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:	9/12/2011 / Kuang Chu	**Inspector/Submit Date:**	9/12/2011 / Kuang Chu
		Peer Review/Date:	
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Kinder Morgan Canada, Inc.	**OPID #:**	19585
Name of Unit(s):	Trans Mountain Pipeline (Puget Sound) LLC	**Unit #(s):**	285
Records Location:	Laurel Station	**Activity #**	
Unit Type & Commodity:	Hazardous liquid pipeline for crude oil transportation		
Inspection Type:	Standard	**Inspection Date(s):**	8/22 – 26/2011
PHMSA Representative(s):	Kuang Chu/UTC	**AFO Days:**	5

Company System Maps (copies for Region Files):	
Validate SMART Data (components, miles, etc): ☐	**Acquisition(s), Sale or New Construction**(submit SMART update): ☐
Validate Additional Requirements Resulting From Waiver(s) or Special Permit(s):	

Summary:

This inspection included a review of the records at the Laurel Station. The field facilities inspection included numerous sections of the pipeline right-of-way (ROW). A visit to the pipeline along the Manley Road. This area historically has low pipe-to-soil potential readings due to high soil resistivity associated with rocky terrain. All the CP test stations along the Manley Road were inspected and pipe-to-soil potential readings were taken. Several of the rectifiers along the pipeline were inspected. Most of the mainline valves were inspected and several manual valves were partially operated. The Laurel Station, Ferndale Station, Burlington Scraper Trap, and the Anacortes Meter Station were inspected. The breakout tanks T-170 & T-180 at the Laurel Station, T-130 at the Ferndale Station, and T-7 inside Shell Refinery in Anacortes were inspected.

Finding:

During the field inspection the pipe to soil potential readings taken at the mainline valve station MU-43 indicated that the pipe was most likely shorted with electrical conduits or other components. Post inspection notes: On September 8, 2011 the operator's technicians identified a ½" temperature probe as the source of the short. An insulating union has been ordered and will be installed within a week.

Probable Violation(s):
There was one probable violation for the 12" surge relief line to breakout tank T-7 inside Shell Refinery in Anacortes as noted below:

1. **§195.583 What must I do to monitor atmospheric corrosion control?**
   (b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

   Finding(s):
   During the field inspection of breakout tank T-7, it was noticed that the 12" pipe at soil-to-air interface had disbonded coating and there were signs of atmospheric corrosion at this location.

There was one item of concern as follows:
1. The annulus between the carrier pipe and the casing under I-5 freeway at ML-6 most likely was partially filled with water. The vent at one end of the casing was damaged by highway mowing crew and the opening of the casing allowed the water to get inside the casing.

During the review of the operator's O&M manual, the following deficiencies were found:

1. **§195.106 Internal design pressure**.
   (a) Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:

   P = (2 St/D) x E x F

   Findings: The Barlow's formula is not included in the operator's manual.

2. **§195.132 Aboveground breakout tank.**
   (a) Each aboveground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

   Findings: This requirement is not included in the operator's manual.

3. **§195.424 Pipe movement.**
   (a) No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure.

   Findings: This requirement is in operator's legacy manual (soon to be obsolete), but not in the new manual.

4. **§195.434 Signs.**
   Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

   Findings: Although the signs at the field facilities show the name of the operator and the emergency contact telephone number, the operator's manual does not have this requirement.

5. **§195.559 What coating material may I use for external corrosion control?**
Coating material for external corrosion control under Sec. 195.557 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 resist 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.

Findings: The requirements for coating material properties are not in the operator's manual.

6. **§195.561 When must I inspect pipe coating used for external corrosion control?**
(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.
(b) You must repair any coating damage discovered.

Findings: The requirement of (b) is not in operator's manual. However, it is in the legacy manual (soon to be obsolete).

7. **§195.563 Which pipelines must have cathodic protection?**
(a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

Findings: The requirement of having operational CP no later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable, is not in operator's manual.

8. **§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.

Findings: This requirement is not in operator's manual. The operator is currently using right-of-way (ROW) proximity form to document coating condition whenever the pipe is exposed along the pipeline ROW. A procedure and a new exposed pipe condition report form should be created for pipeline at any locations including ROW and facilities.

9. **§195.579 What must I do to mitigate internal corrosion?**

(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.

Findings: The requirement of (c) is not in operator's manual. However, it is in their legacy manual (soon to be obsolete).

10. **§195.583 What must I do to monitor atmospheric corrosion control?**

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

Findings: The location of spans over water is not in operator's manual. However, it is in their legacy manual (soon to be obsolete).

11. **§195.589 What corrosion control information do I have to maintain?**

(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.

(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.

(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.

Findings: The corrosion control records retention of at least 5 years is not in operator's manual.

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Name of Operator:	Kinder Morgan Canada, Inc		
OP ID No. [1]	19585	**Unit ID No.** [1]	285
HQ Address:		**System/Unit Name & Address:** [1]	
Suite 2700, Stock Exchange Building 300 5th Ave. SW Calgary, Alberta T2P5J2 Canada		Trans Mountain Pipeline (Puget Sound) LLC Laurel Station 1009 East Smith Road Bellingham, WA 98226	
Co. Official:	Hugh Harden, VP Operations & Engineering & EHS	**Activity Record ID No.:**	
Phone No.:	(403) 514-6400/(800) 535-7219	**Phone No.:**	(360) 398-1541
Fax No.:	(403) 514-6441	**Fax No.:**	(360) 398-7432
Emergency Phone No.:	(888) 876-6711	**Emergency Phone No.:**	(888) 876-6711

Persons Interviewed	Title	Phone No.
Patrick Davis	Supervisor, Corporation	(360) 398-1541
Adam Lind	Operations Engineer/Technical Services	(404) 514-6429

PHMSA Representative(s) [1]	Kuang Chu/UTC	**Inspection Date(s)** [1]	8/22 – 26/2011
Company System Maps (Copies for Region Files):			

Unit Description:
The pipeline system from the Canada-United States border supplies crude oil to the Conoco-Phillips refinery at Ferndale was constructed in 1954. The pumping capacity is provided by Sumas Pump Station in Canada and by the two new pumps built at the Laurel Station in 2008. In 1955, the pipeline was extended to Anacortes to supply crude oil to Shell and Tesoro refineries. In 1971, the pipeline system was extended to Cherry Point to supply crude oil to BP Cherry Point refinery. In total, 63.2 miles of pipeline was constructed in the State of Washington. The pipeline system can be broken down as follows:

- 15.3 miles of 20" pipeline between the Canada – US border to Laurel.
- 11.6 miles of 16" pipeline between Laurel Station and Ferndale Scraper Trap Station.
- 27.6 miles of 20" pipeline between Laurel Station and Burlington Scraper Trap Station.
- 9.0 miles of 16" pipeline between Burlington Scraper Trap Station and Anacortes Meter Station.

The 2008 system expansion added two 2,500 horsepower motor pumps along with reactivation of two 100,000 barrels breakout tanks at the Laurel Station. This system enhancement allows the flexibility to deliver crude oil to both Ferndale and Anacortes simultaneously. In addition to the Laurel Station expansion, a new meter station and a new 3,000 barrels relief tank were built at the Ferndale site in 2007.

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

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Portion of Unit Inspected: [1]

The field inspection included Laurel Station, Ferndale Station, Burlington Scraper Trap Station, and Anacortes Meter Station. Portions of the pipeline right-of-way and several mainline valves were inspected and some manual valves were partially operated. All the cathodic protection test stations on Manley Road were inspected and pipe-to-soil potentials were taken. The breakout tanks T-170 and T-180 at Laurel Station, T-130 at Ferndale Station, and T-7 inside Shell Refinery in Anacortes were inspected.

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 03/16/06 and 03/17/11.

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NPMS INFORMATION and UPDATE	Yes	No
Did the operator submit their pipeline information to NPMS and did they submit any updates or changes? 49 U.S.C. 60132 and ADB-08-07	x	

CONVERSION TO SERVICE		S	U	N/A	N/C
* .5	Operator has a written procedure that addresses all applicable requirements of **195.5.** Amt. 195-86 Pub. 06/09/06, eff. 07/10/06.	x			

REGULATED RURAL GATHERING LINES ***Notes: Kinder Morgan Canada (KMC) does not have regulated rural gathering lines.***		S	U	N/A	N/C
* **.11(a)**	Operator has identified pipelines that are Regulated Rural Gathering Lines that meet all of the following criteria: (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08). (1) nominal diameter from 6 5/8 inches to 8 5/8 inches; (2) located in or within one-quarter mile of a USA (3) operates at an MOP established under §195.406 that is: (i) greater than 20% SMYS; or (ii) if the stress level is unknown, or not steel; > 125 psig.			X	
* **.11(b)**	Operator has prepared written procedures to carry out the requirements of **195.11.** (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08). • Subpart B Reporting • Corrosion Control • Damage Prevention • Public Awareness • Establish MAOP • Line Markers • Operator Qualification			X	
* **.11(c)**	If a new USA is identified after July 3, 2008, the operator must implement the requirements in paragraphs (b)(2 - 8), and (b)(11) for affected pipelines within 6 months of identification. For steel pipelines, comply with the deadlines in paragraphs (b)(9 & 10). (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08).			X	
* **.11(d)**	Operator must maintain : (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08). (1) segment identification records required in paragraph (b)(1) of this section and the records required to comply with (b)(10) of this section, for the life of the pipe. (2) records necessary to demonstrate compliance (b)(2 – 9 & 11) of this section according to the record retention requirements of the referenced section or subpart.			X	

Comments:
Kinder Morgan Canada (KMC) does not have regulated rural gathering lines.

LOW-STRESS PIPELINES IN RURAL AREA ***Notes: Kinder Morgan Canada (KMC) does not have low-stress pipelines in rural area.***		S	U	N/A	N/C
* **.12(a)**	Operator has identified pipelines that are Regulated Low-stress Pipelines in Rural Areas that meet all of the following criteria: (except for those already covered by 49 CFR 195) (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08). (1) nominal diameter of 8 5/8 inches or more; and (2) located in or within one-half mile of a USA; and (3) operates at an MOP established under §195.406 that is: (i) greater than 20% SMYS; or (ii) if the stress level is unknown, or not steel; > 125 psig.			X	
* **.12(b)**	Operator has prepared written procedures to carry out the requirements of **195.12.** (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08). • Subpart B Reporting • Establish Integrity Management Plan • All Part 195 Safety Requirements			X	
*** .12 (c)**	Operator may notify PHMSA of economic burden. (Amt. Pub. 06/03/08 eff. 07/03/08).			X	
* **.12(d)**	If, after July 3, 2008, a new USA is identified, the operator must implement the requirements in paragraphs (b)(2)(i) for affected pipelines within 12 months of identification. (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08).			x	

* .12(d)	Operator must maintain: (Amt. 195-89, Pub. 06/03/08 eff. 07/03/08). (1) segment identification records required in paragraph (b)(1) for the life of the pipeline. (2) records necessary to demonstrate compliance (b)(2 - 4)according to the record retention requirements of the referenced section or subpart.			X	

Comments:
Kinder Morgan Canada (KMC) does not have low-stress pipelines in rural area.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
.402(a) .402(c)(2) *	.49	Complete and submit DOT Form PHMSA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year for each commodity, and each state a pipeline traverses by June 15 of each calendar year. *(NOTE: August 15, 2011 for the year 2010).* (Amdt. 195-95, 75 FR 72877, November 26, 2010, eff. 1/1/2011).	X			
	.50	Accident report criteria, as detailed under 195.50. A release that results in, **5 gallons** or more, **death or personal injury necessitating hospitalization**, an **explosion or fire not intentionally set by the operator,** 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) for additional requirements and exemptions for maintenance work under 5 BBLS).	X			
*	.52	Immediate notice to **NRC (800) 424-8802,** or electronically at **http://www.nrc.uscg.mil,** of certain events, and additional report if significant new information becomes available. Operator must have a written procedure for calculating an initial estimate of the amount of product released in an accident. (Amdt. 195-95, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	X			
*	.54(a)	Accident Report - file as soon as practicable, but no later than 30 days after discovery. Submittal must be electronically to **http://pipelineonlinereporting.phmsa.dot.gov** (Amdt. 195-95, 75 FR 72878, November 26, 2010).	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)	SRC Report requirements, including corrective actions (taken and planned)	X			
*	.58	Reports (except SRCR and offshore pipeline condition reports) must be submitted electronically to PHMSA at **http://opsweb.phmsa.dot.gov** unless an alternative reporting method is authorized IAW with paragraph (d) of this section. (Amdt. 195-95, 75 FR 72878, Nov. 26, 2010, eff. 1/1/2011).	X			
*	.64	Each operator must obtain an OPID, validate its OPIDs, and notify PHMSA of certain events at **http://opsweb.phmsa.dot.gov** (Amdt. 195-95, 75 FR 72878, Nov.26, 2010, eff. 1/1/2011).	X			

Comments:

		SUBPART C – INTERNAL DESIGN PRESSURE PROCEDURES	S	U	N/A	N/C
.402(c)/ .422	.106	Internal design pressure for pipe in a pipeline is determined in accordance with the requirements of this section and the formula: $P = (2\ St/D) \times E \times F$.		X		

Comments:
The Barlow's formula needs to be included in operator's manual.

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

Comments:

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 IAW API 1104 or Section IX of ASME BPVC?	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 (20th edition 2007, including errata 2008)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2007 edition, July 1, 2007)**, except that a welder qualified under an earlier edition than currently listed in **195.3** may weld, but may not requalify under that earlier edition. (Amdt 195-94 Pub. 8/11/10 eff. 10/01/10).	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			
Alert Notice 3/24/10		In the welding of pipe and fittings, do the operator's procedures give consideration to girth weld bevels being properly transitioned and aligned, girth weld pipe ends meeting API 5L pipe end diameter and diameter out-of-roundness specifications, and API 1104 alignment and allowable ``high-low" criteria, particularly in large diameter pipe (> 20" diameter)?				
	.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 **API 1104** and as per **195.228(b)** 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			
	Repair or Removal of Weld Defect Procedures					
	.230	Welds that are unacceptable must be removed and/or repaired. See **.228** and **.230** for exceptions.	X			

Comments:

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		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			
	.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. *Note: (An operator that elected to follow a risk-based alternative must have developed plans that included the method of testing and a schedule for the testing by December 7, 1998. The compliance deadlines for completion of testing are as shown in the table in §195.303, and in no case was testing to be completed later than 12/07/2004).*				
		Have all 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)?** ***<u>Notes: All pipelines have been pressure tested.</u>***			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:

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

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)	Determining 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)	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**. ***(Notes: The operator's pipelines are equipped to fail safe.)***			X	
	.402(c)(9)	Facilities not equipped to fail safe 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. ***(Notes: The operator's pipelines are equipped to fail safe.)***			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			
	.402(c)(15)	Implementing the applicable control room management procedures required by **195.446.** (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010). ***(Notes: This will be inspected later by a team from PHMSA.)***				X

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

Comments:

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)			S	U	N/A	N/C
.402(a)	.402(d)	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:

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 operator, fire, police, or other, and notifying appropriate operator personnel for response?	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 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			
*	.402(e)(10)	Actions to be taken by a controller during an emergency in accordance with **195.446.** (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010).	X			

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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:

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:

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, operator shall operate a pipeline above the MOP, and 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 under §§195.302 (b)(1) and (b)(2)(i) that has not been tested under **Subpart E**.	X			
	.406(b)	Operator shall not permit the pressure in a pipeline during surges or other variations from normal operations to exceed **110% of the MOP**.	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			

Comments:

STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

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.)			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.			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:				
	.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.			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.			X	
	.57	Offshore pipeline condition reports - must be filed within 60 days after the inspections			X	

Comments:
There are no offshore pipelines.

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:

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**. ***(Notes: This requirement is not in the O&M manual.)***		X		
	.424(b)	For **HVL** lines **joined** by welding, the operator must: ***(Notes: There are no HVL pipelines in this inspection unit.)***				
	.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:
There are no HVL pipelines in this unit.

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:

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. ***(Notes: There are no HVL pipelines in this inspection unit.)***			X	
	.428(b)	Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**. ***(Notes: There are no HVL pipelines in this inspection unit.)***			X	

		OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C
*	.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:

			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			
*	.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 (3rd edition December 2001, includes addendum 1 (September 2003), addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)**. 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, whichever 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. ***(Notes: The operator does not have breakout tanks built to API 2510 in this unit.)***			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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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. 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:
The requirement of signs must contain name of the operator and a telephone number is not in the O&M manual.

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:

PUBLIC AWARENESS PROGRAM PROCEDURES (In accordance with API RP 1162)				S	U	N/A	N/C
.402(a)	.440	Public Awareness Program in accordance with API RP 1162, (1st edition December 2003)					
	.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:					
		(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.		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.		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.		X			
	.440(i)	IAW API RP 1162, the operator's program should be reviewed for effectiveness within four years of the date the operator's program was first completed. For operators in existence on June 20, 2005, who must have completed their written programs no later than June 20, 2006, the first evaluation is due no later than **June 20, 2010**.		X			

Comments:

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			
	.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) *	.134	Each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of **API 1130, (3rd Edition, September 2007)** in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system. (Amdt 195-94 Pub. 75 FR 48593 8/11/10 eff. 10/01/10).	X			
*	.444	If a CPM system is installed, operator's procedures for the CPM leak detection system shall comply with **API 1130, (3rd Edition, September 2007)** in operating, maintaining, testing, record keeping, and dispatching training. (Amdt 195-94, 75 FR 48593 Pub. 8/11/10 eff. 10/01/10).	X			

Comments:

*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
.402(a)	.446	This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system.				
	.446(a)	Operator must develop written procedures no later than August 1, 2011, and implement the procedures no later than February 1, 2013. Amdt. 195-93 Pub. 12/03/09 eff. 02/01/10,				X

*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
	.446(b)	Operator must define roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions including: (1) When making decisions and taking actions during normal operations; (2) When an abnormal operating condition is detected; (3) During an emergency; (4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.				X
	.446(c)(1)	Operator must implement **API RP 1165, (1st Edition, January 2007)** (incorporated by reference, *see* § 195.3) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used.				X
	.446(c)(2)	Operator must conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays.				X
	.446(c)(3)	Operator must test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, once each calendar year, NTE 15 months.				X
	.446(c)(4)	Operator must test any backup SCADA systems once each calendar year, NTE 15 months.				X
	.446(c)(5)	Operator must implement section 5 of **API RP 1168, (1st Edition, September 2008)** (incorporated by reference, *see* § 195.3) to establish procedures for when a different controller assumes responsibility, including the content of information to be exchanged.				X
	.446(d)	Operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the defined roles and responsibilities:				
		(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep; (2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue; (3) Train controllers and supervisors to recognize the effects of fatigue; and (4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.				X
	.446 (e)	If a SCADA system is used, operator must have a written **Alarm Management Plan** including the following provisions to:				
		(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations; (2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities; (3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and once each calendar year, NTE 15 months; (4) Review the alarm management plan required by this paragraph once each calendar year, NTE 15 months, to determine the effectiveness of the plan; (5) Monitor the content and volume of general activity being directed to and required of each controller once each calendar year, NTE 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and (6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.				X
	.446 (f)	Assure changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:				
		(1) Implement section 7 of API RP 1168 for control room management change and require coordination between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration; and (2) Require field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations.				X
	.446 (g)	Assure lessons learned from operating experience are incorporated, as appropriate, into control room management procedures by performing each of the following:				

*		**CONTROL ROOM MANAGEMENT PROCEDURES** (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	**S**	**U**	**N/A**	**N/C**
		(1) Review accidents that must be reported pursuant to § 195.50 and 195.52 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to: (i) Controller fatigue; (ii) Field equipment; (iii) The operation of any relief device; (iv) Procedures; (v) SCADA system configuration; and (vi) SCADA system performance. (2) Include lessons learned from the operator's experience in the training program required by this section.				X
	.446 (h)	Operator must establish a controller training program to provide for training each controller to carry out the roles and responsibilities defined by the operator and review the training program content to identify potential improvements once each calendar year, NTE 15 months.				X
	.446(h)	An operator's controller training program must include the following elements:				
		(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence; (2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions; (3) Training controllers on their responsibilities for communication under the operator's emergency response procedures; (4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and (5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.				X

Comments: According to Huy Nguyen of PHMSA Western Region, a specialized inspection for CRM will be conducted by PHMSA later. All the items are marked N/C.

	PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES
.452	This form does not cover Liquid Pipeline Integrity Management Programs

	SUBPART G - OPERATOR QUALIFICATION PROCEDURES
.501 - .509	Operator Qualification Inspection – Use PHMSA Form # 14 as applicable

		SUBPART H - CORROSION CONTROL PROCEDURES	**S**	**U**	**N/A**	**N/C**
.402(c)(3)	**.555**	Procedures require 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 :				
	.557(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			
	.557(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. ***(Notes: There is no conversion to service in this unit.)***			X	

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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. ***(Notes: These requirements are not in the O&M manual.)***		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			
	.561(b)	All coating damage discovered must be repaired. ***(Notes: This requirement is not in the O&M manual.)***		X		
	.563(a)	Cathodic protection is applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**. ***(Notes: This requirement is not in the O&M manual.)***		X		
	.563(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. ***(Notes: There is no conversion to service in this unit.)***			X	
	.563(c)	All other buried or submerged pipelines that have an effective external coating must have cathodic protection.	X			
	.563(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. ***(Notes:***	X			
	.563(e)	Unprotected pipe must have cathodic protection if required by **195.573(b)**. ***(Notes: There is no unprotected pipe in this unit.)***			X	
*	.567	Test leads installation and maintenance.	X			
	.569	Examination of Exposed Portions of Buried Pipelines. ***(Notes: A procedure and a form for exposed pipe condition report should be developed by the operator.)***		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 RP0169-2007** (incorporated by reference). Amdt 195-94, 75 FR 48593, Pub. 8/11/10 eff. 10/01/10.	X			
	.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)**.	X			
		(2) **Identify not more than 2 years** after cathodic protection is installed, 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 SP 0169-2007.** Amdt 195-94, 75 FR 48593 Pub. 8/11/10 eff. 10/01/10.	X			
	.573(b)	Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
	.573(b) (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			
	.573(b) (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**. ***(Notes: There are no unprotected pipe.)***			X	
	.573(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			
	.573(e)	Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.	X			
	.575(a)	Procedures to electrically isolate each buried or submerged pipeline from other metallic structures, unless electrically interconnected and cathodically protected as a single unit.	X			
	.575(b)	Procedures to install insulating device(s) for electrical isolation of a portion of a pipeline.	X			
	.575(c)	Procedures to inspect and electrically test each electrical isolation and correct deficiencies identified in electrical isolation, such as shorted casings in accordance with **.573(e)**?	X			

		SUBPART H - CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.577(a)	For pipelines exposed to stray currents, is there a program to minimize the detrimental effects.	X			
	.577(b)	Design and install CP systems system to minimize any adverse effects on existing adjacent metallic structures.	X			
	.579(a)	For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, have corrosive effects been investigated and adequate steps taken?	X			
	.579(b) (1)	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. ***(Notes: This unit does not use corrosion inhibitors.)***			X	
	.579(b) (3)	Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7½ months.** ***(Notes: This unit does not use corrosion coupons.)***			X	
	.579(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. ***(Notes: This requirement needs to be included in the O&M manual.)***		X		
	.581(a)	Except pipelines meeting the requirements of .581(c), procedures to clean and coat pipelines that are exposed to the atmosphere.	X			
	.581(b)	Coating material must be suitable for the prevention of atmospheric corrosion.	X			
	.581(c)	Except portions of pipelines in offshore splash zones or soil-to-air interfaces, procedures to demonstrate by test, investigation, or experience appropriate to the environment of the pipelines that are not protected from atmospheric corrosion, that corrosion will – (1) Only be a light surface oxide; or (2) Not affect the safe operation of the pipeline before the next scheduled inspection. ***(Notes: All exposed pipe is painted for protection from atmospheric corrosion.)***			X	
	.583(a)	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**.	X			
	.583(b)	Inspect pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. ***(Notes: The O&M manual shall include spans over water for inspection.)***		X		
	.583(c)	If atmospheric corrosion is found during an inspection, procedures for protection against the corrosion as per §195.581.	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			
	.585(b)	Are procedures in place to either reduce the **MOP**, or repair/replace if localized corrosion pitting has reduced the wall thickness?	X			
	.587	Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, or RSTRENG)?**	X			
	.589	Corrosion Control Records Retention (Some are required for **5 yrs**) (Note - §§195.569, 195.573(a & b), and 195.579(b)(3) & (c) for the life of the pipeline). ***(Notes: This requirement shall be included in the O&M manual.)***		X		

Comments:

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	X			
.436	Security - Pumping Stations	X			
.438	No Smoking Signs	X			
.446	Control Room(s) ***(Notes: The Control Room is in Calgary and the inspection will be conducted by PHMSA later.)***				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.) ***(Notes: The soil/air interface of the 16" relief line to breakout tank T-7 inside Shell Refinery in Anacortes appeared to have atmospheric corrosion.)***		X		

Comments:

	PART 195 - PERFORMANCE AND RECORDS REVIEW	S	U	N/A	N/C
	CONVERSION OF SERVICE *(Notes: There was no conversion of service in this unit.)*				
.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	
	OUTER CONTINENTAL SHELF PIPELINES				
.9	Operator has identified on pipeline(s) [or if subsea - on a schematic] the specific point(s) at which operating responsibility transfers to a producing operator.			X	
	REPORTING				
.48 / .49	Annual Report (by commodity, by state)	X			
.52	Immediate Notice Reports to NRC (800-424-8802/or Online) and Supplemental NRC Reports *(Notes: There were no reports to NRC during this inspection period.)*			X	
.54(a)	Accident Reports (DOT Form 7000-1) (Must be submitted electronically after 01/01/2011) *(Notes: There were no accident reports during this inspection period.)*			X	
.54 (b)	Supplemental Accident Reports (DOT Form 7000-1) *(Notes: There were no supplemental accident reports during this inspection period.)*			X	
.56	Safety Related Conditions *(Notes: There were no safety related conditions during this inspection period.)*			X	
.57	Offshore Pipeline Condition Reports *(Notes: There are no offshore pipelines in this unit.)*			X	
.59	Abandoned Underwater Facility Reports *(Notes: There were no abandoned underwater facilities in this unit.)*			X	
	CONSTRUCTION *(Notes: There were no constructions during this inspection period.)*				
.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				
.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			
.310	Pipeline Test Record	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 ***(Notes: There was no 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 ***(Notes: There were no such events.)***			X	
.402(e)(9)	Post-Accident Reviews ***(Notes: There were no such events.)***			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) ***(Notes: There were no pipe repairs.)***			X	
.404(c)(2)	Repairs to Parts of the System other than pipe (maintain for at least 1 yr.) ***(Notes: There were no repairs to parts of the system other than pipe.)***			X	
.404(c)(3)	Required inspection and test records (maintain 2 yrs or next test/inspection)	X			
.406(a)	Establishing the MOP	X			
.407(b)	Refer to PHMSA Form # 15 to document review of operator's employee covered task records				
.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			
.430	Inspection of Fire Fighting Equipment	X			
.432	Inspection of Breakout Tanks (**1 per yr/15 months** or per **API 510 or 653**).	X			

Comments:

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	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.).	X			

API RP 1162 Baseline* Recommended Message Delivery Frequencies	
Stakeholder Audience (Hazardous Liquid Operators)	**Baseline Message Frequency**
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.

.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			
.440(i)	Effectiveness Review of operator's 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			

Comments:

	CORROSION CONTROL (Corrosion Control Records are required by .589(c))				
.555	Supervisors maintain thorough knowledge of corrosion procedures.	X			
.567	Test Lead Maintenance, frequent enough intervals	X			
.569	Inspection of Exposed Buried Pipelines (External Corrosion)	X			
.573(a)(1)	External Corrosion Control, Protected Pipelines Annual CP tests (**1 per yr/NTE 15 months**)	X			
.573(a)(2)	Close Interval surveys (meeting the circumstances determined by the operator)	X			
.573(b)	External Corrosion Control, Unprotected Pipeline Surveys, CP active corrosion areas **(1 per 3 cal yr/NTE 39 months)** ***(Notes: The pipeline system is coated and protected by CP.)***			X	
.573(c)	Interference Bonds, reverse current switches, diodes, rectifiers	X			
.573(e)	Corrective actions as required by .401(b) and, if IMP pipeline, 195.452(h).	X			
.575	Electrical isolation inspection, testing and monitoring (if applicable)	X			
.577	Testing for Interference Currents	X			
.579(a)	Corrosive effect investigation	X			
.579(b)	Examination of Coupons/Other Types of Internal Corrosion Monitoring Equipment **(2 per yr/NTE 7½ months)** ***(Notes: There are no coupons for the pipeline system.)***			X	
.579(c)	Inspection of Removed Pipe for Internal Corrosion ***(Notes: There were no cut-outs.)***			X	
.583(a)	Atmos. Corr. Monitoring **(1 per 3 cal yr/NTE 39 months onshore; 1 per yr/NTE 15 months offshore)**	X			
.585(a)	General Corrosion – Reduce MOP or repair ; ASME B31G or RSTRENG ***(Notes: There was no such occurrence.)***			X	
.585 (b)	Localized Corrosion Pitting – replace, repair, reduce MOP ***(Notes: There was no such occurrence.)***			X	
.589(a)&(b)	Cathodic Protection (Maps of anode location, test stations, CP systems, protected pipelines, etc.)	X			

Comments:

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	PHMSA Tracking Number:	587	Approval Date:	10/30/2007			
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

<u>OPA-1</u> - PHMSA 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 OPA-90 Plan, the answer is NO. Direct the operator to contact Melanie Barber, 202-366-4560.

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 (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 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.

Leave this list with the operator.

All PHMSA Advisory Bulletins (Last 2 years)

Number	Date	Subject
ADB-09-01	May 21, 2009	Pipeline Safety: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe
ADB-09-02	September 30, 2009	Pipeline Safety: Weldable Compression Coupling Installation
ADB-09-03	December 7, 2009	Pipeline Safety: Operator Qualification (OQ) Program Modifications
ADB-09-04	January 19, 2010	Pipeline Safety: Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-10-01	January 26, 2010	Pipeline Safety: Leak Detection on Hazardous Liquid Pipelines
ADB-10-02	February 3, 2010	Pipeline Safety - Implementation of Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-03	March 24, 2010	Pipeline Safety: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe
ADB-10-04	April 29, 2010	Pipeline Safety: Implementation of Electronic Filing for Recently Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-05	June 28, 2010	Pipeline Safety: Updating Facility Response Plans in Light of Deepwater Horizon Oil Spill
ADB-10-06	August 3, 2010	Pipeline Safety: Personal Electronic Device Related Distractions
ADB-10-08	November 3, 2010	Pipeline Safety: Emergency Preparedness Communications
ADB-11-01	January 4, 2011	Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation

For more PHMSA Advisory Bulletins, go to http://phmsa.dot.gov/pipeline/regs/advisory-bulletin