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			
Docket Number	110017		
Inspector Name & Submit Date	Stephanie Zuehlke, 8/15/2011		
Chief Eng Name & Review Date	Joe Subsits 8/25/2011		
Operator Information			
Name of Operator:	Georgia Pacific Consumer Products, (Camas Mill) (LLC)	**OP ID #:**	31096
Name of Unit(s):	Same		
Records Location:	On-site & consultant R. R.'s home – West Linn, OR		
Date(s) of Last (unit) Inspection:	September 15, 16, 17, 29, 30 & October 1, 2008	**Inspection Date(s):**	July 11-13, 18-20, 2011

Inspection Summary:

1. Roy Rogers, Camas compliance consultant usually fills out std. form with all O&M sections – since std inspection and not O&M if provided they will be included in form but not reviewed.
2. Non jurisdictional metering station that verifies Williams meters and cuts pressure to 50 psig inside plant fence. 250 psig from Williams, GP gives plant 240 psig to plant and cuts to 50 psig inside plant. Regulators that cut to 50 are Non jurisdictional.
3. 30 C Street, Camas is William's gate station address.
4. Pipeline is piggable.
5. GP does not odorize gas -NWN odorizes all gas from Battle ground to Medford.
6. Williams's line by transfer flange has inoperative remote shut off valves that used to be controlled by Salt Lake. Williams is no longer able to shut valve - GP personnel must respond to turn wheel valves manually – w/approx. 3-5 min. est. response time.
7. Flow meter installed in 2007 replaced old turbine meter for purpose of verifying Williams meter/useage read.
8. Plant does have telemetry – high and low alarms only, see later details regarding alarm set points. MAOP 250psig.
9. Williams has dual monitor runs for Camas w/relief=Anderson Greenwood. Williams used ultrasonic. The line is filtered. Williams cuts from 800 psig thru heater to </=250psig at gate.
10. MERT (Mill Emergency Response Team) responds to gas emergency however, there are others (see OQ records) able to respond. Camas policy is to shut down in emergency. Maintenance would only shut off system for repairs if necessary. They would use Plidco bolt on clamps – see details of Plidco – no procedures for this application/construction method/repair.
11. This pipeline saw construction for the 1st time in 2010 – multiple issues/problems with procedures, D/A, OQ, testing, etc. See below for details.
12. Documents from OQ AOC's in file. Requested docs with dates.

Staff is generally concerned with lack of updated procedures, welder testing records, detail, and records documenting completion of inspections/surveys, etc. tasks

HQ Address:	**System/Unit Name & Address:**
133 Peach Tree Street NE Atlanta, Georgia 30303	401 NE Adams Street Camas, WA 98607
Co. Official: Gary W. Kaiser, VP **Phone No.:** **Fax No.:** **Emergency Phone No.:** 360.834.8106 Gary.kaiser@gapac.com	**Phone No.:** 360.834.3021 Ext. 3213- Attendant GRP_CAM.Clockroom@gapac.com **Fax No.:** 360.834.8462 – Dispatch Verifying **Emergency Phone No.:**

Persons Interviewed	Title	Phone No.
Lorie Lehman	HR Mgr. – Halsey Mill OR	541.369.1208
Jim Gosnell	Operations Manager	360.834.8107
Ronald K. Kramer	HR Manager – Camas (New employee)	360.834.8101
Steve Ringquist	Reliability Leader Steve- ringquist@gapac.com	360.834.8166
Roy Rogers	Consultant Cathodic Protection Engineering, Inc.	503.720.3220
Patrick J. Terry	Welding/Sr. Staff Project Engineer	360.834.8135
Barry Carson	Tech. Ldr. & Acting Mill Mgr.	360.834.8413

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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. (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:**	April 6-8, 2009

GAS SYSTEM OPERATIONS			
Gas Supplier	Williams Northwest Pipeline		
Number of reportable safety related conditions last year 2008: reported None 2011: 0		Number of deferred leaks in system 2008: reported none 2011: None	
Number of non-reportable safety related conditions last year 2008: reported none 2011:None		Number of third party hits last year 2008: reported none 2011: None	
Miles of transmission pipeline within unit (total miles and miles in class 3 & 4 areas) 2011: 1.68 miles total Class 3			
Operating Pressure(s):		**MAOP (Within last year)**	**Actual Operating Pressure** (At time of Inspection)
Feeder:	800psig (Williams)	250psig	240psig (07.10-11.11 – reviewed chart)
Town:	50psig in plant Non-jurisdicational (ASME)	N/A	N/A
Other:	None	N/A	N/A
Does the operator have any transmission pipelines?	Yes		
Compressor stations? Use Attachment 4.	No compressor stations this location		

Pipe Specifications:			
Year Installed (Range)	1993 and 2010	Pipe Diameters (Range)	10"
Material Type	steel	Line Pipe Specification Used	API 5L (X-42/X-52 with varying wall thickness – approx.. 4 thicknesses)
Mileage	1.68 miles	SMYS %	10.4%
Supply Company	CSI – California Steel	Class Locations	3

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:** 07.20.2011

PART 199 DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES		S	U	NA	NC
Subparts A – C PV	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.		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). 192.631 (a) General. (1) 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. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of: (i) Distribution with less than 250,000 services, or (ii) Transmission without a compressor station, the operator must have and follow written			x	

	procedures that implement only paragraphs **(d)** (regarding fatigue), **(i)** (regarding compliance validation), and **(j)** (regarding compliance and deviations) of this section. **(d)** Fatigue mitigation. Each 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 roles and responsibilities the operator has defined: (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. **(i)** Compliance validation. Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency. **(j)** Compliance and deviations. An operator must maintain for review during inspection: (1) Records that demonstrate compliance with the requirements of this section; and (2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.				

		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. Reported January 2010 and next report May 2011 which exceeds the 12 month requirement. No changes in pipeline **GP (Contractor Roy Rogers- reported that NPMS tolerance is 50' due to mapping resolution** – Since MAOP not over 250 psig not required to submit to NPMS. Removing 3.8.18 from O & M and redrafting language to identify voluntary submission for map changes. This has been completed.	x			
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?	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).	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).	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). (This is a leak and test failure report)	x			
6.	191.15(c)	Supplemental report (to 30-day follow-up)	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).	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). Ask operator questions under this section about Construction/replacement etc. > $10Million Etc....	x			
9.	191.23	Safety related condition reports Okay – 2.6.2 O&M dated 06.30.11	x			
10.	191.25	Filing the SRCR within 5 days of determination, but not later than 10 days after discovery2.6.2 O&M dated 06.30.11	x			

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		REPORTING RECORDS	S	U	N/A	N/C
11.	192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports	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;	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	x			

Comments:

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			

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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:

			S	U	N/A	N/C
40.	480-93-200(7)	**Annual Reports** filed with the commission no later than **March 15** for the proceeding calendar year				
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	x			
42.	480-93-200(7)(b)	Damage Prevention Statistics Report including the following; 2009 and 2010 okay	x			
43.	480-93-200(7)(b)(i)	Number of gas-related one-call locate requests completed in the field; 2009-4& 2010-4 okay	x			
44.	480-93-200(7)(b)(ii)	Number of third-party damages incurred; and okay – 0 2009-10 reviewed in office	x			
45.	480-93-200(7)(b)(iii)	Cause of damage, where cause of damage is classified as one of the following: (A) Inaccurate locate; (B) Failure to use reasonable care; (C) Excavated prior to a locate being conducted; or (D) Other Okay – reviewed in office for 2009-10	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. Okay – reviewed in office for 2009-10	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 Received on March 16, 2011	x			

Comments:

CONSTRUCTION RECORDS			S	U	N/A	N/C
50.	192.225	Test Results to Qualify Welding Procedures **Reviewed in October 2008 - O&M Section 4.7.1** **Section 4.7.1 for V groove, fillet, . Reviewed specification, reviewed the procedure qualification and the Braun Co testing information** Any new welding procedures qualified since October 2008? None. Reviewed procedures Section IX, ASME Boiler and Pressure Vessel Code. All dated 1996. 192.229 Appendix C ASME section IX	x			

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CONSTRUCTION RECORDS			S	U	N/A	N/C
51.	192.227 PV for no OQ to qaul.welding proc., Plan & Procedures PV for API 1104 version, and Records PV	Welder Qualification 1. O&M Section 4.7.3 Welder Qualifications dated 06.30.11 states API 1104 19th Edition -PV 2. O&M Section 4.8 NDT states API 1104 19th Edition need to update procedures to 20th Edition per 192.7 Effective date of 20th Edition is October 1, 2010, which eliminates use of prior versions. 3. NDT Section 4.0 Reference Codes API 1104 19th Edition is referenced. Effective date of 20th Edition is October 1, 2010, which eliminates use of prior versions. 4. Requested OQ & NDT certification for inspecdors - These documents were not kept as part of the construction records for the life of the pipe as is required by WAC -018 • Contractor procedures – copies of pages 1, 3, 8, 11, & 14 showing below contractor requirements that BP did not have in their construction documents. • Nicholas J. Rossiello Radiographer/mag particle/penetrant Level II: o ***No records in construction documents showing no lapse of service exceeding 9 months of first read completed on 04.13.10.***-Reviewed NWN work dated 01.04.10 o Eye exam completed 05.15.09-okay • Robert Madden Level II Radiographer/Mag particle/penetrant: o ***No records for this individual included in construction documents*** o ***No records in construction documents showing certified*** o ***No records in construction documents showing no lapse of service exceeding 9 months of first read completed on 04.20.10*** Reviewed NWN constr. Report dated 07.23.09. o ***No records in construction documents showing eye exam*** Eye exam docs showing expiration of 12 month exp. Eye test dated 12.03.10. 5. PV - Requested OQ accepatance review documentation of contractor SR 14 relocation job. Requirements of contractor in O&M manual – Section 4 of Appendix. – Per 192.807 – Roy did not feel this should be part of the project since he signed a paper saying he had reviewed and they were okay – I identified that the OQ section mentioned above states they must at least be maintained for 5 years. • Patrick Helleck qualified on 04.09.10 just prior to work. To weld procedure No. GP CAMAS-01 X-52 pipe when he completed an X-42 test – this is a change in essential variables – check whether he tested X-42/X-52 pipe THE WELDER QUAL. TEST DOES NOT STATE WHAT QUALIFIED PROCEDURE HE TESTED TO. • Requested construction permission docs submitted to UTC and test docs to determine pipe wall thickness. Several docs show variable wall thicknesses – tested to minimum thickness of 0.307 wall. 4 WALL THICKNESSES • Requested test docs for entire line. 6. Requested subcontractor Rick Dean Construction inspector. Roy Rogers directly supervised. Identified to Roy that documentation establishing an PM/inspector certifications should showvalidation of inspector knowledge and qualifications. 7. Requested welding qual. records for 2009/2010 for GP welders Randy Howe and Ron Higdon		x		
52.	192.241(a)	Visual Weld Inspector Training/Experience Testing 192.241(a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that: (1) The welding is performed in accordance with the welding procedure; and (2) The weld is acceptable under paragraph (c) of this section. Not in procedures to meet language. Section 4.8 page 6.	x			
53.	192.243(b)(2)	Nondestructive Technician Qualification See #51 above	x			
54.	192.243(c)	NDT procedures See #51 above	x			
55.	192.243(f)	Total Number of Girth Welds (f) When nondestructive testing is required under §192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects. Number 23 NDT Girth Welds; 24 NDTs, 0 rejected. Roy corrected a typo on radiographic weld mapping. 40' section 10"	x			
56.	192.243(f)	Number of Welds Inspected by NDT See #55	x			
57.	192.243(f)	Number of Welds Rejected See#55	x			
58.	192.243(f)	Disposition of each Weld Rejected See #55	x			

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CONSTRUCTION RECORDS			S	U	N/A	N/C
59.	480-93-080(1)(b) PV put under 192	Use of testing equipment to record and document essential variables Reviewed duration is 8 hrs. per GP jprocedures. Hydro tested. Reviewed design factors of this pipe and is in file. Requested procedures on whether they have hydro/test acceptance procedures.		x		
60.	480-93-115(2)	Test leads on casings (without vents) installed after 9/05/1992 Abandoned on Uunion in 2010. 2008 reads -1.35 carrier and casing -.0.42 January March 2, 2008 okay, May 2008. September. November Reviewed 2010 for casing.	x			
61.	480-93-115(3)	Sealing ends of casings or conduits on Transmission lines and main okay reviewed docs/photos of abandonment.	x			
62.	480-93-115(4)	Sealing ends (nearest building wall) of casings or conduits on services N?A	x			
63.	192.303 PV 480.93.180 Plans and procedures violation.	Construction Specifications X-42 pipe with 0.365 wall per DOT 192.149 Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability. (a) Each imperfection or damage that impairs the serviceability of a length of pipeline of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must a least be equal to either: (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or (2) the design pressure of the pipeline. Jeeping procedures: There is no procedure and ask for minimum thickness tolerances in the pipe spec. 12-14 mils. Since identifying this missing procedure, Roy has written new procedure.		x		
64.	192.325	Underground Clearance Procedure 3.7 page 23 identifies clearance.	x			
65.	192.327 PV in plans & Prcedures.	Amount, Location, Cover of each Size of Pipe Installed Cover requirements met in project repairing coating (in beginning summary) with cover of 42" on 10" pipe. 36" requirement per 192.327(a). Plans and procedures do not contain minimum cover requirements. Construction documents from Section 15480 identify 36" and the 2010 construction documents identify cover as 8' but there is no procedure in their O&M Manual for cover.		x		
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: • Quality assurance • Girth welds • Depth of cover • Initial strength testing, and; • Interference currents?	x			
67.	480-93-160(1) PV	Detailed report filed 45 days prior to construction or replacement of transmission pipelines ≥ 100 feet in length 1. GP did not submit construction documents to UTC 45 days prior to construction due to changes forced by DOT. GP states that Dave Lykken or Joe Subsits approved construction. 2. Requested annual report 3 times but did not receive.		x		
68.	480-93-170(3)	Pressure Tests Performed on new and replacement pipelinesSr – 14 project – reviewed tests completed 8 hr. reviewed procedure docs which state 8 hr test.	x			
69.	480-93-170(10) PV for P&Proc.	Pressure Testing Equipment checked for Accuracy/Intervals (Manufacturers Recom or Operators schedule) Requested procedure which states required calibration intervals: Reviewed ITT Barton 12" 3Kpsi 0-150F SN U242-083095-1 dated 04.06.10 Reviewed ITT Barton 12" 3Kpsi 0-150F SN U242-083095-2 dated 04.06.10 Requested documentation identifying of equipment that are designated as calibrated but not what equipment is – they identified it as a gauge used during testing incrementations. GP should identify which equipment is used. No procedure identifying operators calibration frequency – they mimic (10) of the rule here. Their procedure dated June 30, 2011 Page 7 of 4.8(8) is incorrect.		x		

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CONSTRUCTION RECORDS			S	U	N/A	N/C
70.	480-93-175(1)	Study prepared and approved prior to moving and lowering of metallic pipelines > 60 psig O&M 4.15 okay.	x			
71.	192.455	Cathodic Protection Coating CP 3.3.2 1. requested 1993 origination documents for CP on line within 1 yr.- September 5, 1993: Okay. 2. requested 2010 documents for CP on line within 1 yr. – protected 02.27.10 and 05.10.10 after install occurred in year as pipe install	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 identified no unsafe conditions/issues	x			
74.	192.14 (a)(3)	Correction of unsafe defects and conditions 3.1 identifies unsafe conditions to address	x			
75.	192.14 (a)(4)	Pipeline testing in accordance with Subpart J Original Hydro test performed August 30, 1993. 04.14.10 hydro test okay.	x			
76.	192.14 (b)	Pipeline records: investigations, tests, repairs, replacements, alterations (life of pipeline) Identified under other locations in this form.	x			
77.	192.16	Customer Notification (**Verification – 90 days – and Elements**) none	x			
78.	192.603(b) PV	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 Exceeded NTE 15 mos. 2009 review occurred 03.2009 and 12.2010 a total of 18-19 mos. Per 192.605(a) This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least one each calendar year.		x		
79.	192.603(b)	Abnormal Operations .605(c) (c) Abnormal operation. For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded: (1) Responding to, investigating, and correcting the cause of: (i) Unintended closure of valves or shutdowns; (ii) Increase or decrease in pressure or flow rate outside normal operating limits; (iii) Loss of communications; (iv) Operation of any safety device; and, (v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property. (2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation. (3) Notifying responsible operator personnel when notice of an abnormal operation is received. (4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found. (5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connections with their distribution system.	x			
80.	192.603(b)	Availability of construction records, maps, operating history to operating personnel .605(b)(3) included in manual	x			

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		OPERATIONS and MAINTENANCE RECORDS	S	U	N/A	N/C
81.	192.603(b)	Periodic review of personnel work – effectiveness of normal O&M procedures .605(b)(8) Todd Kuhnhausen OQ: excavation standby 06.21.11 reviewed by Roy Rogers Kevin Goodell OQ: excavation stand-by 06.21.11reviewed by Roy Rogers	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) PV	List of Current Excavators .614 (c)(1) (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. GP O&M Manual 3.7 Damage Prevention does not identify a current list of excavators		x		
85.	192.603(b) PV	Notification of Public/Excavators .614 (c)(2) (2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program: (i) The program's existence and purpose; and (ii) How to learn the location of underground pipelines before excavation activities are begun. Public notice of GP is provided to equip rental companies – 2 locally and placed on counters. Personally provided to all on list. • Northwest Natural is missing from the list of excavators NWN is the natural gas provider in Camas. Reviewed documents for 2006-2011 and was not provided with info. • Williams Pipeline is missing from the list of excavators and was not provided with info • GP O&M Manual 3.7 Damage Prevention does not identify a current list of public		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? (6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities: (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and (ii) In the case of blasting, any inspection must include leakage surveys.	x			
89.		2. In the case of blasting, does the inspection include leakage surveys? (required)	x			
90.		**Damage Prevention (Operator Internal Performance Measures)**				
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 N x					
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) No formal program but contract with Roy identifies required correct completion of all locates for GP. Oversight provided by Steve Ringquist.	x			
93.		Does operator including performance measures in facility locating services contracts with corresponding and meaningful incentives and penalties? unknown	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? In-house locating	x			
95.		Does the operator periodically review the Operator Qualification plan criteria and methods used to qualify personnel to perform locates? OQ-005 qualification methods	x			
96.		Review operator locating and excavation procedures for compliance with state law and regulations.	x			

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OPERATIONS and MAINTENANCE RECORDS			S	U	N/A	N/C
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) PV	Liaison Program with Public Officials .615(c) (c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to: (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency; (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency; (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and, (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property. Camas has an E-plan but does not identify those public officials that it liaisions with and the frequency with which they complete it. No records available and the procedures do not identify. Include listing of officials in your Eplan. 5. Question: Suppose the date for the meeting is set and invitations are sent to the public officials but only a few attend. Does this constitute as an acceptable face-to-face liaison meeting? Answer: The operator would have had a face-to-face establishment and continuing liaison only with those public officials that attended the meeting. For those public officials that are continually invited but will not attend a meeting, OPS will accept documented efforts to comply with this requirement by having the operator keep the following items as part of their records: roster of invited entities, meeting minutes, an attendance list and return receipts indicating the minutes were sent to those not attending. An operator may choose to document its efforts through alternate means; however, efforts to establish and maintain a liaison with public officials must be positively documented. Frequency of Face-to-Face Meetings 6. Question: How often are the meetings required? Answer: OPS recommends that meetings be held as often as necessary for the public officials and pipeline personnel to stay current on emergency response information and revisions to those procedures. When determining the frequency of these meetings, the operator should consider revisions to names and phone numbers, personnel changes of public officials, and the need for public officials to receive refresher training regarding procedures they do not use on a routine basis. Sincerely,		x		

Comments:

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			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**				
107.	192.603(b)	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.		Documentation properly and adequately reflects implementation of operator's Public		x		

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 Completed Annually Items identified in PA (Public Notice) Notification dated 03.16.09 do not match the baseline message requirements. Message items missing.
Emergency Officials	Annual Completed Annually Items identified in PA (Public Notice) Notification dated 03.16.09 do not match the baseline message requirements. Message items missing.
Public Officials	3 years Completed Annually Items identified in PA (Public Notice) Notification dated 03.16.09 do not match the baseline message requirements. Message items missing.
Excavator and Contractors	Annual Completed Annually Northwest Natural is missing from the list of excavators NWN is the natural gas provider in Camas. Reviewed documents for 2006-2011. Williams Pipeline is missing from the list of excavators.
One-Call Centers	As required of One-Call Center Appears okayl.

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

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109.		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) (e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. (f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. Documentation provided to stakeholders does not meet P/A plan requirements for all 4 groups.				
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) Evaluation of effectiveness does not have a date other than 2010 that identifies completion of effectiveness. The Effectiveness program does not address or illicit a response from stakeholders and does not identify who responded or how responded. I asked Roy/GP to identify how they arrived at their conclusions.		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) None	x			

Comments:

113.	192.517	Pressure Testing – Requested %SMYS testing. Design records only indicate the 250psi MAOP. Pressure test docs not available in construction records – asked for %SMYS of hydro.	x			
114.	.553(b)	Uprating	x			
115.	192.709	%				
116.	.709	**Note: If the operator is operating at 80% SMYS with waivers, the inspector needs to review the special conditions of the waiver**. SMYS 10.42%				
117.		MAOP cannot exceed the lowest of the following: .619				
118.		Design pressure of the weakest element, .619(a)(1) Amdt, 192-103 pub. 06/09/06, eff. 07/10/06 Weakest element is 0.307 X-42 pipe - 3695ft.	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)
1993 10.75" various walls highest actual operating pressure 241psig
<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.</td><td>x</td><td></td><td></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 None</td><td>x</td><td></td><td></td><td></td></tr>
<tr><td>122.</td><td>480-93-015(1)</td><td>Odorization of Gas – Concentrations adequate No annual maintenance records of NWN odorizer</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 Reviewed January through December</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 None</td><td>x</td><td></td><td></td><td></td></tr>
<tr><td>125.</td><td>480-93-015(4)
PV</td><td>Odorant Testing Equipment Calibration/Intervals (Annually or Manufacturers Recommendation)
Procedures do not include language identifying re-cal requirements. Page 3 of GP O&M Manual 3.1.2 Odorant testing – copy in folder. Staff notes there are re-cal requirements for the Odorator in Appendix B under Calibration and Periodic test records stating 30 day periodic tests and annual re-cal requirements.
Although no annual maintenance occurred in 2009 the operator did not utilize the equipment outside of the calibration period. Reviewed 12.16.08, 01.08.10, and 02.18.11 re-cal certs by Heath.</td><td></td><td>x</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) okay</td><td>x</td><td></td><td></td><td></td></tr>
<tr><td>127.</td><td>480-93-124(4)
PV</td><td>Markers reported missing or damaged replaced within 45 days?
Procedures do not reflect the reporting and replacement of markers within the 45 day timeframe.
O&M manual identifies that line marker surveys will be retained for a minimum of 5 years. It identifies that a line marker inspection form exists in Section 3 of the Appendix. (copy in file) I reviewed the latest inspection completed on 07.06.08 Titled Annual Line Marker Inspection Form. Identified that the marker patrol frequency be included in the procedures. Roy identified that he completes the patrol monthly but will adjust manual to include the words ""annually" and will also make all patrol information concerning markers on the preveisly mentioned marker form.</td><td></td><td>x</td><td></td><td></td></tr>
</table>

Comments:

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128.	480-93-185(1)	Reported gas leaks investigated promptly/graded/record retained None. Requested procedure	x			
129.	480-93-185(3) AOC	Leaks originating from a foreign source reported promptly/notification by mail/record retained O&M Procedure 3.2.3 (copy in file) correct procedure to state property owner or adult occupant.		x		
130.	480-93-187	Gas Leak records None	x			
131.	480-93-188(1) PV	Gas Leak surveys Suggested that Roy better identify system description possibly with stationing and highlighting of map that reflects. 10.26.08, 09.19.09, 10.02.10 • No maps available for the above three surveys. Roy identified that he used the same map always since nothing has ever changed. I identified that in 04. 2010 they relocated/offset main for 320 ft and that is not reflected on the map he provided dated 2009 that he is still using. No 2010 map and no map provided with 2008 survey. Map for 2009 only in folder • 480-93-018(5) Maps have not been updated within 6 months of construction.04.26.10 • Records identify that the annual pipeline leak survey was completed on 10.16.10 but the correspondence to GP regarding survey is dated 10.02.10 which is prior to the calibration of FI (Detecto-Pak 4 SN 1500909001). 2010 annual survey and calibration records in folder. • In 2008, 2009, and 2010, gas (marsh gas was detected) was detected by the FI unit. Leak survey procedure OQ-008 identifies that once gas is detected they must comply with leak investigation procedure. (Forms in folder) o No leak investigation completed per OQ-008 & OQ-009 or Emergency Plan 2.1 – leak was not graded. (copies of all three procedure OQ in folder. ▪ Leak investigation Form not completed for identified leaks (swamp gas) in 2008, 2009, 2010) Copy of form in folder o A CGI was used but not documented – no SN identified ▪ No Calibration records provided for CGI ▪ No leak report completed ▪ No leak grade was identified.	x			
132.	480-93-188(2) PV Dave?	Gas detection instruments tested for accuracy/intervals (Mfct rec or monthly not to exceed 45 days) CGI calibration records requested for 2008, 2009, & 2010. Did not utilize on found leaks – determined to be marsh gas.		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	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	x			
136.	480-93-188(4)(c)	Special leak surveys - Unstable soil areas where active gas lines could be affected	x			
137.	480-93-188(4)(d)	Special leak surveys - areas and at times of unusual activity, such as earthquake, floods, and explosions	x			
138.	480-93-188(5) PV	Gas Survey Records See #131 no maps no investigation forms.		x		

139.	480-93-188(6) PV	Leak Survey Program/Self Audits Records are inaccurate and incomplete – people are not following procedures and required records have not been completed.		x		
140.	192.709 AOC Same as #157.	Patrolling (**Refer to Table Below**) .705 completed on a monthly basis Completed monthly. Reviewed 2010. OQ-006 for patrolling identifies several items to be reviewed during patrolling but they are not all including in the summary. I suggested that they may want to identify and check off all items to ensure none are left off so as to verify they were indeed reviewed during patrol. Copy in folder of OQ-006 and January & February 2010 patrol records.		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 Completed annually due to odorized T-gas	**4/yr**	**4½ months**

142.	192.605(b)	Abandoned Pipelines; Underwater Facility Reports .727(g)	x			
143.	192.709	Compressor Station Relief Devices (**1 per yr/15 months**) .731(a) None	x			
144.	192.709	Compressor Station Emergency Shutdown (**1 per yr/15 months**) .731(c) None	x			
145.	192.709	Compressor Stations – Detection and Alarms (**Performance Test**) .736(c) None	x			
146.	192.709	Pressure Limiting and Regulating Stations (**1 per yr/15 months**) .739 Reviewed 2008, 2009, 2010	x			
147.	192.709	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**) .743	x			

Comments:

148.	192.709 PV for valve records. PV for not following procedures 3.1.5 Valve inspection.	Valve Maintenance (**1 per yr/15 months**) .745 completed quarterly – reviewed 2008, 2009 WAC 480-93-018(4) Each gas pipeline company must record and maintain records of the actual value of any required reads, tests, surveys or inspections performed. The records must include the name of the person who performed the work and the date the work was performed. The records must also contain information sufficient to determine the location and facilities involved. Examples of the values to be recorded include, but are not limited to, pipe to soil potential reads, rectifier reads, pressure test levels, and combustible gas indicator reads. A gas pipeline company may not record a range of values unless the measuring device being used provides only a range of values. Records issues: Reviewed 2008, 09, 10, and 2011(3 inspections) – but a records issue. GP does not maintain the original records of valve inspections for 2008, 2009, 2010, 2011. Copies in folder.		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			

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151.	192.603(b) PV	Welding – Procedure .225(b) See #51through #53		x		
152.	192.603(b) PV	Welding – Welder Qualification .227/.229 See #51through #53		x		
153.	192.603(b) PV	NDT – NDT Personnel Qualification .243(b)(2) See #51through #53		x		
154.	192.709	NDT Records (**Pipeline Life**) .243(f) See #51through #53	x			
155.	192.709	Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**)	x			

156.	.807(b)
	PV
		Refer to PHMSA Form # 15 to document review of operator's employee covered task records
		<u>192.805 Each operator shall have and follow a written qualification program.</u>
		GP's OQ Program identifies that a specific employee (Reliability Mgr. or Utility Operations Mgr.) will approve contractors submitted credentials and sent a written confirmation to contractor advising that Camas has accepted the Contractor OQ program and will also specifically identify which covered tasks the Contractor is authorized to perform.
		I reviewed the 2008 (which was in effect at the time of the 2010 construction project) and 2011 versions – both say this is required but not done. <u>Did not follow OQ procedures per above.</u>
		<u>No OQ records available for contractor personnel working on 2010 construction project.</u>
		• NDT people – Nicholas Roselliano and Robert Madden
		• Alaska Continental Pipeline
		    o George Culp
		    o Patrick Helleck
		    o Micahel Iverson
		    o Gary Johnson
		    o Zachary Justice
		    o David Lemmon
		    o Ernest Pauline
		    o Chris Plumer
		    o Mark Skodje
		    o Leroy Tavares
		    o Michael Waterfield
		    o Michael Whaley
		<u>Copy of Contractor list for 2010 construction project in folder.</u>
		OQ-001 – AOC's of all OQ procedures are contained in OQ-001 per GP. I do not find that all AOC's are identified here for example, bolt torqueing for Plidco fittings and flanges is not included. OQ procedures do not include AOC's and GP identified that when employees do a task they do not take the AOC OQ procedure with them. OQ procedure OQ-001 in folder.
				x		

157.	192.905(c) PV	Periodically examining their transmission line routes for the appearance of newly identified area's (HCA's) Patrolling records reviewed for 2010. Reviewed OQ-006 Transmission Pipeline Patrolling which identifies approx. 13 items to check during patrol one being HCA's. Suggested that GP use a list that incorporates all items identified in above OQ patrol procedure so as to identify none forgotten during patrol. Reviewed Summary record for 2010. Copies in folder: January 2010 and February 2010 and OQ-006.		x		

Comments:

		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			

		CORROSION CONTROL RECORDS	S	U	N/A	N/C
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) Completed bi-monthly – okay.	x			
168.	192.491	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) .465(e) None	x			
169.	192.491	Electrical Isolation (**Including Casings**) .467	x			
170.	480-93-110(2) AOC	Remedial action taken within 90 days (Up to 30 additional days if other circumstances. Must document) .465(d) 480-93-110(2) Each gas pipeline company must complete remedial action within ninety days to correct any cathodic protection deficiencies known and indicated by any test, survey, or inspection. An additional thirty days may be allowed for remedial action if due to circumstances beyond the gas pipeline company's control the company cannot complete remedial action within ninety days. Each gas pipeline company must be able to provide documentation to the commission indicating that remedial action was started in a timely manner and that all efforts were made to complete remedial action within ninety days. (Examples of circumstances allowing each gas pipeline company to exceed the ninety-day time frame include right of way permitting issues, availability of repair materials, or unusually long investigation or repair requirements.) 3.3.9 Procedures identify that they will make arrangements to correct the problem within 90 days. They will be correcting procedure to state remedial action will be completed within 90 days.		x		
171.	480-93-110(3) PV on ½ cell no accuracy/recal procedure	CP Test Equipment and Instruments checked for Accuracy/Intervals (Mfct Rec or Opr Sched) Requested multimeter recal documentation for 2009, 2010, & 2011. No recalibration certificate. For Fluke multimeter # 88340147 for 2009. Procedures do not identify that they throw out their half-cells on an annual basis		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 Does not apply	x			
175.	480-93-110(5)(c)	Casing shorts cleared when practical None	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 .473None	x			
178.	192.491	Internal Corrosion; Corrosive Gas Investigation .475(a) None and verified by review of interior of offset locations (2), also at pig launch capture locations, and in downstream location of reg sta 1956 vintage – okay. Reviewed all in April 2010.	x			
179.	192.491	Internal Corrosion; Internal Surface Inspection; Pipe Replacement .475(b) See above. None. Okay.	x			
180.	192.491	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems .476(d) None	x			
181.	192.491	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**) .477 None	x			
182.	192.491	Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**) .481 Completed on bi-monthly basis	x			
183.	192.491	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions .483/.485 – remediation for all to be completed within 90 days.	x			

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Comments:
480-93.180 Plans and Procedures. GP does not have a procedure for above ground coating/painting and no procedures for application and equipment use such as sandblasting, measurement of wall loss. No procedure for measurement of wall loss or use of equipment to complete measurement of wall loss. No OQ procedures for any of these.

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:** 08.27.2011

Comments:
No Compressor Stations this Operator

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COMPRESSOR STATIONS INSPECTION (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) **No Compressor Stations this Operator**		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	

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COMPRESSOR STATIONS INSPECTION (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) **No Compressor Stations this Operator**		S	U	N/A	N/C
	Are facility maps current/up-to-date?			x	
.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 this Operator

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 **Not Applicable**	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				
	(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	

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192.620		Alternative MAOP Procedures and Verifications **Not Applicable**	S	U	N/A	N/C
.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	
	(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	

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192.620	Alternative MAOP Procedures and Verifications **Not Applicable**	S	U	N/A	N/C
	(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				
.620(e)				x	
	(2) Procedure for establishing and maintaining set points for SCADA				

Comments:

Not Applicable

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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: