tapping work on stopples. • Appendix F: #17.7 - Covered Tasks #40.7 and #40.8: Updated the Contractor OQ Covered Task List to reflect the zero span of control ratio (1:0) as referenced in Section 6.2.4.
Protocol 4.02 Evaluation of Individual's Capability to Recognize and React to AOCs	• Section 8.2.2 - Updated wording to address site specific AOCs by adding Job Plans and Safe Work Permit references.
Protocol 5.01 Personnel Performance Monitoring	• Section 3.6 - Updated wording to reflect Enbridge US Project Manager/Designee's responsibility to check that a contractor's records have not been suspended on any assigned OQ covered tasks. • Section 6.3.4 - Updated wording to reflect the suspension communication process and the actual suspension (red flagging) of an individual's record within ISNetWorld. • Section 8.4.4 – Updated wording to reflect Enbridge US Project Manager/Designee's responsibility to check that a contractor's records have not been suspended on any assigned OQ covered tasks. • Appendix F: #17.1 - Added (f) to step #8 in flowchart description.
Protocol 5.02 Reevaluation Interval and Methodology for Determining the Interval	• Section 6.3.7 – Added an exception clause to the *'not to exceed 42 months'* interval statement for NDT. • Appendix A: #12.1 – Enbridge US Employee Covered Task #69 Pipeline Repair: Composite Sleeve - Updated section to include Clock Spring re-qualification requirements (1 year). • Appendix F: #17.7 – Contractor OQ Covered Tasks #40.3 – Updated section to include Clock Spring re-qualification requirements (1 year). • Appendix F: #17.7 – Contractor OQ Covered Tasks #42.1 thru #42.6 - Updated welding sections to include API 1104 wording.
Protocol 7.01 Qualification "Trail" (Maintain Program Records)	• Section 6.3.4 - Updated wording to reflect the suspension communication process and the actual suspension (red flagging) of an individual's record within ISNetWorld.

Protocol 8.01 Management of Changes	• Section 3.8 - Updated to reflect contractor's responsibility to implement and communicate changes made to the Enbridge US OQ Plan. • Section 9.1 - Updated to reflect contractor's responsibility to implement and communicate changes made to the Enbridge US OQ Plan. • Section 9.3 - Updated section to capture examples of critical and non-critical change information given to individuals.

Enbridge Covered Tasks

With regards to Protocol 2.01 and PHMSA's interpretation that all O&MP tasks should be considered OQ covered tasks, Enbridge offers the following interpretation.

The regulation states that "a covered task is an activity, as defined by the operator, that ". . . [meets all conditions of the four part test]":

- Is performed as a requirement of 49 CFR Part 195 or 192
- Is an operations or maintenance task
- Is performed on a pipeline facility
- Affects the operation or integrity of the pipeline facilities

Section 4.0 of Enbridge's Operation Qualification Plan (OQ Plan) defines the process used to determine which operation and maintenance tasks are considered Company covered tasks.

Enbridge has created their OQ covered task list per regulations 195.501 or 192.801 as those tasks that meet the 4-part criteria. This assessment is documented in our OQ Plan under Appendix A: Sections 12.1, 12.2 and 12.3. Additionally, Enbridge completed an analysis of our covered task list against the industry guidelines (API OQC Covered Task list), which also follows the 4-part criteria test, as part of a verification process to check that our OQ cover task list is robust.

The specific activities discussed during the audit were "performing a cold cut" or "installation of a mud plug". As highlighted in Section 12.2 & 12.3, Enbridge has not deemed these activities as covered tasks, as we do not believe they meet all aspects of the 4-part criteria. Enbridge's rationale for these not deemed covered tasks, is that performance of these activities do not affect the operation or integrity of the pipeline. For example, a poor quality cold cut would not affect the operation or integrity of the pipeline, as it is not the final tie-in point. Conversely, the final welding and testing associated with the related maintenance activity have been deemed covered tasks, since they do meet the 4-part criteria, most notably "will affect the operation or integrity of the pipeline".

If you have any questions or concerns regarding the information provided, please contact me anytime. Again, Enbridge thanks both PHMSA and MNOPS for the collaborative opportunity to improve our Operator Qualification program.

Sincerely,

Dave Hoffman
Supervisor, U.S. Compliance

cc: Brad Ardner, MNOPS
Shaun Kavajecz, Manager Compliance
Cynthia Clark, Compliance Qualifications Coordinator

Attach.

ENBRIDGE US

PROTOCOL 1.02 – Contractor Qualification

Vector MILES - 2008

Michigan - 171

Illinois 35

Indiana 68

Total 274

8.0 CONTRACTOR QUALIFICATION GUIDELINES

8.1 Contractor Standards

8.1.1 Contractor Performance Standards

Contractors engaged to perform covered task work on Enbridge US pipeline systems must comply with the Enbridge US OQ Plan.

8.1.2 Contractor Compliance Documentation Standards

Documentation of qualified workers performing covered tasks must be provided to Enbridge US prior to commencing the covered task work, kept current for the duration of the work and individual's OQ records submitted in a timely manner to ISNetWorld, which retains records in accordance to regulatory requirements.

Note: It is the responsibility of the contractor to train contract workers.

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8.2 Contractor Evaluation Criteria/Qualification Documentation

8.2.1 Contractor Evaluation Criteria/Qualification Documentation (Prior to May 15, 2009)

- Contractor documentation that demonstrates qualification of their employees under Subpart G in 49 CFR Part 195 or Subpart N in 49 CFR Part 192 must be submitted for approval prior to the start of covered task work.

- Contractors may satisfy initial/subsequent qualification requirements by one of the following evaluation methods:
  a) Documented evidence of contractor qualification (Covered Tasks and Abnormal Operating Conditions) via observation of performance/simulation or written test pursuant to applicable regulations through an operator approved third-party vendor (see Enbridge US covered task list in ISNetWorld for details); or
  b) Documented by the same method stated herein for Enbridge US employees for special circumstances.

- Companies who contract to supply 24-hour pipeline, gas and terminal operation control services for Enbridge US must provide on line access to a current database containing qualification data for their operators.

8.2.2 Contractor Evaluation Criteria/Qualification Documentation (EFFECTIVE MAY 15, 2009)

Evaluation of a contractor's knowledge, skills and ability (KSAs) to perform a covered task must meet an Enbridge US approved evaluation method (Appendix F: #17.7 Contractor OQ Covered Task List) as follows:

1. Performance test
Contractor must pass a performance test through an accredited Enbridge US approved third-party vendor.

2. Written knowledge-based assessment test
Contractor must pass a written knowledge-based assessment test through an accredited Enbridge US approved third-party vendor.

3. General Abnormal Operating Condition (AOC) test
Contractor must pass a general AOC test through an Enbridge US approved third-party vendor in order to recognize and react to abnormal operating conditions (AOCs) that may occur while performing the identified covered task. In addition, site specific AOCs are addressed by the Job Plan and Safe Work Permits (O&MP Book 2).

- Contractors are to submit all qualifications to ISNetWorld (JS-518 unless otherwise specified) prior to the start of covered task work.

- Management approval is required for any special circumstances where contractors will be subject to the Enbridge US employee evaluation methods.

8.3 Third-Party Vendor Qualification

Third-party vendor qualification options may be considered upon presentation of valid programs. Enbridge US (JS - 518) currently recognizes and accepts only the following third party OQ vendors:

- National Center for Construction, Education and Research (NCCER);
- Enbridge Technology;
- Solar Turbines;
- Operator Qualification & Solutions Group (OQSG);
- NACE;
- EWebOQ;
- T.D. Williamson, Inc. (TDW);
- Midwest Energy Association (MEA).

The Enbridge US covered task list (ISNetWorld bulletin board and Appendix F, Section #17.7) provides details as to the exact evaluation methods that are acceptable for completion of OQ testing. Contractors using third party vendors must submit all required documentation to ISNetWorld in order to meet certification requirements.

Industry certifications (e.g., API 653 and ASNT) may also be used as part of an individual's qualification to perform a covered task, but only for covered tasks indicated on the Contractors Covered Task List (Appendix F, Section #17.7). However, if this is the method used for qualification, the contractor must also be evaluated on AOCs to be qualified to perform this task.

8.3.1 National Center for Construction, Education and Research (NCCER)

Enbridge US accepts a combination of the following NCCER qualifications per Enbridge US covered task list (Appendix F, Section #17.7 for details):

- Performance Verification, and;
- Training Module (Contren Learning Series includes Performance Verification and Written Test), or Written Assessment Testing, and;
- AOC Assessment Test.

Enbridge US requires that contractors meet the vendor's ~~certify their own evaluators/instructors~~ evaluation requirements via an NCCER Accredited Training Sponsor to enable them to qualify their own employees as evaluators/instructors using one of the methods mentioned above.

8.3.2 Enbridge Technology

Contractors using Enbridge Technology OQ material must complete and provide documentation including all of the following parts of each specific Covered Task Training Module:

- Skill Checklist;
- AOC Scenario;
- Final Exam.

Enbridge Technology promotes third party Proctor evaluators. Contractors selecting their own evaluators should be expected to demonstrate to Enbridge Technology's satisfaction (e.g., resumes, training records, etc.) that such evaluators are able to represent the subject matter from a knowledge (theoretical) and skill (practical) perspective.

8.3.3 Solar Turbines

Solar Turbines evaluates individuals using a combination of the following to ensure acceptable evaluation methods:

- Written Exam;
- Oral Exam;
- Observation during Performance On-the-Job;
- Observation during On-the-Job Training;
- Simulations.

Contractors using Solar Turbines OQ material must complete and provide documentation of Solar's Skills Proficiency Evaluation. Solar requires evaluators to be qualified through Veriforce by means of written tests and reference verifications. A Solar Evaluator utilizes a Skills Proficiency Evaluation Checklist to ensure accurate and consistent assessment when performing an oral examination, on-the-job performance observation or on-the-job training observation.

8.3.4 Operator Qualification & Solutions Group (OQSG)

OQSG evaluates individuals using a combination of the acceptable evaluation methods that includes various levels of assessment of KSAs as follows:

- OQ Verify training and knowledge-based assessments in a computer-based format;
- OQSG performance evaluation;
- AOC knowledge-based assessments in a computer-based format.

Enbridge US requires that contractors meet the vendor's ~~certify their evaluators/proctors~~ evaluation requirements via OQSG to enable them to qualify their own employees as evaluators/proctors using the methods specified in ISNetWorld under the Enbridge US covered task list.

8.3.5 NACE

NACE evaluates individuals through intensive 6-day classroom courses using a combination of the acceptable evaluation methods that includes various levels of assessment of KSAs as follows:

- Open Book Written Exam;
- Practical (Hands-on) Exam;
- AOC Exam.

Contractors using NACE must complete and submit required documentation in order to meet NACE's certification requirements.

Enbridge US requires that contractors meet the vendor's ~~certify their own evaluators/proctors~~ evaluation requirements via NACE evaluator training requirements to enable them to qualify their own employees as evaluators/proctors using the NACE methods mentioned above.

8.3.6 EWebOQ

In order to meet acceptable evaluation methods that assess KSAs, Enbridge US will allow the following combination of EWebOQ and NCCER assessments:

- EWebOQ on-line knowledge test;
- NCCER Performance Verifications;
- NCCER AOC test.

Exact testing evaluation requirements are in ISNetWorld under the Enbridge US covered task list.

8.3.7 T.D. Williamson, Inc. (TDW)

TDW evaluates TDW Field Technicians using a combination of the acceptable evaluation methods that includes various levels of assessment of KSAs as follows:

- Written exams;
- Oral exams;
- Observation during: training, simulation, live jobs and field audits.

Master Technicians and Service Center Managers observe Technicians for certification per TDW guidelines. Technical Services personnel observe Master Technicians and International Master Technicians for certification per TDW guidelines.

Note: Evaluation of qualification includes an individual's ability to recognize and react to AOCs specific to the covered task tested.

Additional requirements around AOC are as follows:
- NCCER general AOC test.

8.3.8 Midwest Energy Association (MEA)

MEA evaluates individuals using a combination of the acceptable evaluation methods that includes various levels of assessment of KSAs as follows:

- On-line knowledge test;
- Hands-on performance evaluation.

Note: AOC testing is embedded within the knowledge and performance evaluations.

Enbridge US requires that contractors meet the vendor's ~~certify their own evaluators~~ evaluation requirements via MEA evaluator training requirements to enable them to qualify their own employees as evaluators using the MEA methods mentioned above.

8.4 Contractor Documentation/Work Site Requirements

8.4.1 Internet Compliance Records Management

- Enbridge US uses ISNetWorld Internet Compliance Records Management as the contractor documentation source to identify qualified workers prior to the beginning of work and for the duration of any work that includes covered tasks.
- Contractors, subscribing to ISNetWorld, who propose to provide services to Enbridge US, must grant access to their qualification data by submitting an OQ Report on ISNetWorld updated as personnel changes throughout the job.

8.4.2 Compliance Records Paper Documentation

If timing lags occur where the contractor qualification data is not appearing in ISNetWorld, contractors may submit hard copy qualification data to the Project Manager/Designee at a minimum of seven working days prior to work commencing. If hard copies of qualification records are accepted, the evaluation methods must be compared to the Enbridge US covered task list (Appendix F, Section #17.7) to ensure OQ qualification validity. **Note:** Most problems in this area are due to contractors not submitting an OQ report to the specified Enbridge US Job Site (Appendix F, Section #17.4, Step #5).

The Enbridge US covered task list (located in ISNetWorld) provides details as to the exact evaluation methods that are acceptable for completion of OQ testing. This covered task list is also located in Appendix F, Section #17.7.

8.4.3 Record Retention

Contractor qualification records will be retained within the ISNetWorld system and/or by Enbridge US for five years.

8.4.4 Submission of Contractor Documentation

Contractors must provide the names and the qualification status of all individuals they intend to assign to Enbridge US jobs that include covered tasks at least 2 full working days prior to the start of work. The Covered Task Worker ID form may be used for this purpose (Appendix F, Section #17.5, Examples: A - E).

The following identifying data is required:

- The name(s) of qualified and non qualified individual(s).
- Each covered task specific to the work being performed.
- Dates of satisfactory completion of covered tasks and AOC evaluation(s) via ISNetWorld.

Enbridge US Project Manager/Designee will verify the qualifications of the proposed workers via proper documentation and send a list of names to the Enbridge US job site representative. In addition, the Enbridge US Project Manager/Designee will check to make sure that an individual's records have not been suspended on any OQ covered tasks assigned. **Note:** It is the responsibility

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PROTOCOL 1.04 – Training Requirements

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: PMT (27)				eWebOQ : LQ1102 (LQ: Inspection - Aboveground Storage Tanks) AND NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCFG ()			36 36
			OR NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (27)							36 36 36
			OR NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (27)							36 36 36
			OR NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT1 (27)							36 36 36
			OR NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (27)							36 36 36
			OR NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (27)							36 36 36
			OR NCCER Performance Verifications : PV271 (PV271) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT1 (27)							36 36 36
27.2	Inspection of in-service breakout tanks	1:0	API : 653 (653 Certification) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	API : 653 (653 Certification) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1260 (KNT195-0810 Inspection of Breakout Tanks) AND API : 653 (653 Certification)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND API : 653 (653 Certification)			36 36
			OR API : 653 (653 Certification) AND NCCER Written Assessments: AOCF ()							36 36
			OR API : 653 (653 Certification) AND NCCER Written Assessments: AOCFG ()							36 36

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			AND NCCER Written Assessments: PMT2 (38)							36
			OR NCCER Performance Verifications : PV383 (PV383) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (38)							36 36 36
			OR NCCER Performance Verifications : PV383 (PV383) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (38)							36 36 36
38.4	Perform non-destructive weld test (NDT)	1:0	ASNT : Certification AND NCCER Written Assessments: AOCF ()	ASNT : Certification AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND ASNT : Certification			36 36
			OR ASNT : Certification AND NCCER Written Assessments: AOCFG ()							36 36
			OR ASNT : Certification AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)							36 36
39.0	Backfilling a trench following maintenance	1:1	NCCER Contren Learning Series : 62107-02 (Excavating and Backfilling (CT 17, 39, 32)) AND NCCER Written Assessments: AOCF ()	OQSG - Performance : CT35 (Backfilling a Trench Following Maintenance) AND OQSG - Written : CT35 (Backfilling a trench Following Maintenance) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1266 (KNT195-1402BF Backfilling a Trench Following Maintenance) AND MEA Performance Evaluation : MEA1217 (PEF195-1402BF Backfilling a Trench Following Maintenance	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 106EXCAV (OSHA/DOT - Excavation Safety) AND eWebOQ : LQ300 (LQ: Marking Pipelines - - Temporary and Permanent) AND NCCER Performance Verifications : PV390 (PV390)			36 36 36 36
			OR NCCER Contren Learning Series : 62107-02 (Excavating and Backfilling (CT 17, 39, 32)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	OR NCCER Performance Verifications : PV390 (PV390) AND OQSG - Written : CT35 (Backfilling a trench Following Maintenance) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			OR eWebOQ : 106EXCAV (OSHA/DOT - Excavation Safety) AND eWebOQ : LQ300 (LQ: Marking Pipelines - - Temporary and Permanent) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV390 (PV390)			36 36 36 36
			OR NCCER Contren Learning Series : 62107-02 (Excavating and Backfilling (CT 17, 39, 32)) AND NCCER Written Assessments: AOCFG ()				OR			
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV390 (PV390) AND							

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PROTOCOL 2.01 – Development of Covered Task List

Enbridge US Covered Task #	Enbridge US (In-House) OQ Covered Task Name	Description	Re-Evaluation Frequency (specified in years)	Span of Control Ratio	Training	Initial or Post Incident-Accident Re-Assessment	Subsequent	1) Part of Regulation (192 or 195); 2) Performed on Pipeline Facility; 3) Operations or Maintenance Task; 4) Affects Operation or Integrity of Pipeline.	Part 195	Part 192	For Reference Purposes Only B31Q
					OQSG -OQVerify: CT22 (Inspect valves)	116 - Verbal - OQT - Vector Gas: Mainline DOT Valve Inspection OR OQSG - Written: CT22 (Inspect valves) AND 116 - AOC - OQT - Vector Gas: Mainline DOT Valve Inspection OR OQSG - Written: CT60 (General Abnormal Operating Conditions)	OQSG - Written: CT22 (Inspect valves) AND OQSG - Written: CT60 (General Abnormal Operating Conditions)				
117	Vector Gas: Station Gas Detector Calibration	This task consists of activities related to the testing and calibration of vapor detectors installed on the pipeline system.	3	1:1	417- PBT OQT: Vector Gas: Station Gas Detection Calibration AND/OR OQSG -OQVerify: CT54 (Gas Detection and Alarm System Maintenance and Performance Testing)	117 - Performance - OQT - Vector Gas: Station Gas Detection Calibration AND 117 - Verbal - OQT - Vector Gas: Station Gas Detection Calibration OR OQSG - Written: CT54 (Gas Detection and Alarm System Maintenance and Performance Testing) AND 117 - AOC - OQT - Vector Gas: Station Gas Detection Calibration OR OQSG - Written: CT60 (General Abnormal Operating Conditions)	117 - Performance - OQT - Vector Gas: Station Gas Detection Calibration AND OQSG - Written: CT54 (Gas Detection and Alarm System Maintenance and Performance Testing) AND OQSG - Written: CT60 (General Abnormal Operating Conditions)	Y		192.736	Task 0551 Task 0591
118-149	OPEN FOR FUTURE USE										
CONTROL CENTER OPERATIONS (EDMONTON) - Liquid and Terminal Pipelines											
CC1	Control Center: Monitor and Control Pressures and/or Flows	This task may include activities and procedures performed by the Control Center that are required for safe and prudent operation of the pipeline.	3	1:1	OPSS Training Modules AND	Performance or Simulation OQT - Control Center: Monitor and Control Pressures and/or Flows AND	Performance or Simulation OQT - Control Center: Monitor and Control Pressures and/or Flows AND	Y	195.402; 195.406; 195.408	192.605	Task 1391; Task 1371

Enbridge US Covered Task #	Enbridge US (In-House) OQ Covered Task Name	Description	Re-Evaluation Frequency (specified in years)	Span of Control Ratio	Training	Initial or Post Incident-Accident Re-Assessment	Subsequent	1) Part of Regulation (192 or 195); 2) Performed on Pipeline Facility; 3) Operations or Maintenance Task; 4) Affects Operation or Integrity of Pipeline.	Part 195	Part 192	For Reference Purposes Only B31Q
					On-The-Job Check List: Lotus Notes Terminal Database AND/OR On-The-Job Check List: Lotus Notes Pipeline Entry Level Database	AOC OQT Verbal - Control Center: Monitor and Control Pressures and/or Flows AND AOC OQT Written - Control Center: Monitor and Control Pressures and/or Flows	AOC OQT Verbal - Control Center: Monitor and Control Pressures and/or Flows AND AOC OQT Written - Control Center: Monitor and Control Pressures and/or Flows				
CC2	Control Center: Operation of Remote Valves	The operator will routinely operate remote valves as part of the daily operation of the pipeline system.	3	1:1	OPSS Training Modules AND On-The-Job Check List: Lotus Notes Terminal Database AND/OR On-The-Job Check List: Lotus Notes Pipeline Entry Level Database	Performance or Simulation OQT - Control Center: Operation of Remote Valves AND AOC Verbal OQT - Control Center: Operation of Remote Valves AND AOC OQT Written - Control Center: Operation of Remote Valves	Performance or Simulation OQT - Control Center: Operation of Remote Valves AND AOC Verbal OQT - Control Center: Operation of Remote Valves AND AOC OQT Written - Control Center: Operation of Remote Valves	Y	195.402; 195.406; 195.408	192.605; 192.745	Task 1391; Task 1371
CC3	Control Center: Operation of Remote Pumps	The operator will routinely operate mainline units or booster pumps to facilitate the movement of product through the pipeline system.	3	1:1	OPSS Training Modules AND On-The-Job Check List: Lotus Notes Terminal Database AND/OR On-The-Job Check List: Lotus Notes Pipeline Entry Level Database	Performance or Simulation OQT - Control Center: Operation of Remote AND AOC Verbal OQT - Control Center: Operation of Remote Pumps AND AOC OQT Written - Control Center: Operation of Remote Pumps	Performance or Simulation OQT - Control Center: Operation of Remote AND AOC Verbal OQT - Control Center: Operation of Remote Pumps AND AOC OQT Written - Control Center: Operation of Remote Pumps	Y	195.402; 195.406; 195.408	192.605	Task 1391; Task 1371

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Enbridge US Covered Task #	Enbridge US (In-House) OQ Covered Task Name	Description	Re-Evaluation Frequency (specified in years)	Span of Control Ratio	Training	Initial or Post Incident-Accident Re-Assessment	Subsequent	1) Part of Regulation (192 or 195); 2) Performed on Pipeline Facility; 3) Operations or Maintenance Task; 4) Affects Operation or Integrity of Pipeline.	Part 195	Part 192	For Reference Purposes Only B31Q
CC4	Control Center: Monitor Leak Detection - Computational Pipeline Monitoring (CPM) - (**Liquid Pipelines Only)	The operators will routinely monitor the CPM leak detection system to ensure the systems integrity.	3	1:1	OPSS Training Modules AND On-The-Job Check List: Lotus Notes Terminal Database AND/OR On-The-Job Check List: Lotus Notes Pipeline Entry Level Database	Performance or Simulation OQT - Control Center: Monitor Leak Detection - Computational Pipeline Monitoring (CPM) - (**Liquid Pipelines Only) AND AOC Verbal OQT - Control Center: Monitor Leak Detection - Computational Pipeline Monitoring AND AOC OQT Written - Control Center: Monitor Leak Detection - Computational Pipeline Monitoring	Performance or Simulation OQT - Control Center: Monitor Leak Detection -Computational Pipeline Monitoring (CPM) - (**Liquid Pipelines Only) AND AOC Verbal OQT - Control Center: Monitor Leak Detection -Computational Pipeline Monitoring AND AOC OQT Written - Control Center: Monitor Leak Detection -Computational Pipeline Monitoring	Y	195.444		Task 0241; Task 0261; Task 0271; Task 0281; Task 0291; Task 0221
CC5	Control Center: Monitor Tank Levels	The operator must routinely monitor the tank levels to ensure they are managed within the allowable limits.	3	1:1	OPSS Training Modules AND On-The-Job Check List: Lotus Notes Terminal Database AND/OR On-The-Job Check List: Lotus Notes Pipeline Entry Level Database	Performance or Simulation OQT - Control Center: Monitor Tank Levels AND AOC Verbal OQT - Control Center: Monitor Tank Levels AND AOC OQT Verbal - Control Center: Monitor Tank Levels	Performance or Simulation OQT - Control Center: Monitor Tank Levels AND AOC Verbal OQT - Control Center: Monitor Tank Levels AND AOC OQT Verbal - Control Center: Monitor Tank Levels	Y	195.428		Task 0261
150-159	OPEN FOR FUTURE USE										
CONTROL CENTER OPERATIONS (GATHERING SYSTEMS) Liquid and Terminal Pipelines											
160	Control Center: Monitor and Control Pressures and/or Flows	This task may include activities and procedures performed by the Control Center that are required for safe and prudent operation of the pipeline.	3	1:1	OPSS Training Modules AND Performance-Based-Training Check List	160 - Performance or Simulation OQT - Control Center: Monitor and Control Pressures and/or Flows AND 160 - AOC OQT Verbal - Control Center: Monitor and Control Pressures and/or Flows AND	160 - Performance or Simulation OQT - Control Center: Monitor and Control Pressures and/or Flows AND 160 - AOC OQT Verbal - Control Center: Monitor and Control Pressures and/or Flows AND	Y	195.402; 195.406; 195.408	192.605	Task 1391; Task 1371

SECTION 12.2 | APPENDIX A: TASKS CONSIDERED BUT DEEMED NOT COVERED TASKS

Task/Procedure	Four Part Test: Part of Regulation (192 or 195)	Performed on Pipeline Facility	Operations or Maintenance Task	Affects Operation or Integrity of Pipeline	Comments
GENERAL					
Reporting Accidents	195.50	N	N	N	
Investigation of Accidents/Inspection	195.60	Y/N*	Y	N	*Dependent upon location.
Safety Related Condition Reporting	195.55	N	N	Y	
Paperwork/Record Keeping	195.404; 195.310; 195.310; 195.402(e)(i)	Y/N*	Y	N	*Dependent upon location.
Maximo Work Orders/Trouble Reporting	195.402c1	N	N	N	Maximo is a records system not affecting operations, maintenance or integrity of the line.
Firefighting Equipment/Fire Protection System/Fire Fighting	195.430; 195.432	Y	Y	N*	Fire system maintenance ensures readiness, but does not impact integrity. Fire fighting takes place after integrity has already been compromised.
Emergency Plans	195.403	N	Y	N	
Emergency Training	195.403	N	N	N	
Emergency Evacuation System	195.402c	Y/N	Y	N*	Emergency Response and Evacuation activities take place after integrity has already been compromised.
General Maintenance, checklists and Inspections	N/A	Y/N*	Y	N	*Dependent upon location.
Landowner Visitations	195.440	N	N	N	Visits to homes are not on the pipeline facility.
Public Education/Awareness	195.440	N	Y	N	
Site Safety Officer Role	N/A	N	N	N	
Contractor Supervision	N/A	N	N	N	
Instructional Modules	N/A	N	Y/N*	N	*Dependent upon Instructional Module.
Building and Grounds	N/A	N	Y	N	
Parafin Recyling	N/A	N	Y	N	
Pig Tracking	N/A	Y	Y	N	
TANK MAINTENANCE					
Seal Tip Changing	195.432	Y	Y	N	
Secondary Seal Replacement	195.432	Y	Y	N	
Out of Service Tank (Binded off and permanently taken out of service).	195.432	Y	Y	N	**Note: Tanks taken Out of Service for maintenance/repair purposes are OQ covered tasks.**
Seal Tank Flushing	N/A	Y	Y	N	
PIPELINE MAINTENANCE (PLM)					
Cold Cut	N/A	Y	Y	N	
Vapor (mud) plug	N/A	Y	Y	N	
Flange Tightening	N/A	Y	Y	Y	
Rigging	N/A	N	Y	N	
~~Ultrasonic~~	~~N/A~~	~~Y~~	~~Y~~	~~N~~	
Small Equipment	N/A	N	Y	N	

ENBRIDGE US

PROTOCOL 2.02 - Evaluation Method(s)

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #67 Pipeline Repair: Tight Fitting Sleeve
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#67	OQT PIPELINE REPAIR: TIGHT FITTING SLEEVE
	Sleeving preparation:
☐	Refer to Excavation Procedure (See OQT #56 - Damage Prevention During Excavation Activities).
☐	Refer to Defect or Corrosion Procedures as necessary.
☐	Measure the induced AC potential.
☐	Prepare surface by wire buffing or abrasive blasting as required.
☐	Fill dents or voids as needed.
☐	Ensure proper ultrasonic testing has been done for weld ends.
☐	Refer to authorization procedure for direct welding on line.
☐	Post fire watch.
	Application of tight fitting sleeve:
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Prepare and fit bottom and top of tight fitting sleeve to pipeline:
	• Install back-up strips under longitudinal welds.
	• Rig bottom half to lifting equipment.
	• Apply chains around bottom half of sleeve and pipe.
	• Swing bottom half into position.
	• Jack bottom half of sleeve tight to pipeline.
	• Measure distance for top half of sleeve.
	• Cut to fit.
	• Skid up bottom half of sleeve.
	• Remove chains.
	• Rig top half to lifting equipment.
	• Line up with lower half.
	• Place jack on top of sleeve using jacking caps.
	• Apply chains around both halves and jack.
☐	Weld first pass on side seam in all accessible areas.

☐	Remove jacks and chains.
☐	Complete welding side seams.
☐	Weld ends to pipeline.
☐	Request magnetic particle test after 12 hours.
☐	Refer to Pipe and Valve Coating Procedure (See OQT #19 - Pipe and Valve Coating).
☐	Support with concrete bench or sacrete pyramid if necessary.
☐	Tamp and backfill (See OQT #57 - Backfilling Activities).
☐	Restore right-of-way.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-03-20 Installing Pressure-Containment Sleeves

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 67.1	Sleeve must be applied over extremely high weld.	Grind some of the weld out to lessen the gap on the tight fitting sleeve.
		Cut back the length of the tight fitting sleeve to go up to the weld and install another tight fitting sleeve on the other side of the weld. Then install an oversleeve that will go over the weld on the pipe.
		Have the welder analyze the condition of the weld and check the area for corrosion which may affect the strength of the weld. For example, where there is extreme corrosion in the weld area, grinding would not be an option.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.

		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, **AND;**
2. Verbal Review OR OQSG Written Test, **AND;**
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	**Pass Date (Must be in mm/dd/yyyy format)**	**Re-Train**
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	**Other Comments**

Need to test "one" task specific AOC and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	**Pass**	**Pass Date (Must be in mm/dd/yyyy format)**	**Re-Train**
☐ **AOC #67.1**	☐		☐

Need to test "two" general AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ AOC #200.1	☐		☐	☐ AOC #200.6	☐		☐
☐ AOC #200.2	☐		☐	☐ AOC #200.7	☐		☐
☐ AOC #200.3	☐		☐	☐ AOC #200.8	☐		☐
☐ AOC #200.4	☐		☐	☐ AOC #200.9	☐		☐
☐ AOC #200.5	☐		☐	☐ AOC #200.10	☐		☐

-OR-

General AOC Testing
☐ **OQSG Written: CT 60 (General Abnormal Operating Condition**

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	Date
Signature:	
Employee (Print Name):	**Date**
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 – Formatting Changes
3.0	11/06/07	11/06/07	OQ Administrator	MOC #49 – Formatting Changes
4.0	08/07/08	08/07/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	10/21/08	11/19/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #66 Pipeline Repair: Oversleeve
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#66	OQT PIPELINE REPAIR - OVERSLEEVE
	Sleeving preparation:
☐	Refer to Excavation Procedure (See OQT #56 - Damage Prevention During Excavation Activities).
☐	Refer to Defect or Corrosion Procedures as necessary.
☐	Measure the induced AC potential.
☐	Prepare surface by wire buffing or abrasive blasting as required.
☐	Fill dents or voids as needed.
☐	Ensure proper ultrasonic testing has been done for weld ends.
☐	Refer to authorization procedure for direct welding on line.
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Prepare and fit collars to pipeline using jacks and chains:
	• Cut collars to a minimum width of 4".
	• Apply back-up strips.
	• Fit collar to pipeline by cutting or grinding.
	• Place collar on line so inside welds are 4" less than desired length of oversleeve when using 4" collars.
	• Chain and jack in place to proper fit.
☐	Post fire watch.
☐	Preheat as needed.
☐	Tack side seam of collars.
☐	Remove chains and jacks from collars.
☐	Weld side seam of collars.
	Application of oversleeve:
☐	Prepare and fit bottom and top halves of oversleeve to collars.
☐	Install back-up strips under longitudinal welds.
☐	Rig bottom half to lifting equipment.
☐	Set on to centers of pre-welded collars.
☐	Apply chains around bottom half of sleeve and pipe.

☐	Swing bottom half into position.
☐	Install back-up strips under longitudinal welds.
☐	Rig bottom half to lifting equipment.
☐	Set on to centers of pre-welded collars.
☐	Apply chains around bottom half of sleeve and pipe.
☐	Jack bottom half of sleeve tight to collars.
☐	Measure distance for top half of sleeve.
☐	Cut to fit.
☐	Skid up bottom half of sleeve.
☐	Remove chains.
☐	Rig top half to lifting equipment.
☐	Set top half of sleeve on collars.
☐	Line up with lower half.
☐	Place jack on top of sleeve using jacking caps.
☐	Apply chains around both halves and jack.
☐	Test pipe with Degauss meter (optional).
☐	Demagnetize pipe if necessary.
☐	Preheat as needed.
☐	Tack side seam of oversleeve in accessible areas.
☐	Remove jacks and chains.
☐	Weld side seams of oversleeve
☐	Weld oversleeve ends to center of collars.
☐	Weld ends of collars to pipeline.
☐	Request magnetic particle test of oversleeve after 12 hours.
☐	Refer to Pipe and Valve Coating Procedure (See OQT #19 - Pipe and Valve Coating).
☐	Support with concrete bench or sacrete pyramid if necessary.
☐	Tamp and backfill (See OQT #57 - Backfilling Activities).
☐	Restore right-of-way.
☐	Fill out a permanent repair report.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-02-06 Split Sleeves
	• O&MP: Book 3: 06-03-20 Installing Pressure Containment Sleeves

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 66.1	There is excessive end gap on the sleeve.	Refit sleeve.
		Add more chains and jacks.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, **AND;**
2. Verbal Review OR OQSG Written Test, **AND;**
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	Other Comments

Need to test "one" task specific AOC and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **AOC #66.1**	☐		☐

Need to test "two" general AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ **AOC #200.1**	☐		☐	☐ **AOC #200.6**	☐		☐
☐ **AOC #200.2**	☐		☐	☐ **AOC #200.7**	☐		☐
☐ **AOC #200.3**	☐		☐	☐ **AOC #200.8**	☐		☐
☐ **AOC #200.4**	☐		☐	☐ **AOC #200.9**	☐		☐
☐ **AOC #200.5**	☐		☐	☐ **AOC #200.10**	☐		☐

-OR-

General AOC Testing
☐ **OQSG Written: CT 60 (General Abnormal Operating Condition**

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	**Date**
Signature:	
Employee (Print Name):	**Date**
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 –Formatting Changes
3.0	11/06/07	11/06/07	OQ Administrator	MOC#49 – Formatting Changes
4.0	08/07/08	08/07/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	10/21/08	11/19/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #68 **Pipeline Repair: Plidco Split Repair**
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#68	OQT PIPELINE REPAIR: PLIDCO SPLIT REPAIR
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Buff ends and side seams.
☐	Clean and check sealing elements.
☐	Perform or request ultrasound.
☐	File off seam and clean pipe where sealing element fits.
☐	Center and install bottom and top of Plidco on pipe.
☐	Tighten stud bolts on both sides of Plidco using proper sequence.
☐	Request line start up at reduced pressure prior to welding.
☐	Fillet weld ends.
☐	Fillet weld side seams.
☐	Request return to operating pressure.
☐	Fillet weld studs with nuts in place.
☐	Request 12 hour mag particle test.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-02-06 Split Sleeves
	• O&MP: Book 3: 06-03-12 Plidco Split Plus Sleeves

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 68.1	A newly installed Plidco leaks.	Check the alignment and the Hi-Lo on the side seam. If it is not even, loosen and retighten or tight wide side.
		Remove Plidco.
		Check the rubber seals.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, **AND;**
2. Verbal Review OR OQSG Written Test, **AND;**
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	Other Comments

Need to test "one" task specific AOC and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **AOC #68.1**	☐		☐

Need to test "two" general AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ **AOC #200.1**	☐		☐	☐ **AOC #200.6**	☐		☐
☐ **AOC #200.2**	☐		☐	☐ **AOC #200.7**	☐		☐
☐ **AOC #200.3**	☐		☐	☐ **AOC #200.8**	☐		☐
☐ **AOC #200.4**	☐		☐	☐ **AOC #200.9**	☐		☐
☐ **AOC #200.5**	☐		☐	☐ **AOC #200.10**	☐		☐

-OR-

General AOC Testing
☐ **OQSG Written: CT 60 (General Abnormal Operating Condition**

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	**Date**
Signature:	
Employee (Print Name):	**Date**
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 – Formatting Changes
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4.0	08/07/08	08/07/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	10/21/08	11/19/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #69 **Pipeline Repair: Composite Sleeve**
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#69	OQT PIPELINE REPAIR: COMPOSITE SLEEVE
☐	Refer to excavation procedure.
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Prepare surface by wire buffing or sand blasting.
☐	Remove excess moisture from pipe with acetone, if needed.
☐	Scribe pipe by using mylar wrap or 3 wraps of Clock Spring.
☐	Remove the unprinted release film of starter pad.
☐	Center and square the starter pad and press onto the pipe surface.
☐	Apply filler to defects, pipe seam and edge of starter pad.
☐	Apply adhesive evenly over the pipe section that will immediately be covered with Clock Spring including starter pad (applying in one direction only over the starter pad).
☐	Remove printed side of release film from starter pad.
☐	Pull the lead edge beneath the pipe to cover the starter pad.
☐	Align the circumferential edge of the Clock Spring with the scribed area.
☐	Tap with hammer Clock Spring lead edge onto starter pad to ensure proper adhesion.
☐	Check expiration dates of adhesive/filler materials.
☐	Apply adhesive while supporting the coiled Clock Spring atop the pipe (on larger diameter pipe, use spool feeder support for the Clock Spring).
☐	Wrap the Clock Spring around the pipe on the adhesive coated area.
☐	Continue applying adhesive and wrapping until Clock Spring is completely wrapped.
☐	Install locktight pad on Clock Spring.
☐	Tap the locktight end of the cinch strap onto the locktight pad that is mounted on the Clock Spring.
☐	Cinch to Clock Spring onto the pipe using the cinch strap hook.
☐	Tap Clock Spring edges with wooden block for final alignment.
☐	Tape the Clock Spring into position while maintaining pressure on the tensioning bar.
☐	Seal by hand pressure rubber sealant along outside edges.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-02-02 Defect Evaluation and Repair Methods

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 69.1	Corrosion is found on the outside of a bend. It is determined that a clockspring needs to be installed on the corrosion.	Prepare corrosion and pipe as would be done for normal straight pipe installation.
		Use 6" clockspring when installing outer wrap.
		Butt edges of clockspring tight to each other on inside of bend.
		Continue procedure until clockspring covers corrosion and passes recommended length.
		Observe gaps on outside of bend in the clockspring which lend to the effectiveness of the repair (Burst tests have shown that pipe outside the repair zone burst at twice the maximum allowable pressure).
☐ 69.2	A dent is found on the pipe. It is determined that a clockspring needs to be applied on the area with a dent.	Repair dent or gouge per the OM&P before installing the clockspring (which can only be applied to repaired dents).
		Cover the entire dent with the clockspring.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).

		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, **AND;**
2. Verbal Review OR OQSG Written Test, **AND;**
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	Other Comments

Need to test "two" task specific AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **AOC #69.1**	☐		☐
☐ **AOC #69.2**	☐		☐

Need to test "one" general AOC and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ **AOC #200.1**	☐		☐	☐ **AOC #200.6**	☐		☐
☐ **AOC #200.2**	☐		☐	☐ **AOC #200.7**	☐		☐
☐ **AOC #200.3**	☐		☐	☐ **AOC #200.8**	☐		☐
☐ **AOC #200.4**	☐		☐	☐ **AOC #200.9**	☐		☐
☐ **AOC #200.5**	☐		☐	☐ **AOC #200.10**	☐		☐

-OR-

General AOC Testing
☐ **OQSG Written: CT 60 (General Abnormal Operating Condition**

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	**Date**
Signature:	
Employee (Print Name):	**Date**
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 – Formatting Changes.
3.0	11/06/07	11/06/07	OQ Administrator	MOC #49 – Formatting Changes
4.0	08/07/08	08/07/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	10/21/08	11/19/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #71 Pipeline Repair: Stopple
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#71	OQT PIPELINE REPAIR: A) STOPPLE, B) STOPPLE TIE-IN
	Stopple Preparation:
☐	Read chart or blue prints.
☐	Refer to Excavation Procedure.
☐	Measure the induced AC potential.
☐	Determine proper location of stopple fittings.
☐	Refer to Authorization Procedure for direct welding on line.
☐	Ensure proper ultrasonic testing where fillet welds are to be made.
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Prepare fitting:
	• Buff or grind paint off bevels.
	• Check segments for operation and amount of turns.
	• Label amount of turns on flange.
	• Check counter bore on stopple fitting.
☐	Preheat as needed.
☐	Fit stopple fitting on line (see sleeving procedure).
☐	Preheat as needed.
☐	Weld side seams.
☐	Request pressure reduction.
☐	Preheat as needed.
☐	Stand fire watch.
☐	Fillet weld ends on stopple fittings.
☐	Weld on 2" equalization fittings when ends are welded (minimum of 18" from fitting-could also be used for venting behind vapor plugs).
☐	Request return to operating pressure.
☐	Request 12 hour mag particle test.
☐	Support stopple fitting.
☐	Install gasket on clean surface on stopple fitting.

SECTION 12.4 | OQT EVALUATION: #71 – Pipeline Repair: Stopple

☐	Take proper measurements required to make tap and plug.
☐	Check bolts, faces and sandwich valve.
☐	Rig sandwich valves for installation.
☐	Install sandwich valves.
☐	Quarter and tighten bolts on sandwich valves (refer to flange tightening procedure).
	Pipeline Repair: Stopple - Tie-In
☐	Install bonding cables.
☐	Install 2" equalization line, hydraulic hoses, valves and gauges.
☐	Open 12" bypass valves (if bypass installed).
☐	Fill bypass and stopple plugging machines while purging air.
☐	Equalize pressure.
☐	Attach hydraulic hoses to sandwich valve.
☐	Open sandwich valve.
☐	Request and verify line shutdown.
☐	Verify w/gauges pressure is equalized on both sides of stopple plugging machines.
☐	Run down sealing elements (downstream stopple first) lock bar lock.
☐	Close 2".
☐	Remove equalization hose.
☐	Bleed off pressure between stopple plugging machine.
☐	Check for stopple sealant leak.
☐	Request Line start up at reduced rate if bypass is used.
☐	Start continuous monitoring with gas detector.
☐	Drain up section between plugging machines (refer to O&MP Book 3: 06-03-03).
☐	Refer to Cold Cut Procedures.
☐	Remove old pipe by rolling out sideways when possible.
☐	Install vapor plug careful not to block vents behind vapor plugs (refer to vapor plug procedures).
☐	Recheck vapor plugs for vapors with gas detector.
☐	Bevel.
☐	Place fabrication.
☐	Line up fittings for weld.
☐	Recheck for vapors with gas detector.
☐	Install fabrication.
	Completion:
☐	Reattach 2" equalization hose.
☐	Fill properly vented line until equalized.
☐	Check for leaks around fittings and welds.
☐	Request line shutdown.
☐	Unlock bar lock.
☐	Verify w/gauges pressure is equalized on both sides of stopple plugging machine.
☐	Retract stopple sealing elements upstream stopple first.
☐	Attach hoses on sandwich valve.
☐	Close sandwich valve.
☐	Close down 2" equalization line on main line.
☐	Request line start up.

☐	Bleed off pressure from bypass and stopple plugging machines.
☐	Check for leaks around flanges.
☐	Remove hoses from stopple plugging machine in proper order.
	• Drain up bypass and stopple plugging machines (refer to O&MP Book 3, 06-03-03).
☐	Disassemble bypass.
☐	Blind off 12" bypass on stopple plugging machine.
☐	Disconnect 2" equalization lines.
☐	Remove stopple plugging machines.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-03-07 Installing Stopples

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 71.1	A stopple tee installed on the pipe has a gap too large on the end welds.	Check fittings to ensure there is a matching set.
		Check for pipe defects. For instance, tee may have to be relocated if pipe is bent out of round.
☐ 71.2	A malfunction occurs in the equipment.	Access damage.
		Repair, if possible.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).

			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, AND;
2. Verbal Review OR OQSG Written Test, AND;
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	Other Comments

Need to test "two" task specific AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ AOC #71.1	☐		☐
☐ AOC #71.2	☐		☐

Need to test "one" general AOC and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ AOC #200.1	☐		☐	☐ AOC #200.6	☐		☐
☐ AOC #200.2	☐		☐	☐ AOC #200.7	☐		☐
☐ AOC #200.3	☐		☐	☐ AOC #200.8	☐		☐
☐ AOC #200.4	☐		☐	☐ AOC #200.9	☐		☐
☐ AOC #200.5	☐		☐	☐ AOC #200.10	☐		☐

-OR-

General AOC Testing
☐ OQSG Written: CT 60 (General Abnormal Operating Condition

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	Date
Signature:	
Employee (Print Name):	Date
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 - Formatting Changes
3.0	11/06/07	11/06/07	OQ Administrator	MOC #49 – Formatting Changes
4.0	08/07/08	08/07/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	11/21/08	11/21/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #72 Pipeline Repair: Tapping
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#72	OQT PIPELINE REPAIR: TAPPING
	TDW 2" 101:
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Perform ultrasound where 2" TDW will be welded.
☐	Weld TDW fitting.
☐	Request 12 hour magnetic particle test.
☐	Install and fully open 2" full bore valve (do not over tighten).
☐	Take proper measurements.
☐	Set up T-101 tapping machine:
	• Install cutting bit, TDW nipple and bleeder valve.
☐	Attach T-101 to 2" valve.
☐	Extend boring bar to pipe verifying measurement.
☐	Adjust clutch.
☐	Open bleeder valve.
☐	Rotate boring bar until oil fills and equalizes.
☐	Close bleeder valve.
☐	Complete tap.
☐	Check measurements.
☐	Ensure complete tap by running boring bar 1-2" down after tap.
☐	Retract boring bar to zero.
☐	Close 2" valve.
☐	Bleed pressure.
☐	Remove T-101 tapping machine.
☐	Attach proper fittings.
	1200 TAPPING:
☐	Prepare tapping machine:
	• Select proper sized cutter, pilot bit and cutter holder.

☐	Take proper measurements required to make tap and plug.
☐	Check bolts, faces and sandwich valve.
☐	Rig sandwich valves for installation.
☐	Install sandwich valves.
☐	Quarter and tighten bolts on sandwich valves (refer to flange tightening procedure).
	Pipeline Repair: Stopple - Tie-In
☐	Install bonding cables.
☐	Install 2" equalization line, hydraulic hoses, valves and gauges.
☐	Open 12" bypass valves (if bypass installed).
☐	Fill bypass and stopple plugging machines while purging air.
☐	Equalize pressure.
☐	Attach hydraulic hoses to sandwich valve.
☐	Open sandwich valve.
☐	Request and verify line shutdown.
☐	Verify w/gauges pressure is equalized on both sides of stopple plugging machines.
☐	Run down sealing elements (downstream stopple first) lock bar lock.
☐	Close 2".
☐	Remove equalization hose.
☐	Bleed off pressure between stopple plugging machine.
☐	Check for stopple sealant leak.
☐	Request Line start up at reduced rate if bypass is used.
☐	Start continuous monitoring with gas detector.
☐	Drain up section between plugging machines (refer to O&MP Book 3: 06-03-03).
☐	Refer to Cold Cut Procedures.
☐	Remove old pipe by rolling out sideways when possible.
☐	Install vapor plug careful not to block vents behind vapor plugs (refer to vapor plug procedures).
☐	Recheck vapor plugs for vapors with gas detector.
☐	Bevel.
☐	Place fabrication.
☐	Line up fittings for weld.
☐	Recheck for vapors with gas detector.
☐	Install fabrication.
	Completion:
☐	Reattach 2" equalization hose.
☐	Fill properly vented line until equalized.
☐	Check for leaks around fittings and welds.
☐	Request line shutdown.
☐	Unlock bar lock.
☐	Verify w/gauges pressure is equalized on both sides of stopple plugging machine.
☐	Retract stopple sealing elements upstream stopple first.
☐	Attach hoses on sandwich valve.
☐	Close sandwich valve.
☐	Close down 2" equalization line on main line.
☐	Request line start up.

☐	Bleed off pressure from bypass and stopple plugging machines.
☐	Check for leaks around flanges.
☐	Remove hoses from stopple plugging machine in proper order.
	• Drain up bypass and stopple plugging machines (refer to O&MP Book 3, 06-03-03).
☐	Disassemble bypass.
☐	Blind off 12" bypass on stopple plugging machine.
☐	Disconnect 2" equalization lines.
☐	Remove stopple plugging machines.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-03-07 Installing Stopples

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 71.1	A stopple tee installed on the pipe has a gap too large on the end welds.	Check fittings to ensure there is a matching set.
		Check for pipe defects. For instance, tee may have to be relocated if pipe is bent out of round.
☐ 71.2	A malfunction occurs in the equipment.	Access damage.
		Repair, if possible.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).

			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.
☐	200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
			Isolate Area.
			Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, AND;
2. Verbal Review OR OQSG Written Test, AND;
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	**Other Comments**

Need to test "two" task specific AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ AOC #71.1	☐		☐
☐ AOC #71.2	☐		☐

Need to test "one" general AOC and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ AOC #200.1	☐		☐	☐ AOC #200.6	☐		☐
☐ AOC #200.2	☐		☐	☐ AOC #200.7	☐		☐
☐ AOC #200.3	☐		☐	☐ AOC #200.8	☐		☐
☐ AOC #200.4	☐		☐	☐ AOC #200.9	☐		☐
☐ AOC #200.5	☐		☐	☐ AOC #200.10	☐		☐

-OR-

General AOC Testing
☐ OQSG Written: CT 60 (General Abnormal Operating Condition

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	Date
Signature:	
Employee (Print Name):	**Date**
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 - Formatting Changes
3.0	11/06/07	11/06/07	OQ Administrator	MOC #49 – Formatting Changes
4.0	08/07/08	08/07/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	11/21/08	11/21/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

Enbridge US Employee - Operator Qualifications

Employee Name:	HR Employee ID #:	Covered Task: OQT #72 Pipeline Repair: Tapping
Date:	OQ Evaluator:	Location:

A. REASON FOR EVALUATION:

Selection (Check One):
☐ Initial/Subsequent Evaluation
☐ OQ Post Incident/Accident Re-assessment Review (See Appendix D-#15.2)

B. PERFORMANCE OR SIMULATION EVALUATION:

Areas marked 'N/A' should only be applied when the test step will never be performed by the individual in their current job status or if it is a test step that is never done in that specific region/area. Any other reasons for marking areas as 'N/A' need General Manager approval in order for the individual's qualification to be considered valid.

#72	OQT PIPELINE REPAIR: TAPPING
	TDW 2" 101:
☐	Check condition of fitting and components (e.g., Check quality of seals, machine surfaces, threads are not marred, etc.).
☐	Perform ultrasound where 2" TDW will be welded.
☐	Weld TDW fitting.
☐	Request 12 hour magnetic particle test.
☐	Install and fully open 2" full bore valve (do not over tighten).
☐	Take proper measurements.
☐	Set up T-101 tapping machine:
	• Install cutting bit, TDW nipple and bleeder valve.
☐	Attach T-101 to 2" valve.
☐	Extend boring bar to pipe verifying measurement.
☐	Adjust clutch.
☐	Open bleeder valve.
☐	Rotate boring bar until oil fills and equalizes.
☐	Close bleeder valve.
☐	Complete tap.
☐	Check measurements.
☐	Ensure complete tap by running boring bar 1-2" down after tap.
☐	Retract boring bar to zero.
☐	Close 2" valve.
☐	Bleed pressure.
☐	Remove T-101 tapping machine.
☐	Attach proper fittings.
	1200 TAPPING:
☐	Prepare tapping machine:
	• Select proper sized cutter, pilot bit and cutter holder.

	• Install proper sized bell adapter.
	• Change pilot bit nylon insert.
	• Assemble cutter and pilot bit.
	• Check bolts on drive ring.
	• Install and center cutter assembly on tapping machine.
☐	Prepare 101 to tap 2" (to equalize pressure).
☐	Install and tighten 2" valve using Teflon ensuring cross- threading does not occur (do not over tighten).
☐	Tap 2" (manual or air) (Refer to TDW 101 manual).
	WARNING: DO NOT TIGHTEN UNDER PRESSURE.
☐	Install gasket on sandwich valve.
☐	Check for operation and alignment by opening and closing sandwich valve.
☐	Measure to insure complete opening.
☐	Install tapping machine and catwalk.
☐	Quarter and tighten bolts on tapping machine.
☐	Verify product in Line with Control Center.
☐	Prepare to tap:
	• Hoses;
	• Gauges;
	• Bleed off valves;
	• Crank.
☐	Open sandwich valve.
☐	Fill tapping machine and fitting to line pressure while purging air.
☐	Close 2" valves (optional).
☐	Run tapping machine down 5" to increase pressure and test for leaks (optional).
☐	Bleed pressure by opening 2" equalization valves.
☐	Tap to predetermined distance.
☐	Run tapping machine back up.
☐	Close sandwich valve and 2" equalization valve.
☐	Bleed off and drain up (refer to O&MP Book 3: 06-03-03).
☐	Remove tapping machine.
☐	Install new gasket on sandwich valve.
	• Attach sealing element on the plugging head.
	• Grease sealing element liberally before retracting into stopple plugging machine.
	• Check measurements.
☐	Install stopple plugging machine.
☐	Quarter and tighten bolts on stopple plugging machine.
☐	Fabricate bypass to specifications if required.
☐	Install 12" bypass valve, line and gaskets if required.
	TAPPING – North Dakota SPECIFIC:
☐	Inspect tapping machine and materials for:
	• Proper operation;
	• Proper bit for required opening;
	• Fittings and valve of proper class rating for installation;
	• Fitting to be tapped through in good condition.

☐	Verify that weld on above mentioned fitting has not been NDT'd.
☐	Notify Control Center that tap will be made.
☐	Install tapping machine:
	• Install valve and fitting to be tapped through;
	• Secure required sized bit in tapping machine;
	• Retract bit into tapping machine and install tapping machine onto valve;
	• Verify the distance of travel needed to complete tap.
☐	Begin tapping process:
	• Close bleeder valve on tapping machine;
	• Open valve to be tapped through;
	• Hand turn tapping machine until touching surface to be tapped;
	• Begin tapping process.
☐	Completion of tap (tap complete when resistance to bit ceases and projected travel distance is obtained):
	• Hand turn tapping machine to quickly retract bit through valve and into tapping machine;
	• Close tapping valve;
	• Relieve pressure on tapping machine through bleeder valve draining liquid into container;
	• Remove tapping machine and plug tapping valve if no further work is to take place;
	• Notify Control Center of completion;
	• Remove tapping bit and coupon;
	• Inspect bit and tapping machine;
	• Clean equipment and store.
	CROSS REFERENCES:
	• O&MP: Book 3: 06-03-18 Performing Hot Tapping
	• Gathering O&MP: 11.10 Hot Tapping

C. ABNORMAL OPERATING CONDITION (AOC) EVALUATION:

Please check appropriate boxes (indicating "Satisfactory" performance) when the individual can properly describe how to recognize and respond to the tested AOCs below.

TASK SPECIFIC AOCs:

AOC #	Problem	Response
☐ 72.1	Oil starts coming out of top of tapping machine.	Check and tighten packing.
		Open bleeder, retract machine and close valve.
☐ 72.2	While tapping a 2" TDW, the weld cracks.	Call Control Center to shut down line.
		Notify appropriate personnel.
		Repair.
☐ 72.3	While tapping with a 1200, the machine starts to vibrate.	Start cutting at a slower speed until the pilot bit has a good start. If necessary, adjust the speed.
		Check for cutting tooth damage or dull teeth.
		Slow down as it may be cutting through a weld.
☐ 72.4	After tapping, the sandwich valve is closed but will not seal.	Check internal bypass and 2" equalization valve.
		Open and close sandwich valve.
		Drain pipe if necessary.
		Remove tapping machine.

		Repair or replace tapping machine.
☐ 72.5	The bit on the end of the tapping machine will not penetrate through the pipe after continued drilling.	Retract the bit back into the tapping machine.
		Close the valve that is being tapped through.
		Open the bleed off to ensure there is no pressure on the tapping machine.
		Remove the tapping machine from the valve.
		Inspect the bit for damage.
		If the bit was found to be damaged, replace with a new bit.
		Proceed with the tapping procedure.
☐ 72.6	Not able to get the hot tap machine to do a cut on the pipe.	Back the hot tap machine out past the valve.
		Close the valve.
		Bleed off the hot tap machine.
		Take machine off the valve.
		Check to make sure the bit is OK.
		Double check to make sure there was enough travel on the hot tap machine to do the job.
☐ 72.7	Unable to bleed off pressure on tapping machine for removal.	Check to see if the valve is closed, or operate the valve a couple times.
		If unsuccessful, plug the bleeder valve on the tapping machine.
		Proceed with plans to isolate the manifold in this area to replace valve.

GENERAL AOCs:

AOC #	Problem	Response
☐ 200.1	There is an unexpected hydrocarbon encounter (e.g., unauthorized release, vapors, hazardous atmosphere, and contamination).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.2	There is an unexplained pressure deviation (e.g., increase, decrease, high, low, absent).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.3	There is an activation of a safety device (e.g., pressure relief, emergency shut downs, high pressure shut downs, case pressure shut downs, high temperature shut downs, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.4	There is an unexplained flow rate deviation (e.g., high flow, low flow, no flow).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.5	There is an unexplained status change (e.g., unit start up, unit shut down, valve open, valve close, gravity change, tank level, temperature, flash, haze, S&W, co-mingling of product, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.6	There is a fire/explosion.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.7	There is an interruption or failure of communications/control system/power.	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.

		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.8	There is pipeline system damage (e.g., line hit, lightning strikes, tornado, flood, earthquake, etc.).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.9	There is an abnormal facility condition (e.g., exposed pipe, low cathodic protection levels, missing line markers, frayed wires, line crossing, atmospheric corrosion, pipeline support, exposed river crossing).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.
☐ 200.10	Component failure or malfunctioning component (e.g., field and SCADA components including meter failure).	Stop work immediately and notify appropriate personnel of situation (e.g., Control Center, Supervisor, etc.).
		Isolate Area.
		Follow appropriate regional Emergency Response protocols, if needed.

When new AOCs are created, the Supervisor/OQ Evaluator needs to propose the new AOC to the OQ Steering Committee or OQ Administrator. The following detailed AOC information must be documented and submitted for new AOC validation:

Other (Provide AOC Title):
☐ AOC Description:
☐ AOC Recognition:
☐ AOC Reaction:

D. OVERALL EVALUATION RESULTS:

The following must be completed for any OQT Initial/Subsequent testing:

1. Performance OR Simulation Testing, **AND;**
2. Verbal Review OR OQSG Written Test, **AND;**
3. Abnormal Operating Condition Testing.

PASS - This individual has successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan.

RE-TRAIN - This individual has NOT successfully demonstrated the knowledge, skills and ability required by the Enbridge US OQ Plan. A retest will be scheduled and completed by the individual named above. Remedial training should be given before the next evaluation.

	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ **Performance Observation OR**	☐		☐
☐ **Simulation**	☐		☐
☐ **Verbal Review OR**	☐		☐
☐ **OQSG Written: CT36 (Performing General Pipeline Repair Activities)**			

Location Site:	Other Comments

Need to test "two" task specific AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

Task Specific AOC Testing	Pass	Pass Date (Must be in mm/dd/yyyy format)	Re-Train
☐ AOC #72.1	☐		☐
☐ AOC #72.2	☐		☐
☐ AOC #72.3	☐		☐
☐ AOC #72.4	☐		☐
☐ AOC #72.5	☐		☐
☐ AOC #72.6	☐		☐
☐ AOC #72.7	☐		☐

Need to test "one" general AOCs and check the box when the individual is able to verbally discuss how to "Recognize" and "React" to the AOC tested:

General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train	General AOC Testing	Pass	Pass Date (mm/dd/yyyy)	Re-Train
☐ AOC #200.1	☐		☐	☐ AOC #200.6	☐		☐
☐ AOC #200.2	☐		☐	☐ AOC #200.7	☐		☐
☐ AOC #200.3	☐		☐	☐ AOC #200.8	☐		☐
☐ AOC #200.4	☐		☐	☐ AOC #200.9	☐		☐
☐ AOC #200.5	☐		☐	☐ AOC #200.10	☐		☐

-OR-

General AOC Testing
☐ OQSG Written: CT 60 (General Abnormal Operating Condition

E. PERFORMANCE TEST STEPS/AOCs REVIEW

The purpose of this review is to ensure that test steps captured under Section B, Performance or Simulation Evaluation, are accurately reflecting the steps needed to perform this covered task in a manner that ensures the safe operation of pipeline facilities. Please note you can still approve the test steps if your evaluation contains 'N/A' sections if these steps will never be performed by individuals in their current job status or if it is a test step that is never done in your specific region/area. **If the test steps need updating or other modifications because it does not accurately capture or is missing critical steps for this particular covered task, contact the Administrator immediately with your recommended changes.**

Are the Covered Task Performance Test Steps and AOCs Still Current/Applicable?	☐ No	☐ Yes
Comments/Recommendations:		

F. SIGNATURES/DATES

OQT Evaluator (Print Name):	Date
Signature:	
Employee (Print Name):	**Date**
Signature:	

G. DOCUMENT VERSION LOG

Version Number	Version Date	Effective Date	Task Member(s)	Description of Change(s)
1.0	12/18/06		OQ Steering Committee	
2.0	08/22/07	08/22/07	OQ Administrator	MOC #42 – Formatting Changes
3.0	11/06/07	11/06/07	OQ Administrator	MOC #49 – Formatting Changes
4.0	08/08/08	08/08/08	OQ Administrator	MOC #55 – Template Formatting Updates
5.0	11/21/08	11/21/08	OQ Administrator	MOC #59 – Updates Added to all OQT Evaluation Templates (New Section E)
6.0	03/15/10	03/15/10	OQ Steering Committee	MOC #70 – Updated per PHMSA Recommendations

ENBRIDGE US

PROTOCOL 3.01 - Development/Documentation of Areas of Qualification for Individuals Performing Covered Tasks

SECTION 11.0 | MONITORING OQ PLAN PERFORMANCE

The OQ Steering Committee reviews the OQ Plan annually, not to exceed 15 months, to implement recommended improvements as provided through the management of change process (Section #9.0).

There are yearly Protocol 9 audits performed during PHMSA field inspections. Any suggested improvements are discussed during the annual OQ Steering Committee meeting and implemented as needed.

An investigation is completed on all incidents/accidents and procedural recommendations are reviewed and approved by the OQ Steering Committee (Section #9.0)

The Compliance department conducts internal audits (e.g., Protocol 9 audits, integrated pre-audit reviews, Supervisor Management Performance Standards).

ENBRIDGE US

PROTOCOL 3.02 - Covered Task Performed by Non-Qualified Individual

6.2.3 Span of Control Ratio

Span of control ratios for covered tasks were adopted from industry standards (API Approved Liquid/Gas Covered Task List), guidance papers (ASME B31Q) and industry best practices and approved by the OQ Steering Committee. In general, the span of control ratio is a 1:2 ratio (one qualified worker can oversee up to two non-qualified workers), unless otherwise indicated (Appendix A, Section #12.1 or Appendix F, Section #17.7).

~~Note:~~ **Enbridge Best Practice:** Non-qualified workers should be qualified within the first five days of performing each covered task. On day six, the individual should either become qualified or removed from performing that particular covered task.

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~~Enbridge US 5 day rule applies to contractors. Non-qualified workers MUST become operator qualified within the first five days of performing each covered task. Therefore, on day 6, the non-qualified individual should have either become qualified or they should be removed from performing that particular covered task.~~

Factors that the qualified individual should consider which may reduce the span of control ratio, could include, but is not limited to: noise, visual obstructions, weather or job site conditions that make it more difficult for an individual to observe others.

6.2.4 Non-Qualified Worker Limitations

When performing one or more covered tasks for Enbridge US, non-qualified workers must become operator qualified within the first five working days of performing each covered task.

Exception: The Enbridge US 5 day best practice guidelines~~rule~~ do ~~does~~ not apply to the CCO or Enbridge US employees. Initial training for CCO employees takes 4-12 months to ensure employees thoroughly understand their job responsibilities. This training is supervised by qualified Control Center personnel. The PBT training period for Enbridge US employees varies based upon individual performances.

~~Non-Qualified individuals will not be permitted to perform the following covered tasks.~~ Only qualified individuals may perform the following covered tasks:

- Non-Destructive Testing – ASNT Certification and AOC Test required.
- Tank Inspection (Formal In-Service and Formal Out-Of-Service) – API 653 Certification and AOC testing (In-Service inspections) required.
- Welding – Company specific welding procedure and AOC test required.
- Tapping on Stopples – Zero span of control applies to Contractors Only (Appendix F, Section #17.7: Covered tasks #40.7 and #40.8).

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6.3 Required Re-Qualification After Qualification (Enbridge US Employees/Contractors)

6.3.1 PHMSA Reportable Incident/Accident

If a qualified individual is involved in a PHMSA reportable incident/accident (49 CFR Part 191 or 49 CFR Part 195) while performing a covered task and it is determined that the individual's performance contributed to the incident/accident, the individual must be re-qualified prior to further performance of the covered task. If it is determined that the individual's performance did not contribute to the incident/accident, the individual does not need to be re-qualified and they

SECTION 17.1 | APPENDIX F: CONTRACTOR OPERATOR QUALIFICATIONS PROCESS

1) The Contractor Operator Qualification (OQ) process begins when a need for contractor services is identified by the Project Manager (PM) or Designee.

2) The scope of the work must first be identified by the Project Manager (PM) or Designee in order to identify any personnel OQ covered task requirements.

3) After the scope of work is known, the Project Manager (PM) or Designee compares it to the OQ Check List Assignment report **(Appendix F: #17.2)** to determine if the scope involves OQ covered tasks.

4) The Project Manager (PM) or Designee determines if there are OQ covered tasks associated with the project. If no OQ covered tasks are associated with the project, the Project Manager (PM) or Designee checks this box on the OQ Check List Assignment report **(Appendix F: #17.2)**, files this report in the Project File and then continues with the contractor bid process.

5) If there are OQ covered tasks associated with the project, the Project Manager (PM) or Designee is to complete the OQ Check List Assignment report **(Appendix F: #17.2 or use Template in #17.3)** and insert this list in the contractor bid package and include as part of the contract.

6) During the Pre-construction meeting, the Project Manager (PM) or Designee is to provide a list **(Appendix F: #17.2 or #17.3)** of OQ covered tasks assigned to the project to the Contractor. This information should also be on file at the project site. *Note: It is the PM's or Designee's responsibility to keep this list updated whenever covered tasks are added, deleted or modified.*

7) The Contractor must provide a list of qualified and non-qualified personnel that will be performing OQ covered tasks to the Project Manager (PM) or Designee at least 2 full working days prior to commencement of work **(See Appendix F: #17.4 and #17.5).**

8) The Project Manager (PM) or Delegated Personnel (Engineer, On-Site Enbridge Representative, Inspector, etc.) is to validate the list of OQ qualified and non-qualification personnel via ISNetWorld file **(See Appendix F: #17.4 and #17.5)**, as well as:

a. File On-Site and within the project file the validated list of qualified and non-qualified personnel.

b. Verify appropriate span of control is maintained, as well as the Enbridge U.S.5 day best practice **(See #17.4 section #6 for details)**.

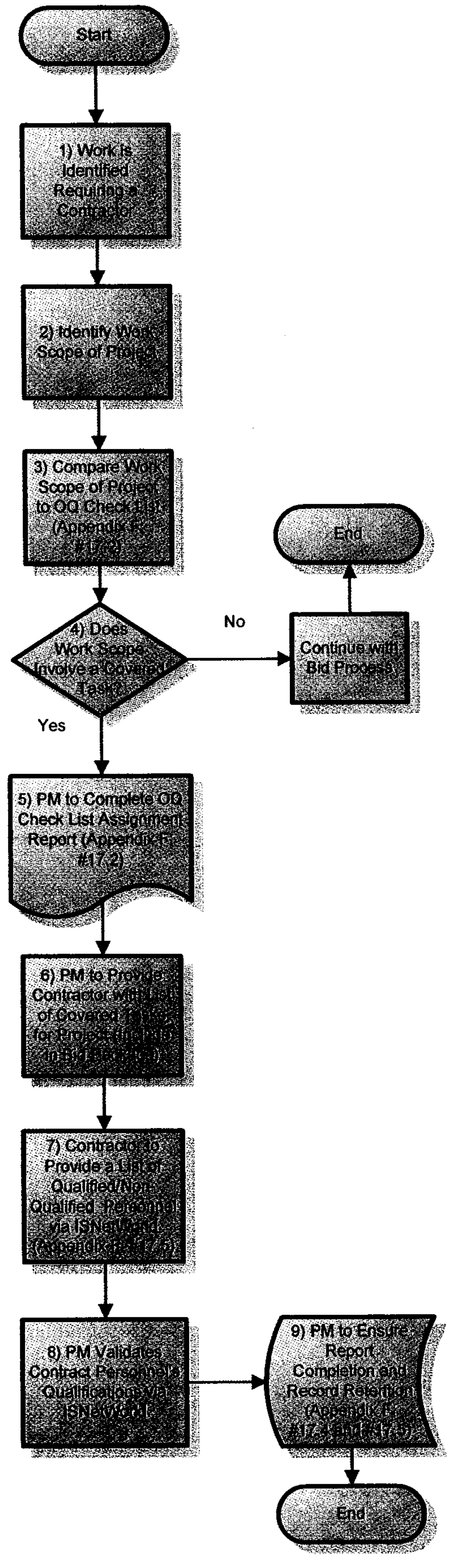
c. Check workers' picture id's prior to start of work to confirm identify of qualified workers.

d. Continue the verification process of qualified and non-qualified workers via ISNetWorld as needed throughout the project.

e. Make sure qualification dates remain current throughout the scope of the project.

f. Check an individual's qualification record for any suspensions.

9) The Enbridge On-Site Representative or Inspector is responsible for ensuring that the appropriate Contractor OQ Report information is completed **(See Appendix F: #17.5 Option Examples)** and filed in the Project File.



6) <u>**Contractor's Responsibility to Provide List of Available OQ Qualified Employees**</u> - The Project Manager (PM) or Designee will provide to the Contractor an OQ Check List Assignment Report **(Appendix F: #17.2 or #17.3)** showing the covered tasks that will be performed by the Contractor on this project. The Contractor will respond by providing a list of personnel who will be either performing the checked covered tasks or directly observing those who will be performing the covered tasks who are not OQ qualified.

In general, the span of control ratio is a 1:2 ratio (one qualified worker can oversee up to two non-qualified workers), <u>unless otherwise indicated</u> (Appendix F, Section #17.7). ~~***Note: Enbridge US 5 day rule applies to contractors.***~~

With regard to the use of Non-qualified workers performing OQ covered tasks, the Enbridge US OQ Plan states:

- Non-qualified individuals may perform covered tasks when directed and observed by a qualified individual who will ensure immediate corrective action is taken when necessary.
- Qualified individuals overseeing non-qualified workers are responsible for the correct and safe performance of the covered task(s).

Enbridge Best Practice: Non-qualified workers should be qualified within the first five days of performing each covered task. On day six, the individual should either become qualified or removed from performing that particular covered task.
~~***Exception Enbridge US 5 DAY RULE: Non-qualified workers MUST become operator qualified within the first five days of performing each covered task. Therefore, on day 6, the non-qualified individual should have either become qualified or they should be removed from performing that particular covered task.***~~

7) <u>**Contractor's Reporting of OQ Qualified Employees**</u> - Enbridge US uses the ISNetworld internet Compliance Records Management system as the documentation source to identify qualified workers prior to the beginning of work and for the duration of any project which includes covered tasks. Contractors may utilize the Enbridge US Covered Task Worker ID/Contractor OQ reports or ISNetWorld's Gap Matrix Contractor OQ reports in order to provide the Project Manager or Designee with required information **(See Appendix F: #17.5 Options A-E)**.

<u>**Contractor ISNetWorld Instructions for Creating OQ Gap Matrix Report for Assigned Personnel:**</u>

a. Login to ISNetWorld Website using your Company's name and password. If you are not set up, talk to your Company ISNetWorld administrator about this.
b. Click on "My Company" tab/link.
c. Click on "Personnel" tab/link.
d. Click on "Employee Report" tab/link.
e. Click on "Generate OQ Reports" tab/link.
f. Follow steps on screen to create the report you need. Note: When you are asked to select the OQ covered tasks, **select <u>only</u> the OQ covered tasks and personnel that are applicable to this project (See Appendix F: #17.2 or #17.3).**
g. Download your information into an Excel Spreadsheet and verify it contains the Enbridge US requested information **(See Appendix F: #17.2 or #17.3, #17.4, and #17.5)**.
h. Identify all non-qualified workers per OQ covered task.

<u>**ISNetWorld Gap Matrix Reporting Requirements:**</u> The Contractor should review the extracted ISNetWorld report to ensure the following:

17.6 PROJECT MANAGER/DESIGNEE OQ QUICK CHECK:

☐	Identify OQ covered tasks the Contractor will need qualified personnel on for the project by using the OQ Check List Assignment report (**Appendix F: #17.2 or #17.3**).
☐	Insert project specific OQ covered task information (**Appendix F: #17.2 or #17.3**) in contractor bid package and include as part of the contract.
☐	Verify awarded Contractor has a subscription to ISNetWorld. If not, provide them with the appropriate ISNetWorld contacts (**See Appendix F: #17.4**).
☐	Obtain list of qualified and non-qualified workers who will be performing OQ covered tasks from the Contractor at **least 2 Full Working Days (Enbridge Best Practice Recommendation) prior** to commencement of work (**See Appendix F: #17.4, #17.5**).
☐	Verify qualification status of the personnel provided by the Contractor (**Appendix F: #17.5**) via ISNetWorld (Website location): www.isnetworld.com. If the Enbridge US project manager or designee needs access to ISNetWorld, send an email to the Enbridge US OQ Compliance Analyst (Kelly Kowalczak: kelly.kowalczak@enbridge.com) with your access request along with your HR employee number, which will be used for your password.
☐	Provide Enbridge On-Site Representative or Inspector with all pertinent project OQ information that is applicable to the project in case of an audit (e.g., Enbridge US OQ Plan, OQ Check List Assignment - **Appendix F: #17.2 or #17.3**, etc.).
☐	Communicate OQ Responsibilities to Enbridge US On-Site Representative or Inspector and notify them of any ongoing OQ requirements (**See Appendix F: #17.1 - Flowchart for specifics**).
☐	Provide a list of Contractor names of the verified qualified and non qualified workers to the On-Site Enbridge US Representative or Inspector prior to commencement of work (**Appendix F: #17.5**).
☐	Check that appropriate span of control is maintained and the Enbridge US 5-day guidance practice applies to any non-qualified workers. **Enbridge Best Practice:** Non-qualified workers should be qualified within the first five days of performing each covered task. On day six, the individual should either become qualified or removed from performing that particular covered task.
☐	Check the Covered Task Worker ID/Contractor OQ report (**Appendix F: #17.5**) provided by Contractor for completion. Areas to check include: 1) Header is completed (Contractor name, start/end dates, project name, etc.); 2) Check box is completed identifying reason why report is being filled out (e.g., start of project, change in Contractor's Crew, etc.); 3) Report contains only the covered tasks identified by Project Manager/Designee for this project (**Appendix F: #17.2 or #17.3**) and the personnel that are specifically assigned to perform this work; 4) Report clearly identifies any non-qualified workers and OQ covered tasks they are working on.
☐	Retain the completed Covered Task Worker ID/Contractor OQ report (**Appendix F: #17.5**) in the Project File, PLM Reporting or the Job File in order to comply with government reporting requirements.

****NOTE: Any <u>new</u> personnel to the project needs to have their qualifications verified against the Enbridge US Contractor OQ Covered Task List (Appendix F: #17.7) prior to being allowed to perform any covered task(s).**

APPENDI. ;ECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS							EXPIRATION PERIOD (months)
			NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	
			NCCER Written Assessments: PMT (40) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: PMT2 (40) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: PMT1 (40) OR NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT1 (40) OR NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (40) OR NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (40) OR NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT1 (40) OR NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (40) NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (40)				NCCER Written Assessments: AOCF () OR eWebOQ : 412HOTT (Hot Tapping and Stopping) AND NCCER Performance Verifications : PV406 (PV406) AND NCCER Written Assessments: AOCFG ()			36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36 36
40.7	Tapping a pipeline 2" and under	1:0*	NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91))	OQSG - Performance : CT36 (Performing General Pipeline Repair Activities)		MEA Knowledge Test : MEA1290 (KNT195-3605 Perform General Pipeline Repair Activities)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions)		NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	36

APPENDI ;ECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
	*Non-qualified contract workers are not allowed to perform this covered task.		AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities)		AND MEA Performance Evaluation : MEA1241 (PEF195-3605 Perform General Pipeline Repair Activities)	AND eWebOQ : 412HOTT (Hot Tapping and Stopping)		AND TD Williamson-Linemaster Certified Technician : CT50 (Class, Written Test, Observation, Field Audit & Review Board)	36
			OR NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91))	AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			AND NCCER Performance Verifications : PV407 (PV407)		OR NCCER Written Assessments: AOCF ()	36
			AND NCCER Written Assessments: AOCF ()	OR NCCER Performance Verifications : PV407 (PV407)			OR eWebOQ : 412HOTT (Hot Tapping and Stopping)		AND TD Williamson-Linemaster Certified Technician : CT50 (Class, Written Test, Observation, Field Audit & Review Board)	36
			OR NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91))	AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities)			AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)		OR NCCER Written Assessments: AOCFG ()	36
			AND NCCER Written Assessments: AOCFG ()	AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			AND NCCER Performance Verifications : PV407 (PV407)		AND TD Williamson-Linemaster Certified Technician : CT50 (Class, Written Test, Observation, Field Audit & Review Board)	36
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)				OR eWebOQ : 412HOTT (Hot Tapping and Stopping)			36
			AND NCCER Performance Verifications : PV407 (PV407)				AND NCCER Performance Verifications : PV407 (PV407)			36
			AND NCCER Written Assessments: PMT (40)				AND NCCER Written Assessments: AOCF ()			36
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)				OR eWebOQ : 412HOTT (Hot Tapping and Stopping)			36
			AND NCCER Performance Verifications : PV407 (PV407)				AND NCCER Performance Verifications : PV407 (PV407)			36
			AND NCCER Written Assessments: PMT2 (40)				AND NCCER Written Assessments: AOCFG ()			36
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)							36
			AND NCCER Performance Verifications : PV407 (PV407)							36
			AND NCCER Written Assessments: PMT1 (40)							36
			OR NCCER Performance Verifications : PV407 (PV407)							36
			AND NCCER Written Assessments: AOCF ()							36
			AND NCCER Written Assessments: PMT (40)							36
			OR NCCER Performance Verifications : PV407 (PV407)							36
			AND NCCER Written Assessments: AOCF ()							36
			AND NCCER Written Assessments: PMT2 (40)							36

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			OR NCCER Performance Verifications : PV407 (PV407) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT1 (40)							36 36 36
			OR NCCER Performance Verifications : PV407 (PV407) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (40)							36 36 36
			OR NCCER Performance Verifications : PV407 (PV407) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (40)							36 36 36
			OR NCCER Performance Verifications : PV407 (PV407) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT1 (40)							36 36
40.6	Tapping a pipeline 2 1/2" and larger *Non-qualified contract workers are not allowed to perform this covered task.	1:0*	NCCER Contren Learning Series : 62306-02 (Hot Tapping and Stoppling®- 2.5" and Larger (CT 40.6, 40.8, 40.9, 40.91)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	OQSG - Performance : CT36 (Performing General Pipeline Repair Activities) AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1290 (KNT195-3605 Perform General Pipeline Repair Activities) AND MEA Performance Evaluation : MEA1241 (PEF195-3605 Perform General Pipeline Repair Activities)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 412HOTT (Hot Tapping and Stopping) AND NCCER Performance Verifications : PV408 (PV408)		NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND TD Williamson-Linemaster Certified Technician : CT50 (Class, Written Test, Observation, Field Audit & Review Board)	36 36
			OR NCCER Contren Learning Series : 62306-02 (Hot Tapping and Stoppling®- 2.5" and Larger (CT 40.6, 40.8, 40.9, 40.91)) AND NCCER Written Assessments: AOCF ()	OR NCCER Performance Verifications : PV408 (PV408) AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			OR eWebOQ : 412HOTT (Hot Tapping and Stopping) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV408 (PV408)		OR NCCER Written Assessments: AOCF () AND TD Williamson-Linemaster Certified Technician : CT50 (Class, Written Test, Observation, Field Audit & Review Board)	36 36
			OR NCCER Contren Learning Series : 62306-02 (Hot Tapping and Stoppling®- 2.5" and Larger (CT 40.6, 40.8, 40.9, 40.91)) AND NCCER Written Assessments: AOCFG ()						OR NCCER Written Assessments: AOCFG () AND TD Williamson-Linemaster Certified Technician : CT50 (Class, Written Test, Observation, Field Audit & Review Board)	36 36
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: PMT (40)				OR eWebOQ : 412HOTT (Hot Tapping and Stopping) AND NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCF ()			36 36 36

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: PMT1 (40)				OR eWebOQ : 412HOTT (Hot Tapping and Stopping) AND NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCFG ()			36 36 36
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: PMT2 (40)							36 36 36
			OR NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (40)							36 36 36
			OR NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (40)							36 36 36
			OR NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT1 (40)							36 36 36
			OR NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (40)							36 36 36
			OR NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (40)							36 36
			OR NCCER Performance Verifications : PV408 (PV408) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT1 (40)							36 36 36
40.9	Sealing the pipeline with a stopple plugging machine	1:2	NCCER Contren Learning Series : 62306-02 (Hot Tapping and Stopping®- 2.5" and Larger (CT 40.6, 40.8, 40.9, 40.91)) AND	OQSG - Performance : CT36 (Performing General Pipeline Repair Activities) AND		MEA Knowledge Test : MEA1290 (KNT195-3605 Perform General Pipeline Repair Activities) AND	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND		NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND	36

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PROTOCOL 4.02 - Evaluation of Individual's Capability to Recognize and React to AOCs

8.0 CONTRACTOR QUALIFICATION GUIDELINES

8.1 Contractor Standards

8.1.1 Contractor Performance Standards

Contractors engaged to perform covered task work on Enbridge US pipeline systems must comply with the Enbridge US OQ Plan.

8.1.2 Contractor Compliance Documentation Standards

Documentation of qualified workers performing covered tasks must be provided to Enbridge US prior to commencing the covered task work, kept current for the duration of the work and individual's OQ records submitted in a timely manner to ISNetWorld, which retains records in accordance to regulatory requirements.

Note: It is the responsibility of the contractor to train contract workers.

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8.2 Contractor Evaluation Criteria/Qualification Documentation

8.2.1 Contractor Evaluation Criteria/Qualification Documentation (Prior to May 15, 2009)

- Contractor documentation that demonstrates qualification of their employees under Subpart G in 49 CFR Part 195 or Subpart N in 49 CFR Part 192 must be submitted for approval prior to the start of covered task work.

- Contractors may satisfy initial/subsequent qualification requirements by one of the following evaluation methods:
  a) Documented evidence of contractor qualification (Covered Tasks and Abnormal Operating Conditions) via observation of performance/simulation or written test pursuant to applicable regulations through an operator approved third-party vendor (see Enbridge US covered task list in ISNetWorld for details); or
  b) Documented by the same method stated herein for Enbridge US employees for special circumstances.

- Companies who contract to supply 24-hour pipeline, gas and terminal operation control services for Enbridge US must provide on line access to a current database containing qualification data for their operators.

8.2.2 Contractor Evaluation Criteria/Qualification Documentation (EFFECTIVE MAY 15, 2009)

Evaluation of a contractor's knowledge, skills and ability (KSAs) to perform a covered task must meet an Enbridge US approved evaluation method (Appendix F: #17.7 Contractor OQ Covered Task List) as follows:

1. Performance test
Contractor must pass a performance test through an accredited Enbridge US approved third-party vendor.

2. **Written knowledge-based assessment test**
Contractor must pass a written knowledge-based assessment test through an accredited Enbridge US approved third-party vendor.

3. **General Abnormal Operating Condition (AOC) test**
Contractor must pass a general AOC test through an Enbridge US approved third-party vendor in order to recognize and react to abnormal operating conditions (AOCs) that may occur while performing the identified covered task. In addition, site specific AOCs are addressed by the Job Plan and Safe Work Permits (O&MP Book 2).

- Contractors are to submit all qualifications to ISNetWorld (JS-518 unless otherwise specified) prior to the start of covered task work.

- Management approval is required for any special circumstances where contractors will be subject to the Enbridge US employee evaluation methods.

8.3 Third-Party Vendor Qualification

Third-party vendor qualification options may be considered upon presentation of valid programs. Enbridge US (JS - 518) currently recognizes and accepts only the following third party OQ vendors:

- National Center for Construction, Education and Research (NCCER);
- Enbridge Technology;
- Solar Turbines;
- Operator Qualification & Solutions Group (OQSG);
- NACE;
- EWebOQ;
- T.D. Williamson, Inc. (TDW);
- Midwest Energy Association (MEA).

The Enbridge US covered task list (ISNetWorld bulletin board and Appendix F, Section #17.7) provides details as to the exact evaluation methods that are acceptable for completion of OQ testing. Contractors using third party vendors must submit all required documentation to ISNetWorld in order to meet certification requirements.

Industry certifications (e.g., API 653 and ASNT) may also be used as part of an individual's qualification to perform a covered task, but only for covered tasks indicated on the Contractors Covered Task List (Appendix F, Section #17.7). However, if this is the method used for qualification, the contractor must also be evaluated on AOCs to be qualified to perform this task.

8.3.1 National Center for Construction, Education and Research (NCCER)

Enbridge US accepts a combination of the following NCCER qualifications per Enbridge US covered task list (Appendix F, Section #17.7 for details):

- Performance Verification, and;
- Training Module (Contren Learning Series includes Performance Verification and Written Test), or Written Assessment Testing, and;
- AOC Assessment Test.

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PROTOCOL 5.01 - Personnel Performance Monitoring

- Document qualification information in the appropriate database within 30 days after completing evaluations. Any records submitted after 30 days must be approved by General Management.
- Verify the effectiveness of OQ test steps through the OQT Evaluation process.
- Ensure a qualified individual is assigned to any non-qualified worker performing covered tasks.
- Ensure all employees new to their area are qualified to perform the appropriate covered tasks.
- Designate an Evaluator, with job specific knowledge, to assist in the evaluation of individuals and tasks, when necessary (Subject to Section #5.7 requirements).
- Report any OQ test step updates or recommendations to Administrator.
- Understand and comply with the Enbridge US OQ Plan.

3.5 Individual

- Become fully qualified in appropriate covered tasks.
- Oversee the performance of covered tasks by those not qualified upon request of his/her supervisor.
- As encountered, identify and report recommended improvements in test steps to supervision.
- Communicate to management if the individual feels they are not qualified to perform a covered task.
- Understand and comply with the Enbridge US OQ plan.

3.6 Project Manager or Designee

- Communicate to contractors Enbridge US expectations and responsibilities for OQ requirements (Appendix F, Section #17.4).
- Include a listing of applicable covered tasks in project specifications (Appendix F, Section #17.2).
- Validate the contractor's list of OQ qualified and non-qualification personnel via ISNetWorld before commencement of work.
- Ensure that a qualified contract worker is present to oversee the performance of any covered task performed by any non-qualified contract personnel.
- Ensure the appropriate span of control is maintained, as well as Enbridge US 5 day rule (Section #6.2.4 and Appendix F, Section #17.2).
- Ensure qualification dates remain current throughout the scope of the project and the Inspector or Enbridge US On-Site Representatives are fulfilling their responsibilities (Appendix F, Section #17.4).
- Ensure OQ reporting requirements (Appendix F, Section #17.5) for contractor work is maintained and retained within the appropriate files (e.g., Project File/ISNetWorld).
- Check that contractor's records have not been suspended on any assigned OQ covered tasks.
- Understand and comply with the Enbridge US OQ plan.

3.7 Company Inspector or Enbridge US On-Site Representative

- Validate and ensure documentation of the contractor employees' qualifications (Appendix F, Section #17.5, Examples: A-F).

can resume work on the covered task (Appendix D, Section #15.1 - Post Incident/Accident Process flowchart and Appendix D, Form #15.2).

6.3.2 Flawed Procedure

If the task was performed properly yet there is evidence that the procedure is flawed, the procedure will be re-written and follow the applicable change management process. Direction to re-qualify all affected individuals may follow if the procedure is revised and necessitates this.

6.3.3 Post Incident/Accident Process

The Post Incident/Accident Process flowchart (Appendix D, Section #15.1) illustrates the action taken by the supervisor should an incident/accident occur. The Operator Qualification (OQ) Re-assessment Review Form (Appendix D, Form #15.2) must be filled out anytime personnel need to go through OQ reassessment testing.

6.3.4 Suspension

Suspension of qualification(s) should be considered for, but not limited to, the following circumstances:

- Failure to complete requirements (such as training or all testing criteria elements).
- If there is reason to believe an individual's performance of a covered task may have affected pipeline safety or integrity adversely, or cannot be ruled out as a contributing factor.
- Re-qualification is not completed by the due date.
- Discovery that an individual might have been improperly evaluated, or
- Whenever there is reasonable belief that an individual is no longer qualified to perform a covered task(s).

The suspension shall continue until that individual has either been re-qualified, or the subsequent investigation determines that the individual's performance did not contribute to the accident/incident. Notification of the suspension needs to be given to the Administrator in order to flag that particular OQ covered task record accordingly within ISNetWorld. If the record is not in ISNetWorld at the time of suspension due to a timing lag (e.g., official vendor transcripts accepted during the interim period), e-mail notification of the individual's suspension will to be sent out to all applicable parties. In the interim, the individual may, at Management's discretion, continue to perform other covered tasks that he or she is qualified to perform.

6.3.5 Re-qualification Circumstances

An individual who may no longer be qualified to perform a covered task may be re-qualified on that covered task. Such re-qualification might take place, but is not limited to, circumstances where the individual has:

- Displayed unsatisfactory performance.
- Acquired physical/mental limitations.
- The covered task test step has been significantly re-written.

Enbridge US requires that contractors meet the vendor's ~~certify their own evaluators~~ evaluation requirements via MEA evaluator training requirements to enable them to qualify their own employees as evaluators using the MEA methods mentioned above.

8.4 Contractor Documentation/Work Site Requirements

8.4.1 Internet Compliance Records Management

- Enbridge US uses ISNetWorld Internet Compliance Records Management as the contractor documentation source to identify qualified workers prior to the beginning of work and for the duration of any work that includes covered tasks.
- Contractors, subscribing to ISNetWorld, who propose to provide services to Enbridge US, must grant access to their qualification data by submitting an OQ Report on ISNetWorld updated as personnel changes throughout the job.

8.4.2 Compliance Records Paper Documentation

If timing lags occur where the contractor qualification data is not appearing in ISNetWorld, contractors may submit hard copy qualification data to the Project Manager/Designee at a minimum of seven working days prior to work commencing. If hard copies of qualification records are accepted, the evaluation methods must be compared to the Enbridge US covered task list (Appendix F, Section #17.7) to ensure OQ qualification validity. **Note:** Most problems in this area are due to contractors not submitting an OQ report to the specified Enbridge US Job Site (Appendix F, Section #17.4, Step #5).

The Enbridge US covered task list (located in ISNetWorld) provides details as to the exact evaluation methods that are acceptable for completion of OQ testing. This covered task list is also located in Appendix F, Section #17.7.

8.4.3 Record Retention

Contractor qualification records will be retained within the ISNetWorld system and/or by Enbridge US for five years.

8.4.4 Submission of Contractor Documentation

Contractors must provide the names and the qualification status of all individuals they intend to assign to Enbridge US jobs that include covered tasks at least 2 full working days prior to the start of work. The Covered Task Worker ID form may be used for this purpose (Appendix F, Section #17.5, Examples: A - E).

The following identifying data is required:
- The name(s) of qualified and non qualified individual(s).
- Each covered task specific to the work being performed.
- Dates of satisfactory completion of covered tasks and AOC evaluation(s) via ISNetWorld.

Enbridge US Project Manager/Designee will verify the qualifications of the proposed workers via proper documentation and send a list of names to the Enbridge US job site representative. In addition, the Enbridge US Project Manager/Designee will check to make sure that an individual's records have not been suspended on any assigned OQ covered tasks. **Note:** It is the responsibility of the Contractor to provide any necessary language translations to ensure an understanding of OQ requirements for contract employees with special needs considerations or barriers.

8.4.5 Contractor Work Site IDs

Qualified worker picture ID's may be checked prior to the start of work at the job site to confirm the identity of qualified individuals as needed.

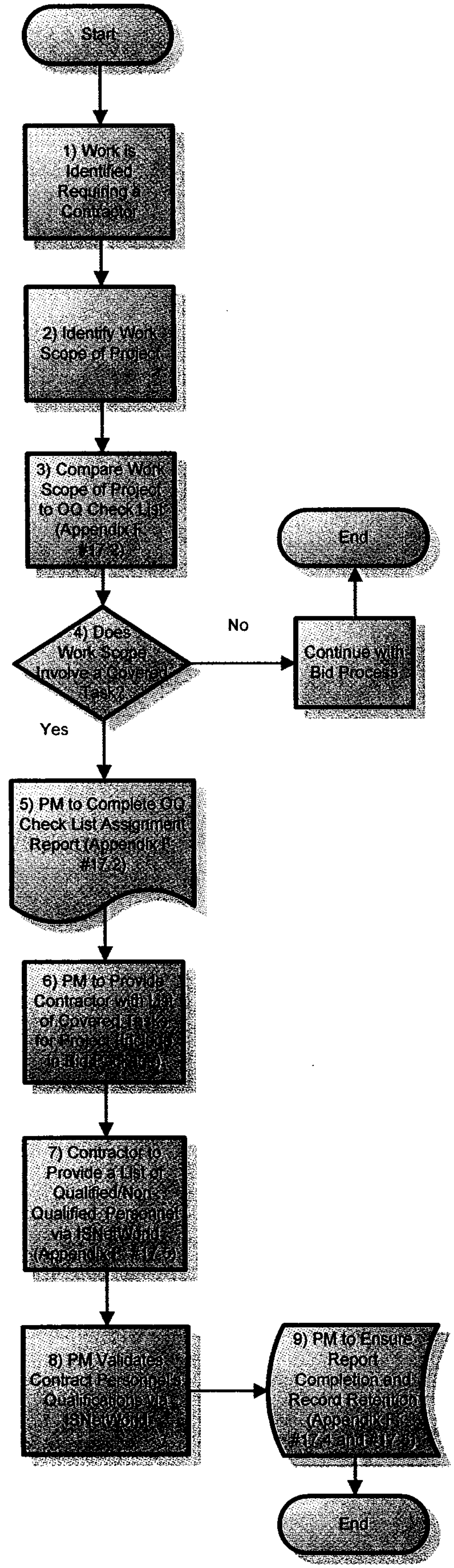
8.4.6 Contractor OQ Report

A representative of Enbridge US and a contractor representative will complete the Contractor OQ Report (Appendix F, Section #17.5) listing the name and qualification status of each worker.

8.4.7 OQ Report Filing

Completed Contractor OQ Reports are kept in the Project File.

SECTION 17.1 | APPENDIX F: CONTRACTOR OPERATOR QUALIFICATIONS PROCESS



1) The Contractor Operator Qualification (OQ) process begins when a need for contractor services is identified by the Project Manager (PM) or Designee.

2) The scope of the work must first be identified by the Project Manager (PM) or Designee in order to identify any personnel OQ covered task requirements.

3) After the scope of work is known, the Project Manager (PM) or Designee compares it to the OQ Check List Assignment report **(Appendix F: #17.2)** to determine if the scope involves OQ covered tasks.

4) The Project Manager (PM) or Designee determines if there are OQ covered tasks associated with the project. If no OQ covered tasks are associated with the project, the Project Manager (PM) or Designee checks this box on the OQ Check List Assignment report **(Appendix F: #17.2)**, files this report in the Project File and then continues with the contractor bid process.

5) If there are OQ covered tasks associated with the project, the Project Manager (PM) or Designee is to complete the OQ Check List Assignment report **(Appendix F: #17.2 or use Template in #17.3)** and insert this list in the contractor bid package and include as part of the contract.

6) During the Pre-construction meeting, the Project Manager (PM) or Designee is to provide a list **(Appendix F: #17.2 or #17.3)** of OQ covered tasks assigned to the project to the Contractor. This information should also be on file at the project site. *Note: It is the PM's or Designee's responsibility to keep this list updated whenever covered tasks are added, deleted or modified.*

7) The Contractor must provide a list of qualified and non-qualified personnel that will be performing OQ covered tasks to the Project Manager (PM) or Designee at least 2 full working days prior to commencement of work **(See Appendix F: #17.4 and #17.5).**

8) The Project Manager (PM) or Delegated Personnel (Engineer, On-Site Enbridge Representative, Inspector, etc.) is to validate the list of OQ qualified and non-qualification personnel via ISNetWorld file **(See Appendix F: #17.4 and #17.5)**, as well as:

a. File On-Site and within the project file the validated list of qualified and non-qualified personnel.

b. Verify appropriate span of control is maintained, as well as the Enbridge U.S.5 day best practice **(See #17.4 section #6 for details)**.

c. Check workers' picture id's prior to start of work to confirm identify of qualified workers.

d. Continue the verification process of qualified and non-qualified workers via ISNetWorld as needed throughout the project.

e. Make sure qualification dates remain current throughout the scope of the project.

f. Check an individual's qualification record for any suspensions.

9) The Enbridge On-Site Representative or Inspector is responsible for ensuring that the appropriate Contractor OQ Report information is completed **(See Appendix F: #17.5 Option Examples)** and filed in the Project File.

ENBRIDGE US

PROTOCOL 5.02 - Reevaluation Interval and Methodology for Determining the Interval

- At management's discretion, been away from work for a prolonged period of time (e.g., military leave, family medical leave, etc.).

6.3.6 Reinstatement

Suspended or disqualified qualification(s) may be reinstated when one of the following has been completed:

- It has been determined and documented that the individual was and still is qualified.
- The individual has completed action that resolves the concern that caused the suspension/disqualification (e.g., training, evaluation testing, completion of change communications, etc.).

6.3.7 Re-qualification Interval

After initial qualification, subsequent re-qualifications for all individuals must occur within three years (but not to exceed 42 months)*. from the date of the last qualification unless a more frequent re-qualification interval is indicated for a specific task by this OQ Plan. Interval periods for subsequent re-qualifications for covered tasks were adopted from industry standards (API Approved Liquid/Gas Covered Task List), guidance papers (ASME B31Q) and industry best practices and approved by the OQ Steering Committee.

***Exceptions:** OQ covered tasks (e.g., clock spring, welding, etc.) where the re-qualification interval for testing is held to 36 months or less is noted within the respective covered task lists (Appendix A, Section #12.1 or Appendix F, Section #17.7).

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6.4 OQ Process Review and Update

6.4.1 OQ Review by OQ Steering Committee/Administrator

- Covered tasks will be reviewed, updated and communicated by the OQ Steering Committee or Administrator as changes occur.
- The OQ Plan will be reviewed annually (not to exceed 15 months) and updated as necessary.

OQ changes may include:

- Installation of new equipment or technology requiring procedural change.
- Modification of a pipeline facility impacting a covered task.
- Regulatory change.
- Company policy or procedure change.

6.4.2 OQ Review of Regulatory and Industry Updates

The Superior Compliance Department has a formal process to review each Advisory Bulletin and Notice issued via the Department of Transportation Pipeline and Hazardous Material Administration Office of Pipeline Safety (OPS). Compliance maintains subscriptions of the WinDOT software, produced by Viadata L.P. This software monitors OPS activities and provides automated e-mail alerts of OPS notices, alerts and advisories. As the WinDOT notices are released, the contents of each are analyzed for perceived relevance to Enbridge US operations (both CFR 192 and 195). Compliance's primary goal is to distribute this information to those people best equipped to make decisions on whether or not Enbridge US meets compliance requirements or to ascertain that potential changes may need to be made. Notices that contain

Enbridge US Covered Task #	Enbridge US (In-House) OQ Covered Task Name	Description	Re-Evaluation Frequency (specified in years)	Span of Control Ratio	Training	Initial or Post Incident-Accident Re-Assessment	Subsequent	1) Part of Regulation (192 or 195); 2) Performed on Pipeline Facility; 3) Operations or Maintenance Task; 4) Affects Operation or Integrity of Pipeline.	Part 195	Part 192	For Reference Purposes Only B31Q
69	Pipeline Repair: Composite Sleeve	This task includes the preparation and installation of composite sleeves. **Per manufacturer's instructions, if using Clock Spring, re-qualification is required <u>every</u> year for performance testing.**	3 1	1:2	369- PBT OQT: Pipeline Repair: Composite Sleeve **AND/OR** OQSG -OQVerify: CT36 (Performing General Pipeline Repair Activities)	69 - Performance - OQT - Pipeline Repair: Composite Sleeve **AND** 69 - Verbal - OQT - Pipeline Repair: Composite Sleeve **OR** OQSG - Written: CT36 (Performing General Pipeline Repair Activities) **AND** 69 - AOC - OQT - Pipeline Repair: Composite Sleeve **OR** OQSG - Written: CT60 (General Abnormal Operating Conditions)	69 - Performance - OQT - Pipeline Repair: Composite Sleeve **AND** OQSG - Written: CT36 (Performing General Pipeline Repair Activities) **AND** OQSG - Written: CT60 (General Abnormal Operating Conditions)	Y	195.422 (a)	192.711; 192.713; 192.717	Task 1061;
70	Pipeline Repair: Weld Plus Coupling	This task consists of the general maintenance and repair activities that are involved in the safeguarding and prudent operation of a pipeline system.	3	1:2	370- PBT OQT: Pipeline Repair: Weld Plus Coupling **AND/OR** OQSG -OQVerify: CT36 (Performing General Pipeline Repair Activities)	70 - Performance - OQT - Pipeline Repair: Weld Plus Coupling **AND** 70 - Verbal - OQT - Pipeline Repair: Weld Plus Coupling **OR** OQSG - Written: CT36 (Performing General Pipeline Repair Activities) **AND** 70 - AOC - OQT - Pipeline Repair: Weld Plus Coupling **OR** OQSG - Written: CT60 (General Abnormal Operating Conditions)	70 - Performance - OQT - Pipeline Repair: Weld Plus Coupling **AND** OQSG - Written: CT36 (Performing General Pipeline Repair Activities) **AND** OQSG - Written: CT60 (General Abnormal Operating Conditions)	Y	195.422 (a)	192.711; 192.713; 192.717	Task 1051;
71	Pipeline Repair: Stopple	This task includes the insertion and removal of a stopple. It also includes pressure verification and monitoring pressure to assure system pressure requirements are maintained.	3	1:2	371- PBT OQT: Pipeline Repair: Stopple **AND/OR**	71 - Performance - OQT - Pipeline Repair: Stopple **AND**	71 - Performance - OQT - Pipeline Repair: Stopple **AND**	Y	195.422 (a); 195.204; 195.212	192.711; 192.713; 192.717; 192.144; 192.313; 192.627	Task 1131

APPENDI[illegible] SECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
40.3 [illegible]	Clock spring [illegible] *Per manufacturer's instructions, if using Clock Spring, re-qualification is required every year for performance testing.*	[illegible]	NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) OR NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91)) AND NCCER Written Assessments: AOCF () OR NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91)) AND NCCER Written Assessments: AOCFG () OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV403 (PV403) AND NCCER Written Assessments: PMT1 (40) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV403 (PV403) AND NCCER Written Assessments: PMT (40) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV403 (PV403) AND NCCER Written Assessments: PMT2 (40) OR NCCER Performance Verifications : PV403 (PV403) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (40) OR NCCER Performance Verifications : PV403 (PV403)	OQSG - Performance : CT36 (Performing General Pipeline Repair Activities) AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities) AND OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV403 (PV403) AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 409LEAK (Pipeline Leak Repair) AND eWebOQ : 411PURGE (Pipeline Purging) AND NCCER Performance Verifications : PV403 (PV403) OR eWebOQ : 409LEAK (Pipeline Leak Repair) AND eWebOQ : 411PURGE (Pipeline Purging) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV403 (PV403) OR eWebOQ : 409LEAK (Pipeline Leak Repair) AND eWebOQ : 411PURGE (Pipeline Purging) AND NCCER Performance Verifications : PV403 (PV403) AND NCCER Written Assessments: AOCF () OR eWebOQ : 409LEAK (Pipeline Leak Repair) AND eWebOQ : 411PURGE (Pipeline Purging) AND NCCER Performance Verifications : PV403 (PV403) AND NCCER Written Assessments: AOCFG ()			*12 *12 *12 *12 *12 *12 36 *12 36 36 *12 36 36 36 *12 *12 36 36 *12

APPENDI SECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			AND							36
			NCCER Written Assessments: AOCF ()							36
			AND NCCER Written Assessments: PMT (40)							*12
			OR NCCER Performance Verifications : PV403 (PV403)							36
			AND NCCER Written Assessments: AOCF ()							36
			AND NCCER Written Assessments: PMT1 (40)							*12
			OR NCCER Performance Verifications : PV403 (PV403)							36
			AND NCCER Written Assessments: AOCFG ()							36
			AND NCCER Written Assessments: PMT2 (40)							*12
			OR NCCER Performance Verifications : PV403 (PV403)							36
			AND NCCER Written Assessments: AOCFG ()							36
			AND NCCER Written Assessments: PMT (40)							*12
			OR NCCER Performance Verifications : PV403 (PV403)							36
			AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT1 (40)							36
[redacted]	[redacted]	[redacted]	NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91))	OQSG - Performance : CT36 (Performing General Pipeline Repair Activities)		MEA Knowledge Test : MEA1290 (KNT195-3605 Perform General Pipeline Repair Activities)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions)			36
			AND NCCER Written Assessments: AOCF ()	AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities)		AND MEA Performance Evaluation : MEA1241 (PEF195-3605 Perform General Pipeline Repair Activities)	AND eWebOQ : 409LEAK (Pipeline Leak Repair)			36
			OR NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91))	AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			AND eWebOQ : 411PURGE (Pipeline Purging)			36
			AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	OR NCCER Performance Verifications : PV404 (PV404)			AND NCCER Performance Verifications : PV404 (PV404)			36
			OR NCCER Contren Learning Series : 62304-02 (Pipeline Repair (CT 9.5, 37, 40.1, 40.2, 40.3, 40.4, 40.5, 40.7, 40.91))	AND OQSG - Written : CT36 (Performing General Pipeline Repair Activities)			OR eWebOQ : 409LEAK (Pipeline Leak Repair)			36
			AND NCCER Written Assessments: AOCFG ()	AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			AND eWebOQ : 411PURGE (Pipeline Purging)			36
			OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)				AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)			36

APPENDI ;ECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			OR NCCER Performance Verifications : PV410 (PV410) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (41)							36
										36
										36
			OR NCCER Performance Verifications : PV410 (PV410) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (41)							36
										36
										36
			OR NCCER Performance Verifications : PV410 (PV410) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (41)							36
										36
										36
			OR NCCER Performance Verifications : PV410 (PV410) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (41)							36
										36
										36
42	Maintenance Welding on Pipelines									36*
42.1	Repair of arc burns [illegible] * Before welding piping, the welders must, within the previous 6 months and using the same process, have completed a pipe weld that was tested and found acceptable under API 1104, Section 9. Verification of this requirement is a documented NDE report. For Vector Gas, performance qualification requirements are annual per CFR 192 (See API 1104, Section 6, for re-qualification criteria).	[illegible]	NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCF ()	OQSG - Performance : CT38 (Maintenance Welding on Pipelines) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines)		MEA Knowledge Test : MEA1287 (KNT195-2401 Maintenance Welding on Pipelines) AND MEA Performance Evaluation : MEA1238 (PEF195-2401 Maintenance Welding on Pipelines)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 600WELD (Electric Arc Welding)			36*
			OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions)	AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			AND eWebOQ : 601WQUAL (Welder Qualification)			36*
				OR NCCER Performance Verifications : PV421 (PV421)			AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures)			36*
			OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCFG ()	AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			AND NCCER Performance Verifications : PV421 (PV421)			36*
			OR				OR eWebOQ : 600WELD (Electric Arc Welding) AND			36*

APPENDI   ›ECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: PMT (42) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (42)				eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV421 (PV421) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: AOCF () OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV421 (PV421) AND NCCER Written Assessments: AOCFG ()			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*
42.2	Repair of defective welds other than welds containing cracks	1:0	NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCF () OR	OQSG - Performance : CT38 (Maintenance Welding on Pipelines) AND OQSG - Written : CT38 (Maintenance Welding on Pipelines) AND		MEA Knowledge Test : MEA1287 (KNT195-2401 Maintenance Welding on Pipelines) AND MEA Performance Evaluation : MEA1238 (PEF195-2401 Maintenance Welding on Pipelines)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 600WELD (Electric Arc Welding) AND			36* 36*

APPENDI... SECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
	*** Before welding piping, the welders must, within the previous 6 months and using the same process, have completed a pipe weld that was tested and found acceptable under API 1104, Section 9. Verification of this requirement is a documented NDE report. For Vector Gas, performance qualification requirements are annual per CFR 192 (See API 1104, Section 6, for re-qualification criteria).**		NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCFG () OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV422 (PV422) AND NCCER Written Assessments: PMT (42) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV422 (PV422) AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV422 (PV422) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV422 (PV422) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV422 (PV422) AND	OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV422 (PV422) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV422 (PV422) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV422 (PV422) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV422 (PV422) AND NCCER Written Assessments: AOCF () OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV422 (PV422) AND			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV422 (PV422) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (42)				NCCER Written Assessments: AOCFG ()			36* 36* 36* 36* 36*
42.3	Repair of [illegible] on a weld containing a defect other than a crack [illegible] * Before welding piping, the welders must, within the previous 6 months and using the same process, have completed a pipe weld that was tested and found acceptable under API 1104, Section 9. Verification of this requirement is a documented NDE report. For Vector Gas, performance qualification requirements are annual per CFR 192 (See API 1104, Section 6, for re-qualification criteria).	1:0	NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCF () OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCFG () OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: PMT (42) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: PMT2 (42) OR	OQSG - Performance : CT38 (Maintenance Welding on Pipelines) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV423 (PV423) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1287 (KNT195-2401 Maintenance Welding on Pipelines) AND MEA Performance Evaluation : MEA1238 (PEF195-2401 Maintenance Welding on Pipelines)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV423 (PV423) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV423 (PV423) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*

APPENDI. ,ECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (42)				eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: AOCF () OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV423 (PV423) AND NCCER Written Assessments: AOCFG ()			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*
[redacted]	[redacted] * Before welding piping, the welders must, within the previous 6 months and using the same process, have completed a pipe weld that was tested and found acceptable under API 1104, Section 9. Verification of this requirement is a documented NDE report. For Vector Gas, performance qualification requirements are annual per CFR 192 (See API 1104, Section 6, for re-qualification criteria).		NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCF () OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCFG () OR	OQSG - Performance : CT38 (Maintenance Welding on Pipelines) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV424 (PV424) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1287 (KNT195-2401 Maintenance Welding on Pipelines) AND MEA Performance Evaluation : MEA1238 (PEF195-2401 Maintenance Welding on Pipelines)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV424 (PV424) OR eWebOQ : 600WELD (Electric Arc Welding) AND			36* 36* 36* 36* 36* 36*

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS							EXPIRATION PERIOD (months)
			NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	
			NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: PMT (42) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (42)				eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV424 (PV424) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: AOCF () OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV424 (PV424) AND NCCER Written Assessments: AOCFG ()			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*
42.5	Repair of a previously repaired area [illegible]	1:0	NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCF () OR	OQSG - Performance : CT38 (Maintenance Welding on Pipelines) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND		MEA Knowledge Test : MEA1287 (KNT195-2401 Maintenance Welding on Pipelines) AND MEA Performance Evaluation : MEA1238 (PEF195-2401 Maintenance Welding on Pipelines)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 600WELD (Electric Arc Welding) AND			36* 36*

APPENDI. ;ECTION 17.7 CONTRACTORS- OQ COVERED TASK LIST

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
	*** Before welding piping, the welders must, within the previous 6 months and using the same process, have completed a pipe weld that was tested and found acceptable under API 1104, Section 9. Verification of this requirement is a documented NDE report. For Vector Gas, performance qualification requirements are annual per CFR 192 (See API 1104, Section 6, for re-qualification criteria).**		NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCFG () OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: PMT (42) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: AOCFG ()	OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV425 (PV425) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)			eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV425 (PV425) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV425 (PV425) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: AOCF () OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: AOCFG ()			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS NCCER: Initial/Subsequent/OQ Re-assessment Review	OQSG: Initial/Subsequent/OQ Re-assessment Review	NACE: Initial/Subsequent/OQ Re-assessment Review	MEA: Initial/Subsequent/OQ Re-assessment Review	EWebOQ: Initial/Subsequent/OQ Re-assessment Review	SOLAR TURBINES: Initial/Subsequent/OQ Re-assessment Review	TDW: Initial/Subsequent/OQ Re-assessment Review	EXPIRATION PERIOD (months)
			AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV425 (PV425) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (42)							36* 36* 36* 36*
42.6 [illegible]	Replacement of a weld or [illegible] cylinder of pipe [illegible] *** Before welding piping, the welders must, within the previous 6 months and using the same process, have completed a pipe weld that was tested and found acceptable under API 1104, Section 9. Verification of this requirement is a documented NDE report. For Vector Gas, performance qualification requirements are annual per CFR 192 (See API 1104, Section 6, for re-qualification criteria).**	1.0	NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCF () OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) OR NCCER Contren Learning Series : 62308-02 (Maintenance Welding on Pipelines (CT 42)) AND NCCER Written Assessments: AOCFG () OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: PMT (42) OR NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: PMT2 (42) OR	OQSG - Performance : CT38 (Maintenance Welding on Pipelines) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV426 (PV426) AND OQSG - Written : CT38 (Maintenance Welding on Pieplines) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1287 (KNT195-2401 Maintenance Welding on Pipelines) AND MEA Performance Evaluation : MEA1238 (PEF195-2401 Maintenance Welding on Pipelines)	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV426 (PV426) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV426 (PV426) OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*

API/ COOQ COVERED TASKS #	API/ COOQ COVERED TASKS	Span of Control Ratio	EVALUATION METHODS							EXPIRATION PERIOD (months)
			NCCER: Initial/Subsequent/OQ Re-assessment Review	**OQSG:** Initial/Subsequent/OQ Re-assessment Review	**NACE:** Initial/Subsequent/OQ Re-assessment Review	**MEA:** Initial/Subsequent/OQ Re-assessment Review	**EWebOQ:** Initial/Subsequent/OQ Re-assessment Review	**SOLAR TURBINES:** Initial/Subsequent/OQ Re-assessment Review	**TDW:** Initial/Subsequent/OQ Re-assessment Review	
			NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: AOCF () AND NCCER Written Assessments: PMT2 (42) OR NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT (42) OR NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: AOCFG () AND NCCER Written Assessments: PMT2 (42)				eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: AOCF () OR eWebOQ : 600WELD (Electric Arc Welding) AND eWebOQ : 601WQUAL (Welder Qualification) AND eWebOQ : 602WREPR (Weld Repairs and Welding Procedures) AND NCCER Performance Verifications : PV426 (PV426) AND NCCER Written Assessments: AOCFG ()			36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36* 36*
43	Operations of a Pipeline System									
43.1	Start-up of a pipeline	1:1	NCCER Contren Learning Series : 60105-02 (Routine Field and Facility Operations (CT 43.1, 43.2, 43.4) AND NCCER Contren Learning Series : 65102-02 (Control Center Abnormal Operating Conditions) OR NCCER Contren Learning Series : 60105-02 (Routine Field and Facility Operations (CT 43.1, 43.2, 43.4) AND NCCER Written Assessments: AOCCC () OR NCCER Contren Learning Series : 65102-02 (Control Center Abnormal Operating Conditions) AND NCCER Performance Verifications : PV431 (PV431) AND NCCER Written Assessments: FCCOT v3 (43.1) OR NCCER Contren Learning Series : 65102-02 (Control Center Abnormal Operating Conditions) AND NCCER Performance Verifications : PV431 (PV431) AND	OQSG - Performance : CT39 (Operations of a Pipeline System) AND OQSG - Written : CT39 (Operations of a Pipeline System) AND OQSG: Written: CT60 (General Abnormal Operating Conditions) OR NCCER Performance Verifications : PV431 (PV431) AND OQSG - Written : CT39 (Operations of a Pipeline System) AND OQSG: Written: CT60 (General Abnormal Operating Conditions)		MEA Knowledge Test : MEA1272 (KNT195-1414PS Operations of a Pipeline System (Pipeline)) AND MEA Performance Evaluation : MEA1223 (PEF195-1414PS Operations of a Pipeline System (Pipeline))	eWebOQ : 101ABNOR (Recognize & React to Abnormal Operating Conditions & Safety Related Conditions) AND eWebOQ : LQ903 (LQ: Pressure Transmitters) AND NCCER Performance Verifications : PV431 (PV431) OR eWebOQ : LQ903 (LQ: Pressure Transmitters) AND NCCER Contren Learning Series : 66102-02 (Liquid Pipeline General Abnormal Operating Conditions) AND NCCER Performance Verifications : PV431 (PV431) OR eWebOQ : LQ903 (LQ: Pressure Transmitters) AND NCCER Performance Verifications : PV431 (PV431) AND NCCER Written Assessments: AOCF () OR			36 36 36 36 36 36 36 36 36

ENBRIDGE US

PROTOCOL 7.01 – Qualification "Trail" (Maintain Program Records)

ENBRIDGE US

PROTOCOL 8.01 - Management of Changes

can resume work on the covered task (Appendix D, Section #15.1 - Post Incident/Accident Process flowchart and Appendix D, Form #15.2).

6.3.2 Flawed Procedure

If the task was performed properly yet there is evidence that the procedure is flawed, the procedure will be re-written and follow the applicable change management process. Direction to re-qualify all affected individuals may follow if the procedure is revised and necessitates this.

6.3.3 Post Incident/Accident Process

The Post Incident/Accident Process flowchart (Appendix D, Section #15.1) illustrates the action taken by the supervisor should an incident/accident occur. The Operator Qualification (OQ) Re-assessment Review Form (Appendix D, Form #15.2) must be filled out anytime personnel need to go through OQ reassessment testing.

6.3.4 Suspension

Suspension of qualification(s) should be considered for, but not limited to, the following circumstances:

- Failure to complete requirements (such as training or all testing criteria elements).
- If there is reason to believe an individual's performance of a covered task may have affected pipeline safety or integrity adversely, or cannot be ruled out as a contributing factor.
- Re-qualification is not completed by the due date.
- Discovery that an individual might have been improperly evaluated, or
- Whenever there is reasonable belief that an individual is no longer qualified to perform a covered task(s).

The suspension shall continue until that individual has either been re-qualified, or the subsequent investigation determines that the individual's performance did not contribute to the accident/incident. Notification of the suspension needs to be given to the Administrator in order to flag that particular OQ covered task record accordingly within ISNetWorld. If the record is not in ISNetWorld at the time of suspension due to a timing lag (e.g., official vendor transcripts accepted during the interim period), e-mail notification of the individual's suspension will to be sent out to all applicable parties. In the interim, the individual may, at Management's discretion, continue to perform other covered tasks that he or she is qualified to perform.

6.3.5 Re-qualification Circumstances

An individual who may no longer be qualified to perform a covered task may be re-qualified on that covered task. Such re-qualification might take place, but is not limited to, circumstances where the individual has:

- Displayed unsatisfactory performance.
- Acquired physical/mental limitations.
- The covered task test step has been significantly re-written.

- Ensure the appropriate span of control is maintained, as well as the Enbridge US 5 day rule (Section #6.2.4 and Appendix F, Section #17.2).
- If the Company Inspector or Enbridge US On-Site Representative observes a covered task not being performed properly, work can be suspended or the contractor can be removed from that particular covered task.
- If contract worker is involved in an incident/accident and performance is suspected as contributory by the contract Supervisor or Enbridge On-Site Representative, follow Appendix D, Section #15.1 re-qualification process.
- Understand and comply with the Enbridge US OQ plan.

3.8 Contractor

- Ensure workers employed to perform covered tasks on the Enbridge US system are properly qualified through an Enbridge US approved evaluation method (Appendix F, Section #17.7).
- Ensure workers' OQ records are uploaded properly into ISNetWorld (JS-518 unless otherwise specified) prior to the start of covered task work (Appendix F, Section #17.4, Step #5).
- Ensure that a qualified contract worker is present to oversee the performance of any covered task performed by any non-qualified contract personnel who will ensure immediate corrective action is taken when necessary (Section #6.2.1).
- Ensure the appropriate span of control is maintained, as well as Enbridge US 5 day rule (Section #6.2.4 and Appendix F, Section #17.2).
- Provide documentation to Enbridge US indicating required qualification information (Appendix F, Section #17.5).
- If contract worker is involved in an incident/accident and performance is suspected as contributory by the contract Supervisor or Enbridge On-Site Representative, follow Appendix D, Section #15.1 re-qualification process.
- Implement and communicate to contract worker(s) any management of change processes that impact the Enbridge US OQ Plan.
- Understand and comply with the Enbridge US OQ plan.

9.0 CHANGE MANAGEMENT

9.1 OQ Plan Changes

Changes/updates that may affect the OQ Plan, but are not limited to, are as follows:

- Pipeline operations are changed.
- Pipeline equipment and facilities are changed including the use of new equipment and new technology.
- Employee job descriptions are changed.
- Written test steps for covered tasks are added, deleted or modified.
- The Enbridge US organization is changed.
- Enbridge US policies are changed.
- PBT and other training programs (i.e., Control Center) are changed.
- Regulations involving covered tasks are changed.

If these changes impact PBT, OQ evaluation methods or frequencies, the information will be communicated as outlined in the Change Feedback Mechanism (Appendix E, Section #16.2 - Change Management Form) and in the Change Management Methodology (Appendix E, Section #16.1).

Note: Contractors are responsible for implementing and communicating to contract workers any Enbridge US management of change processes.

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9.2 Change Feedback Sources

Change feedback may be received via:

- Regulation.
- Management.
- Administrator.
- Industry/OQC.
- Evaluators.
- Contractors.
- Employees/Supervisors.
- Internal Incident/Accident Investigation Teams.

9.3 Critical Change Feedback

Feedback received which is critical in nature as determined by the OQ Steering Committee and requires immediate action will be communicated (e.g., cease work until training/re-qualification is completed, continue to work but re-qualification needs to be completed by a certain time frame), via email or verbally, by the Administrator or designate to all affected internal and external parties directly following notification. Any interim action necessary will be communicated in this notification.

A critical revision is defined as a revision that may significantly impact the company's business if not implemented correctly, considering the following criteria:

- Regulatory impact.
- Cost Efficiency.
- System Reliability.
- Personal hazard or injury.
- Environmental impact.

- Complexity of the job task.

A non critical revision is any other revision that does not meet the criteria for a critical revision (e.g., slight wording modification made for clarification purposes, typo error corrected, etc.).

9.4 Covered Task Changes

9.4.1 OQ Plan Administrator Assessment

Non-critical OQ Plan changes will be assessed by the OQ Plan Administrator to determine if the change is necessary and all affected individuals will be notified as needed. The Administrator will bring any critical OQ Plan changes to the attention of the OQ Steering Committee.

A significant change may consist of, but is not limited to:

- Addition/deletion of covered tasks.
- Change in acceptable method of evaluation.
- Change in span of control.
- Change in frequency of qualification/evaluation.

Significant changes will be submitted to the PHMSA or the equivalent state agencies having jurisdiction over the facilities. Submittals will be made as necessary to the appropriate federal and state agencies.

9.4.2 OQ Steering Committee Review

Changes, which are OQ Plan or regulation-related, will be reviewed by the OQ Steering Committee. The recommended change will be assessed and action will be determined. If re-qualification is required, all affected individuals will be notified through their Evaluators/Supervisors.

Note: Interim procedures affecting covered tasks may also be initially directed by company Internal Incident/Accident Investigation Teams due to a DOT reportable incident/accident.

9.4.3 OQ Test Step Changes

Changes will be evaluated by the Administrator to determine if adjustments to OQ test steps are required. Any significant changes to OQ test steps will be brought to the OQ Steering Committee for review.

9.5 Change Management Form

All changes to the OQ plan and/or the OQ process as well as the method of communication are documented on the OQ Change Management form (Appendix E, Section #16.2).

9.6 Implementation of Changes

Evaluators/Supervisors are expected to implement the changes affecting them in their areas.

9.7 Changes Requiring Re-Qualification