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	Ref #2611		
Inspector Name & Submit Date	Patti Johnson 11-6-2012		
Chief Eng Name & Review Date	Joe Subsits, 11/7/2012		
Operator Information			
Name of Operator:	Avista Corporation	**OP ID #:**	31232
Name of Unit(s):	Transmission line - Colville and Spokane Districts		
Records Location:	Spokane		
Date(s) of Last (unit) Inspection:	NA	**Inspection Date(s):**	10-22 thru 10-25-2012

Inspection Summary:

The Kettle Falls High Pressure gas line runs north from Spokane Washington to Kettle Falls Washington. The main is approximately 77 miles long and was originally constructed in 1966. It is constructed from 6" and 8" pipe and has an MAOP of 500 psig. Several regulator stations situated close to the main feed near-by communities, including Deer Park, Valley, Chewelah, Colville, and Kettle Falls. In 1983 the main was extended (with 8" pipe) approximately one mile to serve the then-new Kettle Falls Generating Station. In 2009 a new gate station was constructed in North Spokane that feeds the line through four miles of new non-transmission 12" main (19.9% SYMS). Over its 46 year life, the line has operated at pressures typically between 250 and 500 psig. In 1997 a thorough records study and leak survey was performed before raising the operating pressure back up to 485 psig. There are no High Consequence Areas next to the line.

Note: the four miles on new non transmission 12 main was installed because of building encroachment, it eliminated a possible HCA. The transmission line starts near the distribution regulator station on Rutter Park Way and Indian Trail.

HQ Address: PO Box 3727, Spokane, WA 99220	**System/Unit Name & Address:**
Co. Official: Don Kopczynski, Vice President, Energy Delivery **Phone No.:** **Fax No.:** **Emergency Phone No.:**	**Phone No.:** **Fax No.:** **Emergency Phone No.:**

Persons Interviewed	Title	Phone No.
Ken Sampson	Gas Local Rep	(509) 489- 500
Randy Bareither	Gas Engineer	(509) 489- 500
Sonia Johnson	Sr Compliance Tech	(509) 489- 500
Bob Larson	CP tech	(509) 489- 500
Brandon Beierle	Tech	(509) 489- 500
Shawn Gallagher	Leak Survey Atm Corr Manager	(509) 489- 500
Richard Inouye	Pressure Control man	(509) 489- 500
Randy Chandler	Spokane Operations Manager	(509) 489- 500
Kermit Olson	Colville Operations Manager	(509) 489- 500

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

Gary Douglas	Sr CP Tech	(509) 489- 500
Tim Harding	Gas Design Engineer	(509) 489- 500
Jeff Webb	Gas Design Manager	(509) 489- 500
Steve Winters	CP Tech	

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:**	4-2012

GAS SYSTEM OPERATIONS - TRANSMISSION			
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) **Total Transmission 72.67**		**58.1 miles in class 1, 12.56 miles in class 2, 1.9 miles in class 3**	
Operating Pressure(s):		**MAOP (Within last year)**	**Actual Operating Pressure** (At time of Inspection)
Feeder:		500	485
Town:			
Other:			
Does the operator have any transmission pipelines?	**yes**		
Compressor stations? Use Attachment 4.	**no**		

Pipe Specifications:			
Year Installed (Range)	**1966 to present**	Pipe Diameters (Range)	**6 and 8"**
Material Type	**steel**	Line Pipe Specification Used	**API 5L**
Mileage	**72.67**	SMYS %	**27.3% SYMS**
Supply Company	**Williams**	Class Locations	**1, 2 and 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: Full PHMSA DIMP inspection conducted in 2012**

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. **Mini Drug and Alcohol Headquarters inspection conducted in Pullman/Clarkston 2012 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). (a) General.	x			

	INFORMED AVISTA THERE WILL BE A FORMAL CONTROL ROOM INSPECTION IN 2013 (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: (ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section. – **Required information found in Avista's Control Room Management Plan Sections 400, 500, 800 And 900.** (2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by § § 192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than Febraury 1, 2013. – **Avista's Plan was developed 2010 and 2011 prior to July, implemented July 29, 2011.**				

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. Reviewed emails documenting submission	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). **Reviewed Avista's Gas Loss Calculator Spread sheet called "Rule of Thumb Gas Loss Calculator"**	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). **Most recent electronic submission was in 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). **None for transmission**	x			
6.	191.15(c)	Supplemental report (to 30-day follow-up) **Yes if needed**	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). **Yes**	x			

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

REPORTING RECORDS			S	U	N/A	N/C
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). **In email dated 4-17-12 verified OPID # with PHMSA**	x			
9.	191.23	Safety related condition reports **Avista has never had SRCR**	x			
10.	191.25	Filing the SRCR within 5 days of determination, but not later than 10 days after discovery **Avista has never had SRCR**	x			
11.	192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports **None**	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; **NONE FOR TRANSMISSION**	x			
14.		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. **NONE FOR TRANSMISSION**	x			
15.	480-93-200(1)(c)	Results in the evacuation of a building, or high occupancy structures or areas; **NONE FOR TRANSMISSION**	x			
16.	480-93-200(1)(d)	Results in the unintentional ignition of gas; **NONE FOR TRANSMISSION**	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; **NONE FOR TRANSMISSION**	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; **NONE FOR TRANSMISSION**	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 **NONE FOR TRANSMISSION**	x			
20.	480-93-200(2)	Telephonic Reports to UTC **Pipeline Safety Incident Notification 1-888-321-9146** (Within **24 hours**) for; **NONE FOR TRANSMISSION**	x			
21.	480-93-200(2)(a)	The uncontrolled release of gas for more than two hours; **NONE FOR TRANSMISSION**	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; **NONE FOR TRANSMISSION**	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 **NONE FOR TRANSMISSION**	x			
24.	480-93-200(2)(d)	A pipeline pressure exceeding the MAOP **NONE FOR TRANSMISSION**	x			

Comments:

			S	U	N/A	N/C
25.	480-93-200(5)	Written incident reports (within 30 days) including the following; **NONE FOR TRANSMISSION**				

26.	480-93-200(4)(a)	Name(s) and address(es) of any person or persons injured or killed, or whose property was damaged; **NONE FOR TRANSMISSION**	X			
27.	480-93-200(4)(b)	The extent of injuries and damage; **NONE FOR TRANSMISSION**	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; **NONE FOR TRANSMISSION**	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; **NONE FOR TRANSMISSION**	X			
30.	480-93-200(4)(e)	The date and time the gas pipeline company was first notified of the incident; **NONE FOR TRANSMISSION**	X			
31.	480-93-200(4)(f)	The date and time the ((operators')) gas pipeline company's first responders arrived on-site; **NONE FOR TRANSMISSION**	X			
32.	480-93-200(4)(g)	The date and time the gas ((facility)) pipeline was made safe; **NONE FOR TRANSMISSION**	X			
33.	480-93-200(4)(h)	The date, time, and type of any temporary or permanent repair that was made; **NONE FOR TRANSMISSION**	X			
34.	480-93-200(4)(i)	The cost of the incident to the ((operator)) gas pipeline company; **NONE FOR TRANSMISSION**	X			
35.	480-93-200(4)(j)	Line type; **NONE FOR TRANSMISSION**	X			
36.	480-93-200(4)(k)	City and county of incident; and **NONE FOR TRANSMISSION**	X			
37.	480-93-200(4)(l)	Any other information deemed necessary by the commission. **NONE FOR TRANSMISSION**	X			
38.	480-93-200(5)	Submit a supplemental report if required information becomes available **NONE FOR TRANSMISSION**	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** **NONE FOR TRANSMISSION**	X			

Comments:

40.	480-93-200(7)	**Annual Reports** filed with the commission no later than **March 15** for the proceeding calendar year	**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	X			
42.	480-93-200(7)(b)	Damage Prevention Statistics Report including the following;	X			
43.	480-93-200(7)(b)(i)	Number of gas-related one-call locate requests completed in the field;	X			
44.	480-93-200(7)(b)(ii)	Number of third-party damages incurred; and	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	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	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	x			
54.	192.243(c)	NDT procedures	x			
55.	192.243(f)	Total Number of Girth Welds	x			
56.	192.243(f)	Number of Welds Inspected by NDT	x			
57.	192.243(f)	Number of Welds Rejected	x			
58.	192.243(f)	Disposition of each Weld Rejected	x			
59.	480-93-080(1)(b)	Use of testing equipment to record and document essential variables	x			
60.	480-93-115(2)	Test leads on casings (without vents) installed after 9/05/1992 Section 5.14 page 11 for testing casing wo test lead. **Two casing on transmission without test leads. Both installed prior to 92. There is a job ready to be scheduled that may clear both as well as well as weld on test leads**	x			
61.	480-93-115(3)	Sealing ends of casings or conduits on Transmission lines and main **Section 3.42 sheet 5, transmission line installed prior to code. In Colville on Skidmore Rd dug up casing and at other dig locations on transmission have noted casing seals. Casing were installed with casing seal when installed in 1966.**	x			
62.	480-93-115(4)	Sealing ends (nearest building wall) of casings or conduits on services **NA, this transmission. It is address in O&M section 3.16 sheet 8**	x			
63.	192.303	Construction Specifications **Must sign pressure test documentation**	x			
64.	192.325	Underground Clearance	x			
65.	192.327	Amount, Location, Cover of each Size of Pipe Installed **For transmission Section 3.15 sheet 1. Installed with 36 inches minimum.**	x			

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

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: • Quality assurance • Girth welds • Depth of cover • Initial strength testing, and; • Interference currents? **AVISTA DOES NOT USE ALTERNATIVE METHOD**			x	
67.	480-93-160(1)	Detailed report filed 45 days prior to construction or replacement of transmission pipelines ≥ 100 feet in length **Section 2.12 sheet 4. When Avista installed the 12" in 2009 (first 3-4 miles is 19.9 SYMS making transmission start at start at Rutter Parkway and Indian Trail Rd)** **Gave notice to UTC for construction and proximity consideration.**	x			
68.	480-93-170(3)	Pressure Tests Performed on new and replacement pipelines	x			
69.	480-93-170(10)	Pressure Testing Equipment checked for Accuracy/Intervals (Manufacturers Recom or Operators schedule) **Section 5.21**	x			
70.	480-93-175(1)	Study prepared and approved prior to moving and lowering of metallic pipelines > 60 psig **No part of transmission moved or lowered**	x			
71.	192.455	Cathodic Protection **CP installed on transmission in 1966 when it was installed. CP test boxes were part of original construction. Verified with DIMP records.**	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 **Avista does not use previously used pipe of any kind**			X	
74.	192.14 (a)(3)	Correction of unsafe defects and conditions **Avista does not use previously used pipe of any kind**			X	
75.	192.14 (a)(4)	Pipeline testing in accordance with Subpart J **Avista does not use previously used pipe of any kind**			X	
76.	192.14 (b)	Pipeline records: investigations, tests, repairs, replacements, alterations (life of pipeline) **Avista does not use previously used pipe of any kind**			X	
77.	192.16	Customer Notification (**Verification – 90 days – and Elements**) **Other than the Kettle Plant no direct customers on Transmission. Pressure to before going to customers. Reviewed customer notification letter and New Gas Customer Report (a list of who the letter and information was sent to.)**	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 **O&M Review done annually. Information accumulated all year and incorporated at the end of the year. Reviewed Documentation**	x			
79.	192.603(b)	Abnormal Operations .605(c) **This transmission line is run in connection to a distribution line 192.605 (c)(5). Although Avista does have SCADA system that monitors transmission line. Operators receive alarms and alerts and can dispatch 1st responders. They cannot control the system.**	x			

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

OPERATIONS and MAINTENANCE RECORDS			S	U	N/A	N/C
80.	**192.603(b)**	Availability of construction records, maps, operating history to operating personnel .605(b)(3) **Yes, in O&M. All employees have access to maps and computers. However, any repairs prior to 11-2008 were not transferred to electronic maps (GIS) – they are on the old paper maps. Avista is aware this is a concern because employees currently use the GIS maps exclusively. Reviewed job for putting barrel on transmission line in 2000, it was not o the GIS maps.** **Elbow fittings and tees not on original as builts or maps and that is one of Avista's identified records gaps.**	x			
81.	192.603(b)	Periodic review of personnel work – effectiveness of normal O&M procedures .605(b)(8) **Management review of greens, which is the gas operating order for normal construction and trouble orders (first response)**	x			
82.	192.603(b)	Periodic review of personnel work – effectiveness of abnormal operation procedures .605(c)(4) **Management review of greens, which is the gas operating order for normal construction and trouble orders (first response)**	x			
83.		**Damage Prevention Program: This program was reviewed during the Colville Inspection 9-2012**				
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)**					
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 **58.1 miles of transmission in class 1, 12.56 miles of transmission in class 2 and 1.9 miles of transmission in class 3. Verified for current Avista Transmission line study**	x			
100.	192.605(a)	Confirmation or revision of MAOP. Final Rule Pub. 10/17/08, eff. 12/22/08. .611 **Based on .273 and 24000**	x			

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

		OPERATIONS and MAINTENANCE RECORDS	S	U	N/A	N/C
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) **2013 control room inspection to be schedule later. Reviewed procedure**	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:

		Public Awareness Program .616 PHMSA PA inspection conducted in 2012	S	U	N/A	N/C
	192.603(b)	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.

			S	U	N/A	N/C
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. **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.	192.603(b)	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)	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 Section 3.18 sheet 7 and 8 and reviewed previously. This is transmission and for the transmission line although prior to code was pressure tested. Pressure test practice was to test whole as built including laterals at the same time. However, back then the actual footage of pipe tested was not recorded so there is not absolute proof that laterals were included in pressure test.	x			
114.	.553(b)	Uprating **None on Transmission**	x			
115.	192.709	**Maximum Allowable Operating Pressure** (**MAOP**)				
116.		**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 the following: .619				
118.	.709	**Design pressure of the weakest element, .619(a)(1) Amdt, 192-103 pub. 06/09/06, eff. 07/10/06** **6-11 Avista started a project to review transmission. At that time they divided transmission line in to 98 segments. For every segment there is a folder with copies of original as built, MAOP doc, and pressure test.** • **Avista using 24000 for yield strength.**	x			

<table>
<tr><td>119.</td><td rowspan="3">.709</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

The transmission line was pressure tested and records are available. Lateral on as built, chart for pressure test included laterals. There is nothing in writing to state laterals pressure tested at same time but they were the only component to test against. Believe all laterals were included in pressure test but cannot document. Tested to 700, 1.4 was practice at the time (1966) because of no code. It hydro tested in 4 segments. Spokane to Chewelah 8-27-66, Chewelah to Colville 10-18-66, Colville to Kettle Falls 10-16-66 and was tested 750 and 4th test to Boise Cascade Mill was 10-24-66.
<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>.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.

Avista has original pressure test for transmission line – Laterals tested but no footage. This pressure test was conducted to the standard and practices of 1966.</td><td>x</td><td></td><td></td><td></td></tr>
<tr><td>121.</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
Avista does not do alternative MAOP.</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
Colville's last odorant test site is at the end of the transmission line. Reviewed</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
Colville has 5 odorant test sites the last one is at the end of the transmission line –ok. Spokane injects odorant at 9 mile Gate Station #8008. In Spokane district the test sites are all in the distribution system and odorant ok . Avista reviews system annually to ensure they are always at extremity of system. In Spokane district there are 11 odor test sites.</td><td>x</td><td></td><td></td><td></td></tr>
</table>

124.	480-93-015(3)	Prompt action taken to investigate and remediate odorant concentrations not meeting the minimum requirements **Avista O&M procedure is to immediately take 2nd read if 1st read not good. Most of the time 2nd read is good. When the 2nd read is not good, procedure is to call in Pressure Control man to adjust odorizer. In Nov 2009 when the new 12" installed at gate station had low reads for month due to pickling of line. That month Avista did 6 extra odor reads, while line was pickling**	x			
125.	480-93-015(4)	Odorant Testing Equipment Calibration/Intervals (Annually or Manufacturers Recommendation) **Odometer has 2 yr calibration.** Reviewed calibration dates. **In Spokane 2009 to 2011 which is ok but then sent back to manufacture because battery not operating properly. First glance it appears that it was calibrated late but was not.**	x			
126.	480-93-124(3)	Pipeline markers attached to bridges or other spans inspected? **1/yr(15 months) O&M Section 3.15. No bridges on transmission line.**	x			
127.	480-93-124(4)	Markers reported missing or damaged replaced within **45 days?**	x			

Comments:

128.	480-93-185(1)	Reported gas leaks investigated promptly/graded/record retained **Investigated promptly. Avista does not carry leaks more than 12 months.**	x			
129.	480-93-185(3)	Leaks originating from a foreign source reported promptly/notification by mail/record retained **WAC date 6-30-08. No foreign leaks on Transmission since then.**	x			
130.	480-93-187	Gas Leak records From 1966 to 1972 (code effect) Leak Surveys were conducted per 72. **192 only requires that leak survey records be kept for 5 years. Avista has at least 20 years' worth.**	x			
131.	480-93-188(1)	Gas Leak surveys See question 133. Reviewed 12-2012 leak found on map 12CCD-4-16X. Reviewed Leak report generated from map, it is # 12-2102. It is 3 part form (blue, yellow and white). Blue to construction which in this case is Colville, Yellow to compliance tech and original remains in Leak Survey Dept. Colville takes the blue and completes and sends to Linda Burger to review for DIMP information then to Shawn, leak survey dept . and he files when complete To ensure that all leaks are fixed, Shawn sends annual report to managers to make sure completed. Compliance tech is in loop and has weekly conversations with district manager. Avista does not carry leaks more than 12 months..	x			
132.	480-93-188(2)	Gas detection instruments tested for accuracy/intervals (Mfct rec or monthly not to exceed 45 days) **Flame ionization have SN and Calibration on leak survey form and are calibrated daily if done by contractor. FI and CGI calibrated monthly in each district. Doc on any leak form or map.**	x			

133.	480-93-188(3)	Leak survey frequency **(Refer to Table Below)** **Transmission done annually. Reviewed 2009 thru 2012. Spokane has records back to 2007 and prior to that leak surveys are archives. Leak Survey in housing development done twice annually because of class 3. Line is broken down between Colville and Spokane districts. These Colville Transmission leak survey areas are called Colville transmission 1and 2. Also Reviewed Spokane lines, in 2010 installed the new 12" to prevent a HCA area. 19.9 % SYMS. Deer Lake is separation for Spokane and Colville districts. For Spokane only the transmission line is transmission all laterals are HP distribution. Leak surveyed at the same time. Also Spokane HP and Transmission leak surveys done at the same time. Leaks are found but in Spokane for 2012 there were no transmission leaks, there were 12 HP leaks (all were above ground).** **Procedure for map error. Noted on question on map. Leak survey folds copy leak survey form and send to GIS editing group and they have 6 months to correct map. Mapping sends someone out into field to verify there is a mapping error.** **Fittings not shown on map prior to DIMP. The barrel repair mapped on paper not on GIS map. Paper maps were used as the basis for the electronic GIS mapping system. Fittings are missing from maps**	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 O&M requires and Reviewed in Colville did road rebuild leak survey on Blue Creek Rd. **In Colville district a shorted casing on Stephen Rd N of Clayton. This short found 8-14-2012 and has had the initial leak survey will be done as required. They are going to clear one side, job in, but job may not eliminate short and casing and if that is the case will be leak surveyed twice annually.**	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 Reviewed in Colville did road rebuild leak survey on Blue Creek Rd.	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 **All gas leak survey records kept in Spokane.**	x			
139.	480-93-188(6)	Leak Survey Program/Self Audits Reviewed all requirements on Leak Survey maps	x			

140.	192.709	Patrolling (**Refer to Table Below**) .705 *.709 a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.* **Whole line is flown annually, in Oct segments walked. 2nd patrol if for highway and RR crossings.** **Spokane** **1st one is at mile marker 01 to north side of water crossing at Little Spokane mile marker #4** **2nd one is at the w side of 395 to east side of 395 800 ft s of 395 and Stephenson and 150 feet west of marker that crosses aerial marker 27** **3rd one is at E side of 395 E to pipeline mile marker 27/e side of 395** **4th Pipeline marker 27 South to South side of RR crossing to Vent** **Colville** **1. US 395 crossing south of Chewlah approx. 800 feet s of Logan Rd.** **2. BNRR crossing vicinity of us 395 crossing** **3. WA state hwy 25 crossing - THIS ONE IS DONE 4 TIMES A YEAR, CLASS 3** **4th. City of Kettle Falls (Juniper street to E Evergreen drive)** **5th. Boise Plywood plant vicinity** **6th. BNRR crossing west of Kettle Falls Generation approx. 600 feet w of Peachcrest and Boise Rd.**	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

Early in year do the class 3 areas and with the annual leak survey done again later in the year meeting the 2 x a year. April and in Oct do the annual HP leak survey. Meet the 7 ½ requirement

142.	192.605(b)	Abandoned Pipelines; Underwater Facility Reports .727(g) **None for transmission**	x			
143.	192.709	Compressor Station Relief Devices (**1 per yr/15 months**) .731(a) **Avista does not have compressor station(s)**			x	
144.	192.709	Compressor Station Emergency Shutdown (**1 per yr/15 months**) .731(c) **Avista does not have compressor station(s)**			x	
145.	192.709	Compressor Stations – Detection and Alarms (**Performance Test**) .736(c) **Avista does not have compressor station(s)**			x	
146.	192.709	Pressure Limiting and Regulating Stations (**1 per yr/15 months**) .739 **Only one Regulator Station called Antler Rd Reg Station 715 (worker monitor). It has been in by pass mode since 1997. It had annual maintenances every year. In 2012, Avista decided to only do atmospheric 3 year eval on station, since it has not been in use.**	x			
147.	192.709	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**) .743 **Although there are many regulator stations off the transmission line they are only HP not transmission and therefore no capacity checks required.**	x			

Comments:

			S	U	N/A	N/C
148.	192.709	Valve Maintenance (**1 per yr/15 months**) .745 Review **Emergency valves on Transmission line are 5 valves in Colville and 5 in Spokane. There are other emergency valves around stations but they are considered distribution because they are not 20% SMYS**	x			
149.	192.709	Vault Maintenance (≥**200 cubic feet**)(**1 per yr/15 months**) .749 **No vaults in WA**			x	
150.	192.603(b)	Prevention of Accidental Ignition (hot work permits) .751 **O&M 3.17 and is an OQ task in section 5.31 Appendix A** **Use Warning tape when welding in hole and traffic control signs,**	x			
151.	192.603(b)	Welding – Procedure .225(b) RECORDS	x			
152.	192.603(b)	Welding – Welder Qualification .227/.229 RECORDS	x			
153.	192.603(b)	NDT – NDT Personnel Qualification .243(b)(2) RECORDS	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) **BOTTOM THIRD OF PATROLLING FORM HAS PLACE TO MARK IF HCA found. Also the last check boxes on Patrol form are only for transmission. Serviceman looks for new construction, HOS and population**	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 **Reviewed Gary Douglas NACE and Bob Larson NACE** **O&M Section 5.3.1** **Gary works with design engineering for all cp items. Gary has isolated the transmission and HP system from the distribution. On transmission (including HP laterals) there are 56 test sites for Colville district and 17 for Spokane district.**	x			
159.	192.455(a)(2)	CP system installed on and operating within 1 yr of completion of pipeline construction *(after 7/31/71)* **Only time they do steel is for HP. Did one on Bruce and Stoneman Rd and cp always installed during construction**	x			

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

CORROSION CONTROL RECORDS			S	U	N/A	N/C
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) **No short sections**	x			
161.	192.491	Maps or Records .491(a) **Avista has maps, updated in 6 months. CP records are kept for 3 years in the office and the older ones are archived and everything from 2005 to current are on the computer 2005 to 2009 on spread sheets and 2009 on CLM Compliance List Manager system used by compliance techs**	x			
162.	192.491	Examination of Buried Pipe when Exposed .459 **Prior to 2010 records are on paper and archived. 2010 forward are on CLM. Exposed pipe for kettle plant 2 years ago for new valves, cp test leads at Skidmore Rd, intersection of new 12" and old 8" located at Indian Trail and Rutter Parkway. These records were reviewed in the Colville inspection**	x			
163.	480-93-110(8)	CP test reading on all exposed facilities where coating has been removed **ok**	x			
164.	192.491	Rectifier Monitoring (**6 per yr/2½ months**) .465(b) All Kettle transmission rectifiers reviewed during Colville Standard inspection (2 for Transmission). Reviewed all rectifier for Spokane transmission, there ais one rectifier on Bernhill Rd. Reviewed readings and dates.	x			
165.	192.491	Interference Bond Monitoring – Critical (**6 per yr/2½ months**) .465(c) **No bonds**	x			
166.	192.491	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**) .465(c) **none**	x			
167.	192.491	Prompt Remedial Actions .465(d) **If find low cp, write work order and have 90 days to figure out. Example is Hafer Rd, low read found-.364, work order 3850, 1 -9-2012. I t was found shut off. Also at time Addy and Hafer Rd found off, most likely lightning strike or power surge etc. – Main breakers still on. Doing its Job.**	x			
168.	192.491	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) .465(e) **No unprotected pipe either transmission or distribution**	x			
169.	192.491	Electrical Isolation (**Including Casings**) .467 **Use thinsultor and isolation at every regulator and at meter. Casings take annual read and ensures isolation. NOTE: division of transmission line work is at N Deer Lake Rd. One shorted casing in Colville found in 2012 and in Spokane none – NOTE that although this is called Colville short it is actually in the Spokane District** **In Colville district a shorted casing on Stephen Rd N of Clayton. This short found 8-14-2012 and has had the initial leak survey will be done as required. They are going to clear one side, job in, but job may not eliminate short and casing and if that is the case will be leak surveyed twice annually.**	x			
170.	480-93-110(2)	Remedial action taken within 90 days (Up to 30 additional days if other circumstances. Must document) .465(d) **Yes, see question 167**	x			
171.	480-93-110(3)	CP Test Equipment and Instruments checked for Accuracy/Intervals (Mfct Rec or Opr Sched) **All equipment calibrated in Dec. CP dept calibrates all cp equipment half-cell, voltmeter for all districts. Reviewed Calibration worksheet. Half cells must be within 5mv of test cell if not, taken apart and cleaned and retest. If still not good replace. Reviewed 2011, 2010 and 2009. For Volt Meter to be within 50mv of test tinker racer. Looked at Bob Larsen, Ken Sampson and Mike Ressa for Transmission.**	x			
172.	480-93-110(5)	Casings inspected/tested annually not to exceed fifteen months **System 28, is the Spokane side of Transmission, 3 in Spokane. Requirement is 100 mill volt or .1 difference or greater. Reviewed crossing at Rutter south of reg station 53.** **35 casing on Colville side of transmission system. All ok per Colville distribution audit. There is one shorted casing on the Colville side, 90 day leak survey done and will start 2x a year.**	x			

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

CORROSION CONTROL RECORDS			S	U	N/A	N/C
173.	480-93-110(5)(a)	Casings w/no test leads installed prior to 9/05/1992. Demonstrate other acceptable test methods **None installed on transmission line prior to 92. O&M section 5.14, page 11 of 14 address casings w/no test leads. There is one in WA**	x			
174.	480-93-110(5)(b)	Possible shorted conditions – Perform confirmatory follow-up inspection within 90 days **Yes Colville short is example. 90 day done**	x			
175.	480-93-110(5)(c)	Casing shorts cleared when practical **On Colville casing can only dig one side and there is work order to do it. If this does not clear shorts it will be leak survey 2x year.**	x			
176.	480-93-110(5)(d)	Shorted conditions leak surveyed within 90 days of discovery. Twice annually/7.5 months **See above**	x			
177.	192.491	Interference Currents .473 **Transmission none**	x			
178.	192.491	Internal Corrosion; Corrosive Gas Investigation .475(a) **No corrosion gas per contract with Williams**	x			
179.	192.491	Internal Corrosion; Internal Surface Inspection; Pipe Replacement .475(b) **None**	x			
180.	192.491	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems .476(d) **None, O&M 2.32**	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 Only above ground transmission pipe at Antler Rd Reg station 715 and Kettle Plant boiler meter, industrial meter 3415. Avista does not look under supports for atmospheric corrosion. This was observed during crew inspection 9-11-12 at Peach crest station. Supports handled in concerns handled under Pullman Clarkston Inspection	x			
183.	192.491	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions .483/.485. **All repairs require coating O&M 3.32**	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			

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

PIPELINE INSPECTION (Field)			S	U	N/A	N/C
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:** 10-24-2012

Comments:

COMPRESSOR STATIONS INSPECTION (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) x **AVISTA DOES NOT HAVE ANY COMPRESSOR STATIONS FOLLOWING ARE NA**		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:				

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

COMPRESSOR STATIONS INSPECTION (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) x AVISTA DOES NOT HAVE ANY COMPRESSOR STATIONS FOLLOWING ARE NA		S	U	N/A	N/C
	- 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	
.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	

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

Comments:
Field notes

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

AVISTA DOES NOT USE ALTERNATIVE MAOP PROCEDURES FOLLOWING ARE NA

192.620	**Alternative MAOP Procedures and Verifications**	**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	

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

192.620	Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
	(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	
	(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	

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

192.620	Alternative MAOP Procedures and Verifications	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			X	
.620(e)				X	
	(2) Procedure for establishing and maintaining set points for SCADA				

Comments:

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

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: