STANDARD INSPECTION REPORT OF A LIQUID PIPELINE CARRIER

A completed **Standard Inspection Checklist, Cover Letter and Field Report** are to be submitted to the Senior Engineer within **30 days** from completion of the inspection.

Inspection Report				
Docket Number	111555			
Inspector Name & Submit Date	Dennis Ritter, 10/14/2011			
Chief Eng Name/Review Date	Joe Subsits, 11/8/2011			
Operator Information				
Name of Operator:	Tidewater Terminal Co, Inc.		**OPID #:**	31051
Name of Unit(s):	Headquarters			
Records Location:	Snake River Terminal			
Date(s) of Last (unit) Inspection:	10/14/2011	**Inspection Date(s):**	September 15- October 14, 2011	

Inspection Summary:
This office review is to assess compliance with all applicable provisions of 49 CFR 195 and WAC 480-75 that pertain to Tidewater Terminal Company, Incorporated's (TTCI) Snake River Terminal. This inspection consists of a review of TTCI 's Operations and Maintenance Manual. In addition, the Manual references several other TTCI documents including the Operational Procedures & Policies Manual. As this manual has specific operating procedures affecting hazardous liquid pipeline facilities, it was included in this review.

Findings are as noted below.

HQ Address:		**System/Unit Name & Address:**	
P.O. Box 1210 6305 NW Old Lower River Rd Vancouver, WA 98660		671 Tank Farm Road Pasco, WA 99301	
Co. Official:		**Phone No.:**	
Phone No.:		**Fax No.:**	
Fax No.:		**Emergency Phone No.:**	
Emergency Phone No.:			

Persons Interviewed	Title	Phone No.

		CONVERSION TO SERVICE	S	U	N/A	N/C
1.	195.5	Has a written procedure been developed addressing all applicable requirements and followed?			X	

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REGULATED RURAL GATHERING LINES			S	U	N/A	N/C
2.	195.11	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	
3.	195.11(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	
4.	195.11(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	
5.	195.11(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:
1) Tidewater Terminal Company, Inc (TTCI) have not converted pipelines regulated under this part.
2-5) TTCI does not operate a regulated rural gathering line.

LOW-STRESS PIPELINES IN RURAL AREAS	S	U	N/A	N/C

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			S	U	N/A	N/C
6.	**195.12(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; (2) located in or within one-half 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	
7.	**195.12(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	
8.	**195.12(c)(1)**	Operator may notify PHMSA of economic burden. (Amt. Pub. 06/03/08 eff. 07/03/08).			X	
9.	**195.12(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	
10.	**195.12(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:
6-10) TTCI does not operate a regulated low-stress rural pipeline.

		SUBPART B - REPORTING PROCEDURES	S	U	N/A	N/C
11.		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). **.49**	X			
12.		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). **.50**	X			
13.	**195.402(a) 195.402(c)(2)**	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). **.52**		X		
14.		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). **.54(A)**		X		
15.		Supplemental report - required within 30 days of information change/addition **.54(b)**	X			
16.		Safety-related conditions (SRC) - criteria **.55**	X			
17.		SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery **.56(a)**	X			

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SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
18.		SCR Report requirements, including corrective actions (taken and planned) **.56(b)**	X			
19.	**195.402(a)** **195.402(c)(2)**	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		
20.		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		
		WAC 480-75 REPORTING PROCEDURES	**S**	**U**	**N/A**	**N/C**
21.	**480-75-610**	Reporting of proposed pipeline construction 45 days prior to construction	X			
22.	**480-75-620**	Providing notice of hydrotest to change MOP	X			
23.	**480-75-630**	Every company must give prompt telephonic notice to the **commission** within **two hours** of discovery.	X			
24.	**480-75-630(1)(e)**	Damage in excess of $25,000 (Include clean up, recovery, product loss) during the inspection period	X			
25.	**480-75-630(1)(g)**	Results in news media coverage	X			
26.	**480-75-630(2)**	Written reports within one month of the incident	X			
27.	**480-75-630(3)**	Notification within **24 hours** of emergency situations including emergency shutdowns, material defects or physical damage that impairs serviceability?	X			

Comments:
13) TTCI's Manual does not discuss how volume is calculated for a release event. There is not a procedure in TTCI's Operational Procedures & Policies Manual.
14, 19) The Manual does not address electronic filing of these documents.
20) The Manual does not reference an OPID.

SUBPART C – INTERNAL DESIGN PRESSURE PROCEDURES			S	U	N/A	N/C
28.	**195.402(c)** **195.422**	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) x E x F. **.106**	X			

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
29.	**195.402(c)** **195.422**	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 **.120(a)**	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.				

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		SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES	S	U	N/A	N/C
30.	195.402(c) 195.422	Welding must be performed by qualified welders using qualified welding procedures. **.214(a)**		X		
31.		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			
32.		Welding procedures must be qualified by destructive testing.	X			
33.		Each welding procedure must be recorded in detail including results of qualifying tests. **.214(b)**	X			
34.		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 re-qualify under that earlier edition. (Amdt 195-94 Pub. 8/11/10 eff. 10/01/10). **.222(a)**	X			
35.		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. **.222(b)**	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?				
	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)?				
36.	195.402(c) 195.422	Arc burns must be repaired. **.226(a)**	X			
37.		Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**. Pipe must be removed for non-repairable notches. **.226(b)**	X			
38.		The ground wire may not be welded to the pipe/fitting being welded. **.226(c)**	X			
		Nondestructive Testing Procedures				
39.	195.402(c) 195.422	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			
40.		Nondestructive testing of welds must be performed: **.234(b)**				
41.		1. In accordance with written procedures for **NDT**	X			
42.		2. By qualified personnel	X			
43.		3. By a process that will indicate any defects that may affect the integrity of the weld	X			
44.		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. **.266**	X			
		Repair or Removal of Weld Defect Procedures				
45.	195.402(c) 195.422	Welds that are unacceptable must be removed and/or repaired. See **.228** and **.230** for exceptions. **.230**	X			

Comments:
30) The AWS Standard Welding Procedures cited in the Manual (I assume these are TTCI's procedures, however they are not signed) prescribe an uphill direction of travel for the weld. The qualification documents for the individual welders indicate a downhill direction of travel. This needs to be resolved.
34) The Manual references Section 6 of API 1104 standard.
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SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C

		SUBPART E - PRESSURE TESTING PROCEDURES	S	U	N/A	N/C
46.		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). **.302(a)**	X			
47. 48. 49. 50.		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(c) - Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines). .302(b)(iii) - Carbon dioxide pipeline constructed before 07/12/91 that is located in a rural area as part of production field distribution system. .302(b)(2)(ii) - Any low-stress pipeline constructed before 8/11/1994, that does not transport HVL. .302(b)(3) - 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. .302(b)(4)/.303 ***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).*				
51.		Have pipelines <u>other than those described above</u> been pressure tested per Subpart E?			X	
52.		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	
53.	**195.402(c) 195.422 480-93-420**	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. **.304**	X			
54.		All pipe, all attached fittings, including components, must be pressure tested in accordance with **§195.302**. **.305(a)**	X			
55.		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. **.305(b)**	X			
56.		Appropriate test medium **.306**	X			
57.		Pipe associated with tie-ins must be pressure tested. **.308**	X			
58.		Test records must be retained for useful life of the facility. **.310(a)**	X			
		Does the record required by paragraph **(a)** of this section include: **.310(b)**				
59.		Pressure recording charts. **.310(b)(1)**	X			
60.		Test instrument calibration data. **.310(b)(2)**	X			
61.		Name of the operator, person responsible, test company used, if any. **.310(b)(3)**	X			
62.		Date and time of the test. **.310(b)(4)**	X			
63.		Minimum test pressure. **.310(b)(5)**	X			
64.		Test medium. **.310(b)(6)**	X			
65.		Description of the facility tested and the test apparatus. **.310(b)(7)**	X			
66.		Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts. **.310(b)(8)**	X			
67.		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)(9)**	X			

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SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
68.		Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03. **.310(b)(10)**	X			
69.		Signature of certifying agent. **WAC 480-75-420 (5)**	X			
70.		Beginning and ending times of the test. **WAC 480-75-420 (5)(c)**	X			
71.		Highest and lowest pressure achieved. **WAC 480-75-420 (5)(e)**	X			
72.		Is report submitted to the commission 45 days prior to a hydro test, if test was used to raise the MOP (after 9/26/02)? **WAC 480-75-620**		X		

Comments:
51-52) TTCI does not have any pipelines fitting this definition.
72) This information is not identified in the Manual or the written TTCI procedure TM-SRT-005

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES				S	U	N/A	N/C
73.	195.402(a)	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies? **.402**	X			
74.		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year?		X		
75.		c.	Appropriate parts must be kept at locations where O&M activities are conducted.	X			

Comments:
73) TTCI has prepared the Manual which addresses this regulation, however, all information is not available with this Manual—it is located in several other manuals which are referenced in section 104 of Manual.
74) TTCI has a provision in 201.1 to update the Manual annually, however, based on this review, it is apparent that the review does not do an adequate job of including appropriate code revisions.

SUBPART F - MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
	195.402(a)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for: **.402(c)**				
76.		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? **.402(c)(4)**	X			
77.		Analyzing pipeline accidents to determine their causes? **.402 (c)(5)**	X			
78.		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)(6)**	X			
79.		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)(7)**	X			
80.		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)(8)**	X			
81.		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)(9)**	X			
82.		Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards **.402(c)(10)**	X			

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SUBPART F - MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
83.		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per 195.59.			X	
84.		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)(11)**		X		
85.		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)(12)**	X			
86.		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)(13)**	X			
87.		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. **.402(c)(14)**	X			

Comments:
83) TTCI does not have pipelines regulated under this section.
84) The Manual does not specify which areas, if any, would meet this criteria for TTCI's operations.

MAINTENANCE & NORMAL OPERATION PROCEDURES CONT:			S	U	N/A	N/C
88.	.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). **.402(c)(15)**			X	
89.	480-75-300	Providing leak detection under flow and no flow conditions and including a procedure for responding to alarm		X		
90.	480-75-330	Responding to breakout tank overfill alarms	X			
91.	480-75-400	Backfilling pipe		X		
92.	480-75-410	Using a holiday detector to check coating condition prior to backfilling	X			
93.	480-75-460	100% Inspection of welds.	X			
94.	480-75-550	Reviewing change in class location for pipelines installed after 9/26/2003.		X		
95.	480-75-660(2)(a)(ii)	Providing a schedule of inspection and testing for mechanical and electrical components within the pipeline system		X		
96.	480-75-660(2)(a)(iii)	Describing the process for ensuring structural integrity of the pipeline by in-line inspections, hydro testing or other appropriate technique		X		
97.	480-75-660(2)(a)(iv)	Describing failsafe systems including emergency shutdown and isolation procedures		X		
98.	480-75-660(2)(a)(v)	Describing emergency management training for operators		X		
99.	480-75-660(2)(a)(vi)	Responding to earthquakes including threshold for line shutoff and restart procedures.		X		
100.	480-75-660(2)(a)(vii)	Assessing impacts on the pipeline system due to landslides.		X		

Comments:
88) TTCI does not have a control room
89) The Manual does not say whether the leak detection system can detect a leak within 15 minutes under no flow conditions per the WAC.
91) There was not a material specification for acceptable backfill.
94-100) These regulations were revised in 2008. The Manual needs to be revised to reflect the current regulations.

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

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		ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)	S	U	N/A	N/C
		Responding to, investigating, and correcting the cause of: **.402(d)(1)**				
101.		i. Unintended closure of valves or shutdowns?	X			
102.		ii. An increase or decrease in pressure or flow rate outside normal operating limits?	X			
103.		iii. Loss of communications?	X			
104.		iv. The operation of any safety device?	X			
105.		v. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property?	X			
106.		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)(2)**		X		
107.		Correcting variations from normal operation of pressure and flow equipment controls? **.402(d)(3)**	X			
108.		Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received? **.402(d)(4)**	X			
109.		Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found? **.402(d)(5)**	X			

Comments:
106) Specific critical locations are not identified in the Manual.

		EMERGENCY PROCEDURES	S	U	N/A	N/C
		The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for: **.402(e)**				
110.		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)(1)** **Note:** Including third-party damage	X			
111.	**195.402(a)**	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)(2)** **Note:** Including third party damage	X			
112.		Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency? **.402(e)(3)**	X			
113.		Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site? **.402(e)(4)**	X			
114.		Controlling the release of liquid at the failure site? **.402(e)(5)**	X			
115.		Minimizing the public **.402(e)(6)**exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.?	X			
116.	**195.402(a)**	Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**? **.402(e)(7)**		X		
117.		Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments? **.402(e)(8)**			X	
118.		Post accident review of employees activities to determine if procedures were effective and corrective action was taken? **.402(e)(9)**	X			
119.		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). **.402(e)(10)**			X	

Comments:

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Comments:
116) The Cross Reference in the Manual references Figure 502.1 to satisfy this part of the regulation, however, this figure could not be located. Additionally, there is no trigger as to when police or fire will be called.
117) TTCI does not transport HVLs or have them onsite.
119) TTCI does not have a control room.

		EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)	**S**	**U**	**N/A**	**N/C**
	195.402(a)	Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to: **.403(a)**				
120.		Carry out the emergency response procedures established under §195.402. **.403(a)(1)**	X			
121.		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)(2)**	X			
122.		Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions. **.403(a)(3)**	X			
123.		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)(4)**	X			
124.		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. **.403(a)(5)**		X		
125.		Instructions to enable O&M personnel to recognize and report potential safety related conditions. **.402(f)**	X			
		At intervals not exceeding 15 months, but at least once each calendar year: **.403(b)**				
126.		Review with personnel their performance in meeting the objectives of the emergency response training program **.403(b)(1)**	X			
127.		Make appropriate changes to the emergency response training program **.403(b)(2)**	X			
128.		Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible. **.403(c)**		X		

Comments:
124) Regulation states, ..."where feasible operator will simulate a pipeline emergency condition and incorporate into training." There is no reference in the O&M that this is feasible and has or has not been done.
128) The Manual does not detail how TTCI verifies that supervisors are maintaining appropriate knowledge of their area of responsibility for emergency response procedures.

		MAPS and RECORDS PROCEDURES	**S**	**U**	**N/A**	**N/C**
129.	195.402(a) & WAC 480-75-600	Making construction records, maps, and operating history available as necessary for safe operation and maintenance. **.402(c)(1)**	X			
		Each operator shall maintain current maps and records of its pipeline system that include at least the following information: **.404(a)** Updated within 6 months **480-75-600**				
		Location and identification of the following facilities: **.404(a)(1)**				
130.		i. Breakout tanks	X			
131.		ii. Pump stations	X			
132.		iii. Scraper and sphere facilities	X			
133.		iv. Pipeline valves	X			
134.		v. Facilities to which **§195.402(c)(9)** applies	X			
135.		vi. Rights-of-way	X			
136.		vii. Safety devices to which **§195.428** applies	X			
137.		All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines. **.404(a)(2)**	X			

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		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
138.		The maximum operating pressure of each pipeline. **.404(a)(3)**	X			
139.		The diameter, grade, type, and nominal wall thickness of all pipe. **.404(a)(4)**		X		
		Each operator shall maintain for at least **3 years** daily operating records for the following: **.404(b)**				
140.		The discharge pressure at each pump station. **.404(b)(1)**	X			
141.		Any emergency or abnormal operation to which the procedures under **§195.402** apply. **.404(b)(2)**	X			
		Each operator shall maintain the following records for the periods specified: **.404(c)**				
142.		The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**. **.404(c)(1)**	X			
143.		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)(2)**	X			
144.		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**. **.404(c)(3)**	X			

Comments:
139) The Manual references Appendix 300A to satisfy this portion of the regulation, however, it does not provide diameter, grade, type, and nominal wall thickness of pipe as required.

		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
	195.402(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following: **.406(a)**				
145.		The internal design pressure of the pipe determined by **§195.106**. Amt. 195-86 Pub. 06/09/06 eff. 07/10/06 **.406(a)(1)**	X			
146.		The design pressure of any other component on the pipeline. **.406(a)(2)**	X			
147.		**80%** of the test pressure **(Subpart E)**. **.406(a)(3)**			X	
148.		**80%** of the factory test pressure or of the prototype test pressure for any individual component. **.406(a)(4)**			X	
149.		**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(a)(5)**			X	
150.		The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations: **.406(b)**	X			
151.		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**.	X			

Comments:
147-149) The internal design pressure was determined per 195.406(a)(1).

		COMMUNICATION PROCEDURES (CONTROL CENTER)	S	U	N/A	N/C
152.	.402(a)	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system. **.408(a)**			X	
		Does the communication system required by paragraph **(a)** include means for: **.408(b)**				
153.		Monitoring operational data as required by **§195.402(c)(9)**. **.408(b)(1)**			X	
154.		Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions. **.408(b)(2)**			X	
155.		Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies. **.408(b)(3)**			X	

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COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
156.		Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster. **.408(b)(4)**			X	

Comments:
152-156) TTCI does not operate a control center.

LINE MARKER PROCEDURES			S	U	N/A	N/C
157.	**480-75-540**	Markers checked annually and replaced within 30 days	X			
158.	**195.402(a)**	Line markers must be placed over each buried pipeline in accordance with the following: **.410(a)**	X			
159.		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)(1)**	X			
160.		Must have the correct characteristics and information **.410(a)(2)**	X			
161.		Must be placed where pipelines are aboveground in areas that are accessible to the public **.410(c)**	X			

Comments:

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
162.	**480-75-540**	**Depth of Cover -** For pipelines constructed after 4/1/70, depth of cover surveys every five years or every three years for areas subject to erosion or subsoiling	X			
163.	**195.402(a)**	Operator must inspect the right-of-way weekly (unless weather impedes flyovers when applicable) **WAC 480-75-530**	X			
164.		Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 **years**. **.412(b)**			X	

Comments:
164) This regulation does not apply to this facility.

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
165.	**195.402(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.) **.413(a)**			X	
166.		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. **.413(b)**			X	
		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)**				
167.		Promptly, but no later than 24 hours after discovery, notify the NRC by phone. **.413(c)(1)**			X	

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UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
168.		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(c)(2)**			X	
169.		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. **.413(c)(3)**			X	
170.		Offshore pipeline condition reports - must be filed within 60 days after the inspections **.57**			X	

Comments:
165-179) This regulation does not apply to this facility.

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
171.	195.402(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(a)**	X			
172.		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(b)**	X			
173.		Operator must provide protection for each valve from unauthorized operation and from vandalism. **.420(c)**	X			

Comments:
171-172) Actual procedures are not in the Manual but located in Tidewater's Operational Procedures and Policy Manual.

PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
174.	WAC 480-75-440	Repairs made in accordance with **ASME B31.4**	X			
175.	195.402(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(a)**	X			
176.		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. **.422(b)**	X			

Comments:

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
177.	480-75-500	For evaluating pipe conditions during pipe movement including API 1117 stress calculations?	X			
178.	195.402(a)	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**. **.424(a)**	X			
		For **HVL** lines **joined** by welding, the operator must: **.424(b)**				
179.		Move the line when it does not contain **HVL**, unless impractical. **.424(b)(1)**	X			
180.		Have procedures under **§195.402** containing precautions to protect the public. **.424(b)(2)**	X			

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		PIPE MOVEMENT PROCEDURES	S	U	N/A	N/C
181.		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(b)(3)**	X			
		For **HVL** lines **not joined** by welding, the operator must: **.424(c)**				
182.		Move the line when it does not contain **HVL**, unless impractical. **.424(c)(1)**	X			
183.		Have procedures under **§195.402** containing precautions to protect the public. **.424(c)(2)**	X			
184.		Isolate the line to prevent flow of the **HVL**. **.424(c)(3)**	X			

Comments:

		SCRAPER and SPHERE FACILITY PROCEDURES	S	U	N/A	N/C
185.	195.402(a)	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres. **.426**	X			
186.		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
187.	195.402(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. **.428(a)**	X			
		Operator must inspect and test overpressure safety devices at the following intervals:				
188.		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year.	X			
189.		2. **HVL** pipelines at intervals not to exceed **7½ months**, but at least **twice** each calendar year.			X	
190.		Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**. **.428(b)**			X	
191.		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. **.428(c)**		X		
192.		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. **.428(d)**	X			

Comments:
189-190) TTCI does not transport HVLs.
191) It cannot be determined from the Manual whether this regulation applies to TTCI's regulated tanks as dates the tanks were put in service or significantly altered are not given or listed in Appendix 300A.

FIREFIGHTING EQUIPMENT PROCEDURES	S	U	N/A	N/C

FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
193.	195.402(a)	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas. **.430**	X			
		The equipment must be:				
194.		a. In proper operating condition at all times.	X			
195.		b. Plainly marked so that its identity as firefighting equipment is clear.	X			
196.		c. Located so that it is easily accessible during a fire.	X			

Comments:

BREAKOUT TANK PROCEDURES		
197.	195.402(a)	Utilize PHMSA Form #10 for all Breakout Tank Procedures

SIGN PROCEDURES				S	U	N/A	N/C
198.	.402(a)	.434	Operator must maintain signs visible to the public around each pumping station and breakout tank area.	X			
199.			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
200.	195.402(a)	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry. **.436**	X			

Comments:

SMOKING OR OPEN FLAME PROCEDURES			S	U	N/A	N/C
201.	195.402(a)	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. **.438**	X			

Comments:

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		PUBLIC AWARENESS PROGRAM PROCEDURES (Also in accordance with API RP 1162)	S	U	N/A	N/C
1.	192.402(a)	Public Awareness Program in accordance with API RP 1162, (1st **edition Dec-2003) .440**				
2.		The operators program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: **.440(d)**				
3.		(1) Use of a one-call notification system prior to excavation and other	X			
4.		(2) Possible hazards associated with unintended releases from a hazardous liquids or carbon dioxide pipeline facility;		X		
5.		(3) Physical indications of a possible release;		X		
6.		(4) Steps to be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release;		X		
7.		(5) Procedures to report such an event (to the operator).	X			
8.		Does program include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. **.440(e)**	X			
9.		The operator's program and the media used must be comprehensive enough to reach all areas the operator transports gas. **.440(f)**	X			
10.		Is the program conducted in English and any other languages commonly understood by a significant number of the population? **.440(g)**	X			
11.		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**. **.440(i)**		X		

Comments:
2) The Manual only describes how TTCI helps its excavators and other interested parties identify their pipe. The Manual does not indicate that TTCI has shared the hazards associated with the pipeline with those same parties.
3-4) Education does not specify if TTCI has notified potentially affected parties what to look for and what to do if a release occurs.
3) Call center is physically located in Vancouver, not Pasco.
11) The Manual does not indicate TTCI has complied with this regulation.

			DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API 1162)	S	U	N/A	N/C
202.	.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines?	X			
203.		.442(b)	Does the operator participate in a qualified One-Call program?	X			
204.		.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:				
205.			i. The program's existence and purpose.		X		
206.			ii. How to learn the location of underground pipelines before excavation activities are begun.		X		
207.		.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities.	X			
208.		.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			
209.		.442(c)(5)	Provide for marking of buried pipelines in the area of excavation activity within **2 business days**. **RCW 19.122**	X			
		.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
210.			i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.	X			
211.			ii. In the case of blasting, any inspection must include leakage surveys.	X			

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DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API 1162)				S	U	N/A	N/C
212.			Does the operator have directional drilling/boring procedures which include taking actions necessary to protect their facilities from the dangers posed by drilling and other trenchless technologies?		X		
			Does the operator review records of accidents and failures due to excavation damage to ensure causes of failures are addressed to minimize the possibility of reoccurrence?	X			
213.			**Damage Prevention (Operator Internal Performance Measures)**				
214.			Does the operator have a quality assurance program in place for monitoring the locating and marking of facilities? Do operators conduct regular field audits of the performance of locators/contractors and take action when necessary? (CGA Best Practices v. 6.0, Best Practice 4-18. Recommended only, not required)			X	
215.			Does operator including performance measures in facility locating services contracts with corresponding and meaningful incentives and penalties?			X	
216.			Do locate contractors address performance problems for persons performing locating services through mechanisms such as re-training, process change, or changes in staffing levels?			X	
217.			Does the operator periodically review the Operator Qualification plan criteria and methods used to qualify personnel to perform locates?			X	
218.			Review operator locating and excavation procedures for compliance with state law and regulations.			X	
219.			Are locates are being made within the timeframes required by state law and regulations? Examine record sample.			X	
220.			Are locating and excavating personnel properly qualified in accordance with the operator's Operator Qualification plan and with federal and state requirements?			X	

DAMAGE PREVENTION PROGAM PROCEDURES (State Requirements)		S	U	N/A	N/C
221.	Terminating the flow of hazardous liquid in pipeline immediately upon receiving information of third party damage. **RCW 19.122.035 (2)**	X			
222.	Has the pipeline company visually inspected the damaged pipeline **RCW 19.122.035 (2)**			X	
223.	Has the pipeline company determined if the damaged pipeline should be repaired or replaced **RCW 19.122.035 (2)**			X	

Comments: 204) The Manual does not specify excavation contractors who normally engage in excavation in this area.
205-206) No mention on informing public on intent to excavate
212) No specific boring/drilling procedures identified in the Manual
213-220) Not required for regulatory compliance.
222-223) No pipeline damage has occurred due to excavation contractor.

CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
224.	.402(a)	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). **.134**			X	
225.		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). **.444**			X	

Comments:
224) TTCI does not have a CPM leak detection system.

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		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	
	.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:				

CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)			S	U	N/A	N/C
		(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:				
		(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	

Required Submission of Data to the National Pipeline Mapping System Under the Pipeline Safety Improvement Act of 2002			S	U	N/A	N/C
	49 U.S.C. 60132, Subsection (b) ADB-08-07	Updates to NMPS: Operators are required to make update submissions every 12 months if any system modifications have occurred. Go to http://www.npms.phmsa.dot.gov/submission/ to review existing data on record. Also report no modifications if none have occurred since the last complete submission. Include operator contact information with all updates.		X		
	RCW 81.88.080	Pipeline Mapping System: Operator provides accurate maps (or updates) of pipelines, operating over two hundred fifty pounds per square inch gauge, to specifications developed by the commission sufficient to meet the needs of first responders?	X			

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Comments:
49 USC60132) The Manual does not state TTCI submits mapping updates annually (or reports "no modifications have occurred").

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 195.402(a)	S	U	N/A	N/C
226.		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? **.555**		X		
		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**				
227.		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			
228.		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			
229.		2) Is a segment that is relocated, replaced, or substantially altered?	X			
230.	**195.402(a)**	**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. **.559**	X			
231.		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			
232.		b. All coating damage discovered must be repaired.	X			
233.		a. Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**? **.563**	X			
		b. Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline-				
234.		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or	X			
235.		2) Is a segment that is relocated, replaced, or substantially altered?	X			
236.		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.	X			
237.		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	
238.		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.	X			
239.		Test leads installation and maintenance. **.567**	X			
240.		For placement of test stations at casing? **WAC 480-75-340**	X			
241.		Examination of Exposed Portions of Buried Pipelines. **.569**	X			
242.		Examination of pipe prior to backfilling. **WAC 480-75-520**	X			
243.		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. **.571**		X		
244.		Pipe to soil monitoring **(annually / 15months)**. **.573(a)**	X			
245.		(1) Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**.			X	

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		SUBPART H - CORROSION CONTROL PROCEDURES 195.402(a)	S	U	N/A	N/C
246.		(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		
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows;				
247.		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	
248.		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	
249.		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			
250.		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			
251.		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**.				
252.		Remediation of corrosion system deficiencies initiated within 90 days of discovery **WAC 480-75-510**	X			
253.		Are there adequate provisions for electrical isolations? **.575**	X			
254.		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. **.577**	X			
255.		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	
256.		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. **.579**			X	
257.		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7 ½ months.**			X	
258.		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			
259.		Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement). **.581(a)**	X			
		Atmospheric corrosion monitoring - **.583** **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**.				
260.		**(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.	X			
261.		**(c)** If atmospheric corrosion is found during an inspection, procedures for protection against the corrosion as per §195.581.	X			
262.		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? **.585(a)**	X			
263.		Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness? **.585(b)**	X			
264.		Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)? .587**	X			
265.		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). **.589**	X			

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Comments:
226) The Manual does not detail how TTCI verifies that supervisors are maintaining appropriate knowledge of their area of responsibility for corrosion control procedures.
238) No uncoated pipe.
243) There is a new NACE reference for this section. The Manual needs to be updated to new references and subsequent changes.
245) No uncoated pipe all cathodically protected.
246) There is a new NACE reference for this section. The Manual needs to be updated to new references and subsequent changes.
247-248) No uncoated pipe all cathodically protected
255-257) Do not transport corrosive materials.

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 Drug and Alcohol Program Check.				

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Oil Pollution Act (49 CFR 194)

Field Verification of Facility Response Plan Information			Y	N	N/A
266.	194.111	Is there a copy of the approved Facility Response Plan present? [See Guidance OPA-1]	X		
		RSPA Tracking Number: **FRP-WA-0045** Approval Date: March 14, 2008			
267.	194.107	Are the names and phone numbers on the notification list in the FRP current?[OPA-2]	X		
268.	194.107	Is there written proof of a contract with the primary oil spill removal organization (OSRO)? [OPA-3]	X		
269.	194.107	Are there complete records of the operator's oil spill exercise program? [OPA-4]	X		
270.	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):*

This section was included in the field inspection of June, 2011

OPA Inspection Guidance

OPA-1 - 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 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 (Last 2 years)

Leave this list with the operator.

Number	Date	Subject
ADB-09-01	May 21, 2009	Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe
ADB-09-03	Dec 7, 2009	Operator Qualification Program Modifications
ADB-09-04	Jan 14, 2010	Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-10-01	Jan 26, 2010	Pipeline Safety: Leak Detection on Hazardous Liquid Pipelines
ADB-10-02	Feb 3, 2010	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	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