Utilities and Transportation Commission
Standard Inspection Report for Intrastate Gas Transmission Pipelines
Form D - Records Review and Field Inspection

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

Inspection Report			
Inspection ID/Docket Number	2618		
Inspector Name & Submit Date	Lex Vinsel, 9/14/2012		
Chief Eng Name & Review Date	Joe Subsits, 9/17/2012		
Operator Information			
Name of Operator:	Puget Sound Energy	**OP ID #:**	22189
Name of Unit(s):	Transmission		
Records Location:	Tacoma, NSOB, Bellevue, See comments for addresses		
Date(s) of Last (unit) Inspection:	N/A	**Inspection Date(s):**	July 9-13,16-20,24-26,2012

Inspection Summary:

This inspection is to review the transmission segments of PSE pipeline.

HQ Address:	**System/Unit Name & Address:**
355 110TH Avenue NE Bellevue, WA 98004	
Co. Official: Sue McLain **Phone No.:** (425)462-3696 **Fax No.:** **Emergency Phone No.:** 800-552-7171	**Phone No.:** **Fax No.:** **Emergency Phone No.:**

Persons Interviewed	Title	Phone No.
Darryl Hong	Compliance Program Coordinator	(425)462-3911
Toni Imad	Consulting Engineer	(425)456-2970
Jerry Games	Engineering Assistant	(253)476-6224
Soon Dye	Senior Engineer	(425)462-3863
Signe Lipperts	Supervisor Maintenance Programs	(253)395-6830
Gary Swanson	Program Coordinator, Maintenance Programs	(206)517-3432
Stephanie Silva	Consulting Engineer	(425)462-3923
Derek Koo	Consulting Engineer	(425)462-3819
Don Frieze	Senior Engineering	(425)462-3862
Dan Koch	Manager Engineering	(425)462-3288
Cheryl McGrath	Manager of Gas Compliance & Regulatory Audits	(425)462-3207
Alan Mulkey	Consulting Engineer Gas System Integrity	(425)462-3889

UTC staff conducted abbreviated procedures inspection on 192 O&M and WAC items that changed since the last inspection. This checklist focuses on Records and Field items per a routine standard inspection.

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(check one below and enter appropriate date)			
☐	Team inspection was performed (Within the past five years.) or,	**Date:**	
☒	Other UTC Inspector reviewed the O & M Manual (Since the last yearly review of the manual by the operator.)	**Date:**	12/8/2010

GAS SYSTEM OPERATIONS			
Gas Supplier	Williams		
Number of reportable safety related conditions last year 0		Number of deferred leaks in system 0	
Number of non-reportable safety related conditions last year 0		Number of third party hits last year 0	
Miles of transmission pipeline within unit (total miles and miles in class 3 & 4 areas) 8 miles within distribution system			
Operating Pressure(s):		**MAOP (Within last year)**	**Actual Operating Pressure** (At time of Inspection)
Feeder:	Various	Various	
Town:			
Other:			
Does the operator have any transmission pipelines?	Yes		
Compressor stations? Use Attachment 4.	No		

Pipe Specifications:			
Year Installed (Range)	1960-2010	Pipe Diameters (Range)	6"-20"
Material Type	STW	Line Pipe Specification Used	API 5L
Mileage	8.37	SMYS %	28%
Supply Company	Williams – Cedar Hills	Class Locations	Not used

Integrity Management Field Validation

Important: Per PHMSA, IMP Field Verification Form 16 (Rev 3/19/2010) shall be used by the inspector as part of this standard inspection. When completed, the inspector will upload this information into the PHMSA IM Database (IMDB) located at http://primis.phmsa.dot.gov/gasimp/home.gim **Date Completed: Completed form 16 on 7/27/2011, see Docket #110030**

PART 199 DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES		S	U	NA	NC
Subparts A - C	Drug & Alcohol Testing & Misuse Prevention Program – Use PHMSA Form #13, Rev 3/19/2010. Do not ask the company to have a drug and alcohol expert available for this portion of your inspection. **See form #13 – PSE Snohomish Co. 2012**	X			

PART 192 Implement Applicable Control Room Management Procedures		S	U	NA	NC
.605(b)(12)	Implementing the applicable control room management procedures required by 192.631. (Amdt. 192- 112, 74 FR 63310, December 3, 2009, eff. 2/1/2010). **CRM inspection scheduled for 9/10/2012**				X

REPORTING RECORDS			S	U	N/A	N/C
1.	49 U.S.C. 60132, Subsection (b) ADB-08-07	**Submission of Data to the National Pipeline Mapping System Under the Pipeline Safety Improvement Act of 2002** 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. **Review 2011, 2010, 2009.**	X			

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REPORTING RECORDS			S	U	N/A	N/C
2.	RCW 81.88.080	Pipeline Mapping System: Has the operator provided 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? **Reviewed 2009-2011 submittals.**	X			
3.	191.5	Immediate Notice of certain incidents to **NRC (800) 424-8802,** or electronically at http://www.nrc.uscg.mil/nrchp.html, 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. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011). **None**			X	
4.	191.7	Reports (except SRCR and offshore pipeline condition reports) must be submitted electronically to PHMSA at https://opsweb.phmsa.dot.gov unless an alternative reporting method is authorized IAW with paragraph (d) of this section. (Amdt. 191-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011). **None**	X			
5.	191.15(a)	30-day follow-up written report (**Form 7100-2**) Submittal must be electronically to http://pipelineonlinereporting.phmsa.dot.gov (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011). **None for these segments.**	X			
6.	191.15(c)	Supplemental report (to 30-day follow-up) **None for these segments.**	X			
7.	191.17	Complete and submit DOT Form PHMSA F 7100-2.1 by March 15 of each calendar year for the preceding year. *(**NOTE**: June 15, 2011 for the year 2010).* (Amdt. 192-115, 75 FR 72878, November 26, 2010). **Annual report filed on time**	X			
8.	191.22	Each operator must obtain an OPID, validate its OPIDs, and notify PHMSA of certain events at https://opsweb.phmsa.dot.gov (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011). **Not required till September 30, 2012 per ADB-2012-04.**			X	
9.	191.23	Safety related condition reports **No safety related conditions for the transmission segments.**			X	
10.	191.25	Filing the SRCR within 5 days of determination, but not later than 10 days after discovery **No safety related conditions for the transmission segments.**			X	
11.	192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports **No abandoned facilities**			X	
12.	480-93-200(1)	Telephonic Reports to UTC **Pipeline Safety Incident Notification 1-888-321-9146** (Within **2 hours**) for events which **(regardless of cause)**;				
13.	480-93-200(1)(a)	Result in a fatality or personal injury requiring hospitalization;			X	
14.	480-93-200(1)(b)	Results in damage to property of the operator and others of a combined total exceeding fifty thousand dollars; **Note:** Report all damages regardless if claim was filed with pipeline company or not.			X	
15.	480-93-200(1)(c)	Results in the evacuation of a building, or high occupancy structures or areas;			X	
16.	480-93-200(1)(d)	Results in the unintentional ignition of gas;			X	
17.	480-93-200(1)(e)	Results in the unscheduled interruption of service furnished by any operator to twenty five or more distribution customers;			X	
18.	480-93-200(1)(f)	Results in a pipeline or system pressure exceeding the MAOP plus ten percent or the maximum pressure allowed by proximity considerations outlined in WAC 480-93-020;			X	
19.	480-93-200(1)(g)	Is significant, in the judgment of the operator, even though it does not meet the criteria of (a) through (e) of this subsection; or			X	
20.	480-93-200(2)	Telephonic Reports to UTC **Pipeline Safety Incident Notification 1-888-321-9146** (Within **24 hours**) for; **ID# 2134 overpressure of 6 PSIG on 400 MAOP segment.**	X			
21.	480-93-200(2)(a)	The uncontrolled release of gas for more than two hours;			X	
22.	480-93-200(2)(b)	The taking of a high pressure supply or transmission pipeline or a major distribution supply pipeline out of service;			X	
23.	480-93-200(2)(c)	A pipeline operating at low pressure dropping below the safe operating conditions of attached appliances and gas equipment; or			X	
24.	480-93-200(2)(d)	A pipeline pressure exceeding the MAOP **ID# 2134 overpressure of 6 PSIG on 400 MAOP segment.**	X			

Comments:

Comments

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Addresses for Records Locations

Main Office
355 110th Avenue NE
Bellevue WA

North Seattle Operating Base (NSOB)
1140 N. 94TH Street
Seattle Wa

Tacoma Office
38th Street

			S	U	N/A	N/C
25.	480-93-200(5)	Written incident reports (within 30 days) including the following;	**S**	**U**	**N/A**	**N/C**
26.	480-93-200(4)(a)	Name(s) and address(es) of any person or persons injured or killed, or whose property was damaged;	X			
27.	480-93-200(4)(b)	The extent of injuries and damage;	X			
28.	480-93-200(4)(c)	A description of the incident or hazardous condition including the date, time, and place, and reason why the incident occurred. If more than one reportable condition arises from a single incident, each must be included in the report;	X			
29.	480-93-200(4)(d)	A description of the gas pipeline involved in the incident or hazardous condition, the system operating pressure at that time, and the MAOP of the facilities involved;	X			
30.	480-93-200(4)(e)	The date and time the gas pipeline company was first notified of the incident;	X			
31.	480-93-200(4)(f)	The date and time the ((operators')) gas pipeline company's first responders arrived on-site;	X			
32.	480-93-200(4)(g)	The date and time the gas ((facility)) pipeline was made safe;	X			
33.	480-93-200(4)(h)	The date, time, and type of any temporary or permanent repair that was made;	X			
34.	480-93-200(4)(i)	The cost of the incident to the ((operator)) gas pipeline company;	X			
35.	480-93-200(4)(j)	Line type;	X			
36.	480-93-200(4)(k)	City and county of incident; and	X			
37.	480-93-200(4)(l)	Any other information deemed necessary by the commission.	X			
38.	480-93-200(5)	Submit a supplemental report if required information becomes available	X			
39.	480-93-200(6)	Written report within 45 days of receiving the failure analysis of any **incident or hazardous condition** due to **construction defects or material failure**	X			

Comments:

40.	480-93-200(7)	**Annual Reports** filed with the commission no later than **March 15** for the proceeding calendar year **Annual reports OK**	**S**	**U**	**N/A**	**N/C**
41.	480-93-200(7)(a)	A copy of PHMSA F-7100.1-1 and F-7100.2-1 annual report required by U.S. Department of Transportation, PHMSA/Office of Pipeline Safety **Turned in on time.**	X			
42.	480-93-200(7)(b)	Damage Prevention Statistics Report including the following; **Turned in March 7, 2012, before March 15 deadline.**	X			
43.	480-93-200(7)(b)(i)	Number of gas-related one-call locate requests completed in the field;**138028 system wide**	X			
44.	480-93-200(7)(b)(ii)	Number of third-party damages incurred; and **850 system wide**	X			

			S	U	N/A	N/C
45.	480-93-200(7)(b)(iii)	Cause of damage, where cause of damage is classified as **See damage prevention reports.** one of the following: (A) Inaccurate locate; (B) Failure to use reasonable care; (C) Excavated prior to a locate being conducted; or (D) Other	X			
46.	480-93-200(7)(c)	Reports detailing all construction defects and material failures resulting in leakage. Categorizing the different types of construction defects and material failures. The report must include the following: (i) Types and numbers of construction defects; and (ii) Types and numbers of material failures.	X			
47.	480-93-200(8)	Providing updated emergency contact information to the commission and appropriate officials of all municipalities where gas pipeline companies have facilities	X			
48.	480-93-200(9)	Providing by email, reports of daily construction and repair activities no later than 10:00 a.m.	X			
49.	480-93-200(10)	Submitting copy of DOT Drug and Alcohol Testing MIS Data Collection Form when required **OK**	X			

Comments:

		CONSTRUCTION RECORDS	S	U	N/A	N/C
50.	192.225	Test Results to Qualify Welding Procedures	X			
51.	192.227	Welder Qualification	X			
52.	192.241(a)	Visual Weld Inspector Training/Experience	X			
53.	192.243(b)(2)	Nondestructive Technician Qualification **CTS 2401 Welding**	X			
54.	192.243(c)	NDT procedures **Mag Particle procedures OK**	X			
55.	192.243(f)	Total Number of Girth Welds **2 per pumpkin, 4 total**	X			
56.	192.243(f)	Number of Welds Inspected by NDT **4 total**	X			
57.	192.243(f)	Number of Welds Rejected 0	X			
58.	192.243(f)	Disposition of each Weld Rejected **No welds rejected.**	X			
59.	480-93-080(1)(b)	Use of testing equipment to record and document essential variables **Yes**	X			
60.	480-93-115(2)	Test leads on casings (without vents) installed after 9/05/1992 **No casings without vents on transmission segments.**			X	
61.	480-93-115(3)	Sealing ends of casings or conduits on Transmission lines and main **casing installed during original construction 1968. Casing requirements only apply to casings after 1992.**			X	
62.	480-93-115(4)	Sealing ends (nearest building wall) of casings or conduits on services **(Not part of this inspection, refers to services only.)**			X	
63.	192.303	Construction Specifications **Reviewed repair and procedures. Reviewed construction specifications for all transmission sections. PSE is working on their response to ADB-2012-06 and rechecking ALL Transmission segments for verification of MAOP.**	X			
64.	192.325	Underground Clearance **Procedure 2525.1700, excavation and cover**	X			
65.	192.327	Amount, Location, Cover of each Size of Pipe Installed **Procedure 2525.1700, excavation and cover**	X			

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CONSTRUCTION RECORDS			S	U	N/A	N/C
66.	192.328	If the pipeline will be operated at the alternative MAOP standard calculated under 192.620 (80% SMYS) does it meet the additional construction requirements for: **PSE does not use this method.** • Quality assurance • Girth welds • Depth of cover • Initial strength testing, and; • Interference currents?			X	
67.	480-93-160(1)	Detailed report filed 45 days prior to construction or replacement of transmission pipelines ≥ 100 feet in length **No sections over 100 ft in length during time period.**	X			
68.	480-93-170(3)	Pressure Tests Performed on new and replacement pipelines **Reviewed pressure record for sleeve repair of section on N Midway Supply Repair. OK**	X			
69.	480-93-170(10)	Pressure Testing Equipment checked for Accuracy/Intervals (Manufacturers Recom or Operators schedule) **Spring dial indicator used for pressure testing. OK**	X			
70.	480-93-175(1)	Study prepared and approved prior to moving and lowering of metallic pipelines > 60 psig **No transmission segments have been moved or lowered.**			X	
71.	192.455	Cathodic Protection	X			

Comments:

OPERATIONS and MAINTENANCE RECORDS			S	U	N/A	N/C
72.	192.14	**Conversion To Service Performance and Records**				
73.	192.14 (a)(2)	Visual inspection of right of way, aboveground and selected underground segments **No conversion to service.**			X	
74.	192.14 (a)(3)	Correction of unsafe defects and conditions **No conversion to service.**			X	
75.	192.14 (a)(4)	Pipeline testing in accordance with Subpart J **No conversion to service.**			X	
76.	192.14 (b)	Pipeline records: investigations, tests, repairs, replacements, alterations (life of pipeline) **No conversion to service.**			X	
77.	192.16	Customer Notification (**Verification – 90 days – and Elements**) - **No services on INTRAstate Transmission Lines**			X	
78.	192.603(b)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**) .605(a) **Note:** Including review of OQ procedures as suggested by PHMSA - ADB-09-03 dated 2/7/09	X			
79.	192.603(b)	Abnormal Operations .605(c)	X			
80.	192.603(b)	Availability of construction records, maps, operating history to operating personnel .605(b)(3)	X			
81.	192.603(b)	Periodic review of personnel work – effectiveness of normal O&M procedures .605(b)(8)	X			
82.	192.603(b)	Periodic review of personnel work – effectiveness of abnormal operation procedures .605(c)(4)	X			
83.		**Damage Prevention Program**				
84.	192.603(b)	List of Current Excavators .614 (c)(1)	X			
85.	192.603(b)	Notification of Public/Excavators .614 (c)(2)	X			
86.	192.603(b)	Notifications of planned excavations. (One -Call Records) .614 (c)(3)	X			
87.	.614(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
88.		1. Is the inspection done as frequently as necessary during and after the activities to verify the integrity of the pipeline?	X			
89.		2. In the case of blasting, does the inspection include leakage surveys? (required)	X			
90.		**Damage Prevention (Operator Internal Performance Measures)**				

		OPERATIONS and MAINTENANCE RECORDS	S	U	N/A	N/C
91.	Does the pipeline operator voluntarily submit pipeline damage statistics into the UTC Damage Information Reporting Tool (DIRT)? Operator may register at https://identity.damagereporting.org/cgareg/control/login.do Y x N					
92.		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			
93.		Does operator including performance measures in facility locating services contracts with corresponding and meaningful incentives and penalties?	X			
94.		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			
95.		Does the operator periodically review the Operator Qualification plan criteria and methods used to qualify personnel to perform locates?	X			
96.		Review operator locating and excavation procedures for compliance with state law and regulations.	X			
97.		Are locates are being made within the timeframes required by state law and regulations? Examine record sample.	X			
98.	195.507(b)	Are locating and excavating personnel properly qualified in accordance with the operator's Operator Qualification plan and with federal and state requirements?	X			
99.	192.709	Class Location Study (**If Applicable**) .609	X			
100.	192.605(a)	Confirmation or revision of MAOP. Final Rule Pub. 10/17/08, eff. 12/22/08. .611	X			
101.	192.603(b)	Prompt and effective response to each type of emergency .615(a)(3) **Note:** Review operator records of previous accidents and failures including third-party damage and leak response	X			
102.	192.615	Actions required to be taken by a controller during an emergency in accordance with 192.631. (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010). .615(a)(11)	X			
103.	192.603(b)	Location Specific Emergency Plan .615(b)(1)	X			
104.	192.603(b)	Emergency Procedure training, verify effectiveness of training .615(b)(2)	X			
105.	192.603(b)	Employee Emergency activity review, determine if procedures were followed. .615(b)(3)	X			
106.	192.603(b)	Liaison Program with Public Officials .615(c)	X			

Comments:

		S	U	N/A	N/C
192.603(b)	**Public Awareness Program** .616				
	Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. See 192.616(a) and (j) for exceptions.				
	API RP 1162 Baseline* Recommended Message Deliveries				

		Stakeholder Audience (Natural Gas Transmission Line Operators) / **Baseline Message Frequency (starting from effective date of Plan)** Residents Along Right-of-Way and Places of Congregation: 2 years Emergency Officials: Annual Public Officials: 3 years Excavator and Contractors: Annual One-Call Centers: As required of One-Call Center * Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.				
107.		The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: .616(d) (1) Use of a one-call notification system prior to excavation and other damage prevention activities; (2) Possible hazards associated with the unintended release from a gas pipeline facility (3) Physical indications of a possible release; (4) Steps to be taken for public safety on the event of a gas pipeline release; and (5) Procedures to report such an event (to the operator).	X			
108. **109.**	192.603(b)	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.). .616 (e) & (f)	X			
110.		The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area. .616(g)	X			
111.		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**. .616(h) **Reviewed**	X			
112.		Analyzing accidents and failures including laboratory analysis where appropriate to determine cause and prevention of recurrence .617 **Note:** Including excavation damage (PHMSA area of emphasis)	X			

Comments:

113.	192.517	Pressure Testing	X			
114.	.553(b)	Uprating **No Uprating in Trans segments.**			X	
115.	192.709	**Maximum Allowable Operating Pressure (MAOP)**				
116.	.709	**Note: If the operator is operating at 80% SMYS with waivers, the inspector needs to review the special conditions of the waiver.**				
117.		MAOP cannot exceed the lowest of 0 the following: .619				
118.		Design pressure of the weakest element, .619(a)(1) Amdt, 192-103 pub. 06/09/06, eff. 07/10/06 **Pressure Test 192.619(a)(2)**			X	

<table>
<tr><td>119.</td><td></td><td>The highest actual operating pressure to which the segment of line was subjected during the 5 years preceding the applicable date in the second column, unless the segment was tested in according to .619(a)(2) after the applicable date in the third column or the segment was uprated according to subpart K. Amdt 192-102 pub. 3/15/06, eff. 04/14/06. For gathering line related compliance deadlines and additional gathering line requirements, refer to Part 192 including this amendment. .619(a)(3) Pressure Test 192.619(a)(2)
<table>
<tr><th>Pipeline segment</th><th>Pressure date</th><th>Test date</th></tr>
<tr><td>-Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006.</td><td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td><td>5 years preceding applicable date in second column.</td></tr>
<tr><td>Offshore gathering lines</td><td>July 1, 1976</td><td>July 1, 1971</td></tr>
<tr><td>All other pipelines</td><td>July 1, 1970</td><td>July 1, 1965</td></tr>
</table></td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>120.</td><td>.709</td><td>.619(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611. Amdt 192-102 pub. 3/15/06, eff. 04/14/06. For gathering line related compliance deadlines and additional gathering line requirements, refer to Part 192 including this amendment. Pressure Test 192.619(a)(2)</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>121.</td><td></td><td>.620 If the pipeline is designed to the alternative MAOP standard in 192.620 does it meet the additional design requirements for:
• General standards
• Fracture control
• Plate and seam quality
• Mill hydrostatic testing
• Coating
• Fittings and flanges
• Compressor stations Final rule pub. 10/17/08, eff. 12/22/08 No alternate MAOP</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>122.</td><td>480-93-015(1)</td><td>Odorization of Gas – Concentrations adequate</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>123.</td><td>480-93-015(2)</td><td>Monthly Odorant Sniff Testing</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>124.</td><td>480-93-015(3)</td><td>Prompt action taken to investigate and remediate odorant concentrations not meeting the minimum requirements</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>125.</td><td>480-93-015(4)</td><td>Odorant Testing Equipment Calibration/Intervals (Annually or Manufacturers Recommendation)</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>126.</td><td>480-93-124(3)</td><td>Pipeline markers attached to bridges or other spans inspected? 1/yr(15 months) Part of leak survey patrols.</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>127.</td><td>480-93-124(4)</td><td>Markers reported missing or damaged replaced within 45 days?</td><td>X</td><td></td><td></td><td></td></tr>
</table>

Comments:

128.	480-93-185(1)	Reported gas leaks investigated promptly/graded/record retained **None on transmission segments.**			X	
129.	480-93-185(3)	Leaks originating from a foreign source reported promptly/notification by mail/record retained **None on transmission segments.**			X	
130.	480-93-187	Gas Leak records **None on transmission segments.**			X	
131.	480-93-188(1)	Gas Leak surveys	X			
132.	480-93-188(2)	Gas detection instruments tested for accuracy/intervals (Mfct rec or monthly not to exceed 45 days)	X			

133.	480-93-188(3)	Leak survey frequency **(Refer to Table Below)**	X			

Business Districts (By 6/02/07)	1/yr (15 months)
High Occupancy Structures	**1/yr (15 months)**
Pipelines Operating ≥ 250 psig	**1/yr (15 months)**
Other Mains: CI, WI, copper, unprotected steel	**2/yr (7.5 months)**

134.	480-93-188(4)(a)	Special leak surveys - Prior to paving or resurfacing, following street alterations or repairs **None**			X	
135.	480-93-188(4)(b)	Special leak surveys - areas where substructure construction occurs adjacent to underground gas facilities, and damage could have occurred **None**			X	
136.	480-93-188(4)(c)	Special leak surveys - Unstable soil areas where active gas lines could be affected **None**			X	
137.	480-93-188(4)(d)	Special leak surveys - areas and at times of unusual activity, such as earthquake, floods, and explosions **None**			X	
138.	480-93-188(5)	Gas Survey Records	X			
139.	480-93-188(6)	Leak Survey Program/Self Audits	X			
140.	192.709	Patrolling (**Refer to Table Below**) .705	X			

Class Location	At Highway and Railroad Crossings	At All Other Places
1 and 2	**2/yr (7½ months)**	**1/yr (15 months)**
3	**4/yr (4½ months)**	**2/yr (7½ months)**
4	**4/yr (4½ months)**	**4/yr (4½ months)**

141.	192.709	Leak Surveys (**Refer to Table Below**) .706	X			

Class Location	Required	Not Exceed
1 and 2	**1/yr**	**15 months**
3	**2/yr**	**7½ months**
4	**4/yr**	**4½ months**

142.	192.605(b)	Abandoned Pipelines; Underwater Facility Reports .727(g) **None**			X	
143.	192.709	Compressor Station Relief Devices (**1 per yr/15 months**) .731(a) **No compressors**			X	
144.	192.709	Compressor Station Emergency Shutdown (**1 per yr/15 months**) .731(c) **No compressors**			X	
145.	192.709	Compressor Stations – Detection and Alarms (**Performance Test**) .736(c) **No compressors**			X	
146.	192.709	Pressure Limiting and Regulating Stations (**1 per yr/15 months**) .739	X			
147.	192.709	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**) .743 **Annual check**	X			

Comments:

148.	192.709	Valve Maintenance (**1 per yr/15 months**) .745 **Reviewed 7 HP Valve records for 2007-2011.**	X			
149.	192.709	Vault Maintenance (≥**200 cubic feet**)(**1 per yr/15 months**) .749 **None**			X	
150.	192.603(b)	Prevention of Accidental Ignition (hot work permits) .751	X			

151.	192.603(b)	Welding – Procedure .225(b)	X			
152.	192.603(b)	Welding – Welder Qualification .227/.229	X			
153.	192.603(b)	NDT – NDT Personnel Qualification .243(b)(2)	X			
154.	192.709	NDT Records (**Pipeline Life**) .243(f)	X			
155.	192.709	Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**)	X			
156.	.807(b)	Refer to PHMSA Form # 15 to document review of operator's employee covered task records	X			
157.	192.905(c)	Periodically examining their transmission line routes for the appearance of newly identified area's (HCA's) b **PSE does it annually. Reviewed maps and patrol records.**	X			

Comments:

Item 157 – HCA patrols 7500.2000 patrolling records for year.

CORROSION CONTROL RECORDS			**S**	**U**	**N/A**	**N/C**
158.	192.453	CP procedures (system design, installation, operation, and maintenance) must be carried out by qualified personnel	X			
159.	192.455(a)(2)	CP system installed on and operating within 1 yr of completion of pipeline construction *(after 7/31/71)*	X			
160.	192.491	Annual Pipe-to-soil Monitoring (**1 per yr/15 months**) for short sections (**10% per year; all in 10 years**) .465(a)	X			
161.	192.491	Maps or Records .491(a)	X			
162.	192.491	Examination of Buried Pipe when Exposed .459	X			
163.	480-93-110(8)	CP test reading on all exposed facilities where coating has been removed	X			
164.	192.491	Rectifier Monitoring (**6 per yr/2½ months**) .465(b)	X			
165.	192.491	Interference Bond Monitoring – Critical (**6 per yr/2½ months**) .465(c)	X			
166.	192.491	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**) .465(c)	X			
167.	192.491	Prompt Remedial Actions .465(d)	X			
168.	192.491	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) .465(e) **None on Transmission Segments**			X	
169.	192.491	Electrical Isolation (**Including Casings**) .467	X			
170.	480-93-110(2)	Remedial action taken within 90 days (Up to 30 additional days if other circumstances. Must document) .465(d)	X			
171.	480-93-110(3)	CP Test Equipment and Instruments checked for Accuracy/Intervals (Mfct Rec or Opr Sched)	X			
172.	480-93-110(5)	Casings inspected/tested annually not to exceed fifteen months	X			
173.	480-93-110(5)(a)	Casings w/no test leads installed prior to 9/05/1992. Demonstrate other acceptable test methods	X			
174.	480-93-110(5)(b)	Possible shorted conditions – Perform confirmatory follow-up inspection within 90 days	X			
175.	480-93-110(5)(c)	Casing shorts cleared when practical	X			
176.	480-93-110(5)(d)	Shorted conditions leak surveyed within 90 days of discovery. Twice annually/7.5 months	X			
177.	192.491	Interference Currents .473	X			
178.	192.491	Internal Corrosion; Corrosive Gas Investigation .475(a)	X			
179.	192.491	Internal Corrosion; Internal Surface Inspection; Pipe Replacement .475(b)	X			
180.	192.491	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems .476(d)	X			
181.	192.491	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**) .477 **No coupons**			X	

Utilities and Transportation Commission
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Form D - Records Review and Field Inspection

CORROSION CONTROL RECORDS			S	U	N/A	N/C
182.	192.491	Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**) .481	X			
183.	192.491	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions .483/.485	X			

Comments:

PIPELINE INSPECTION (Field)			S	U	N/A	N/C
184.	192.161	Supports and anchors	X			
185.	192.179	Valve Protection from Tampering or Damage	X			
186.	480-93-015(1)	Odorization levels	X			
187.	192.463	Levels of Cathodic Protection	X			
188.	192.465	Rectifiers	X			
189.	192.467	CP - Electrical Isolation	X			
190.	192.469	Test Stations (Sufficient Number)	X			
191.	192.476	Systems designed to reduce internal corrosion	X			
192.	192.479	Pipeline Components Exposed to the Atmosphere	X			
193.	192.481	Atmospheric Corrosion - monitoring	X			
194.	480-93-115(2)	Casings – Test Leads (Casings w/o vents installed after 9/05/1992)	X			
195.	192.605	Knowledge of Operating Personnel	X			
196.	613(b), .703	Pipeline condition, unsatisfactory conditions, hazards, etc.	X			
197.	480-93-124	Pipeline Markers, Road and Railroad Crossings	X			
198.	192.719	Pre-pressure Tested Pipe (**Markings and Inventory**)	X			
199.	192.739	Pressure Limiting and Regulating Devices (**Mechanical**) (spot-check field installed equipment vs. inspection records)	X			
200.	192.743	Pressure Limiting and Regulating Devices (**Capacities**) (spot-check field installed equipment vs. inspection records)	X			
201.	192.745	Valve Maintenance	X			
202.	192.751	Warning Signs Posted	X			
203.	192.801 - 192.809	Operator qualification questions – Refer to OQ Field Inspection Protocol Form	X			

Operator Qualification Field Validation

Important: Per PHMSA, the OQ Field Inspection Protocol Form 15 (Rev 3, Feb 08) shall be used by the inspector as part of this standard inspection. When completed, the inspector will upload this information into the PHMSA OQ Database (OQDB) located at http://primis.phmsa.dot.gov/oqdb/home.oq **Date Form Upload Completed: 09/14/2012 by LV**

Comments:

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COMPRESSOR STATIONS INSPECTION(NO COMPRESSOR STATIONS) (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c)		S	U	N/A	N/C
.163 (c)	Main operating floor must have (at least) two (2) separate and unobstructed exits			X	
	Door latch must open from inside without a key			X	
	Doors must swing outward			X	
(d)	Each fence around a compressor station must have (at least) 2 gates or other facilities for emergency exit			X	
	Each gate located within 200 ft of any compressor plant building must open outward			X	
	When occupied, the door must be opened from the inside without a key			X	
(e)	Does the equipment and wiring within compressor stations conform to the **National Electric Code, ANSI/NFPA 70?**			X	
.165(a)	If applicable, are there liquid separator(s) on the intake to the compressors?			X	
.165(b)	Do the liquid separators have a manual means of removing liquids?			X	
	If slugs of liquid could be carried into the compressors, are there automatic dumps on the separators, Automatic compressor shutdown devices, or high liquid level alarms?			X	
.167(a)	ESD system must:				
	- Discharge blowdown gas to a safe location			X	
	- Block and blowdown the gas in the station			X	
	- Shut down gas compressing equipment, gas fires, electrical facilities in compressor building and near gas headers			X	
	- Maintain necessary electrical circuits for emergency lighting and circuits needed to protect equipment from damage			X	
	ESD system must be operable from at least two locations, each of which is:				
	- Outside the gas area of the station			X	
	- Not more than 500 feet from the limits of the station			X	
	- ESD switches near emergency exits?			X	
.167 (b)	For stations supplying gas directly to distribution systems, is the ESD system configured so that the LDC will not be shut down if the ESD is activated?			X	
.167(c)	Are ESDs on platforms designed to actuate automatically by…				
	- For unattended compressor stations, when:				
	▪ The gas pressure equals MAOP plus 15%?			X	
	▪ An uncontrolled fire occurs on the platform?			X	
	- For compressor station in a building, when				
	▪ An uncontrolled fire occurs in the building?			X	
	▪ Gas in air reaches 50% or more of LEL in a building with a source of ignition (facility conforming to **NEC Class 1, Group D** is not a source of ignition)?			X	
.171(a)	Does the compressor station have adequate fire protection facilities? If fire pumps are used, they must not be affected by the ESD system.			X	
(b)	Do the compressor station prime movers (other than electrical movers) have over-speed shutdown?			X	
(c)	Do the compressor units alarm or shutdown in the event of inadequate cooling or lubrication of the unit(s)?			X	
(d)	Are the gas compressor units equipped to automatically stop fuel flow and vent the engine if the engine is stopped for any reason?			X	
(e)	Are the mufflers equipped with vents to vent any trapped gas?			X	
.173	Is each compressor station building adequately ventilated?			X	
.457	Is all buried piping cathodically protected?			X	
.481	Atmospheric corrosion of aboveground facilities			X	
.603	Does the operator have procedures for the start-up and shut-down of the station and/or compressor units?			X	
	Are facility maps current/up-to-date?			X	

COMPRESSOR STATIONS INSPECTION(NO COMPRESSOR STATIONS) (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c)		S	U	N/A	N/C
.616	Public Awareness Program effectiveness - Visit identified stakeholders as part of field inspection routine			X	
.615	Emergency Plan for the station on site?			X	
.707	Markers			X	
.731	Overpressure protection – reliefs or shutdowns			X	
.735	Are combustible materials in quantities exceeding normal daily usage, stored a safe distance from the compressor building?			X	
	Are aboveground oil or gasoline storage tanks protected in accordance with **NFPA standard No. 30?**			X	
.736	Gas detection – location			X	

Comments:
NO COMPRESSOR STATIONS

Alternative Maximum Allowable Operating Pressure

For additional guidance refer to http://primis.phmsa.dot.gov/maop/faqs.htm
For Additional guidance see the FAQs at http://primis.phmsa.dot.gov/maop/faqs.htm

192.620	Alternative MAOP Procedures and Verifications (No Alternative MAOP on Transmission Segments)	S	U	N/A	N/C

	The alternative MAOP is calculated by using different factors in the same formulas used for calculating MAOP in §192.619. In determining the alternative design pressure under §192.105 use a design factor determined in accordance with §192.111(b), (c), or (d), or, if none of these apply in accordance with: Class Location — Alternative Design Factor (F) 1 — 0.80 2 — 0.67 3 — 0.56					
.620(a)	(1) Establish alternative MAOP commensurate with class location – no class 4				X	
	(2) MAOP cannot exceed the lowest of the following:					
	(i) Design pressure of the weakest element				X	
	(ii) Test pressure divided by applicable factor				X	
.620(b)	(2) Pipeline constructed of steel pipe meeting additional requirements in §192.112.				X	
	(3) SCADA system with remote monitoring and control				X	
	(4) Additional construction requirements described in §192.328				X	
	(5) No mechanical couplings				X	
	(6) No failures indicative of systemic material fault – if previously operated at lower MAOP				X	
	(7) 95% of girth welds have NDT				X	
.620(c)	(1) PHMSA notified 180 days before operating at alternative MAOP				X	
	(2) Senior Executive signatures and copy to PHMSA				X	
	(4) Strength test per §192.505 or certify previous strength test				X	
	(6) Construction tasks treated as covered tasks for Operator Qualification				X	
	(7) Records maintained for life of system				X	
	(8) Class location change anomaly remediations				X	
.620(d)	(1) Threat matrix developed consistent with §192.917				X	
	(2) Recalculate the potential impact circle per §192.903 and implement public education per §192.616				X	
	(3) Responding to an emergency in an HCA					
	(i) Identify HCAs using larger impact circle				X	
	(ii) Check personnel response times				X	
	(iii) Verify remote valve abilities				X	
	(iv) Verify line break valve control system				X	
	(4) Protect the right-of-way:					
	(i) ROW patrols 12 per year not to exceed 45 days				X	
	(ii) Plan to identify and mitigate unstable soil				X	
	(iii) Replace loss of cover if needed				X	
	(iv) Use line-of-sight markers per §192.707				X	
	(v) Review damage prevention program in light of national consensus practices				X	
	(vi) ROW management plan to protect against excavation activities				X	
	(5) Control Internal Corrosion:					
	(i) Program to monitor gas constituents				X	
	(ii) Filter separators if needed				X	
	(iii) Gas Monitoring equipment used				X	
	(iv) Cleaning pigs, inhibitors, and sample accumulated liquids					
.620(d)	(v) Limit CO_2, H_2S, and water in the gas stream				X	
	(vi) Quarterly program review based on monitoring results				X	
	(6) (i) Control interference that can impact external corrosion				X	
	(ii) Survey to address interference currents and remedial actions				X	

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192.620	Alternative MAOP Procedures and Verifications (No Alternative MAOP on Transmission Segments)	S	U	N/A	N/C
	(7) Confirm external corrosion control through indirect assessment			X	
	(i) Assess adequacy of CIS and perform DCVG or ACVG within 6 months				
	(ii) Remediate damage with IR drop > 35%			X	
	(iii) Integrate internal inspection results with indirect assessment			X	
	(iv) Periodic assessments for HCAs			X	
	(A-C) Close interval surveys, test stations at ½ mile intervals, and integrate results				
	(8) Cathodic Protection			X	
	(i) Complete remediations within 6 months of failed reading				
	(ii) Confirm restoration by a close interval survey			X	
	(iii) Cathodic protection system operational within 12 months of construction completion			X	
	(9) Baseline assessment of integrity			X	
	(i)(A) Geometry tool run within 6 months of service				
	(i)(B) High resolution MFL tool run within 3 years of service			X	
	(ii) Geometry and MFL tool 2 years prior to raising pressure for existing lines			X	
	(iii) If short portions cannot accommodate tools, use direct assessment per §192.925, 927, 929 or pressure testing			X	
	(10) Periodic integrity assessments			X	
	(i) Frequency for assessments determined as if all segments covered by Subpart O				
	(ii) Inspect using MFL tool or direct assessment per §192.925, 927, 929 or pressure testing.			X	
	(11) Repairs			X	
	(i)(A) Use of the most conservative calculation for anomaly remaining strength				
	(B) Tool tolerances taken into consideration			X	
	(ii) Immediate repairs for:			X	
	(A) Dents meeting 309(b) criteria				
	(B) Defects meeting immediate criteria in §192.933(d)			X	
	(C) Calculated failure pressure ratio less than 1.25 for .67 design factor			X	
	(D) Calculated failure pressure ratio less than 1.4 for .56 design factor			X	
	(iii) Repairs within 1 year for:			X	
	(A) Defects meeting 1 year criteria in 933(d)				
	(B) Calculated failure pressure ratio less than 1.25 for .80 design factor			X	
	(C) Calculated failure pressure ratio less than 1.50 for .67 design factor			X	
	(D) Calculated failure pressure ratio less than 1.80 for .56 design factor			X	
	(iv) Evaluate defect growth rate for anomalies with > 1 year repair interval and set repair interval			X	
	(1) Provide overpressure protection to a max of 104% MAOP			X	
.620(e)					
	(2) Procedure for establishing and maintaining set points for SCADA			X	

Comments:

Comments: **No Alternative MAOP on Transmission Segments**

Recent Gas Pipeline Safety Advisory Bulletins: (Last 2 years)

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-09-02	Sept 30, 2009	Weldable Compression Coupling Installation
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-10-02	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-10-07	August 31, 2010	Liquefied Natural Gas Facilities: Obtaining Approval of Alternative Vapor-Gas Dispersion Models
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
ADB-11-02	February 9, 2011	Dangers of Abnormal Snow and Ice Build-up on Gas Distribution Systems

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

Comments: