Abbreviated Form 1
STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		Post Inspection Memorandum	
Inspector/Submit Date:	Scott Rukke & David Cullom/ 6/30/2010	**Chief Eng/Review Date:**	Joe Subsits/September 8, 2010
		Peer Review/Date:	
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)		
Name of Operator: Williams Gas Pipeline West		**OPID #:** 13845
Name of Unit(s): Redmond District		**Unit #(s):** 3675
Records Location: Redmond District Office		**Activity #**
Unit Type & Commodity: Interstate Natural Gas Transmission		
Inspection Type: Standard Inspection	**Inspection Date(s):** June 7 to June 10, 2010	
PHMSA Representative(s): Scott Rukke, David Cullom - WUTC		**AFO Days:** 8

Company System Maps (copies for Region Files):

Validate SMART Data (components, miles, etc): ☐ **Acquisition(s), Sale or New Construction** (submit SMART update): ☐

Validate Additional Requirements Resulting From Waiver(s) or Special Permit(s):

Summary:

A review of operations and maintenance records was conducted at the Redmond district office. Field visits were made to the Snohomish compressor station, the Sumner compressor station and the Tumwater compressor station. Field visits were made to the Black Diamond Williams/PSE gate station, the North Seattle Lateral and regulator/relief station, the South Seattle Lateral and Williams/PSE gate station. The South Seattle odorizer station was inspected and the relief valve set points were tested.

Various emergency block valves, both manually operated and gas/hydraulically operated, were inspected and operated along the right of way and at all compressor stations. The North Seattle Lateral relief valve set points were tested. The South Seattle Lateral, Williams/PSE gate station relief valve set points were tested. The North Tacoma Gate Station was inspected. The North Puyallup Gate Station was inspected and the relief valve set points were tested.

Fire eyes, gas detectors and ESD's were tested at all compressor stations and all operated as designed. Ventilation fans activated at the Tumwater compressor station during both gas detector tests on Unit A.

Cathodic protection readings were taken at all compressor stations, all meter and gate stations and at all stops along the pipeline right way. All CP readings indicated proper cathodic protection.

The rectifier located at the Black Diamond Williams/PSE gate station was inspected and tested.

Findings:

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Findings:
No issues or violations were noted during this inspection.

The following notes are in regards to observations made but do not constitute probable violations at this time. Williams has agreed to remediate these items.

The North Tacoma Lateral was recently reclassified as being predominantly in a class 3 location which requires odorization. Currently no odorization is provided. Williams has budgeted for the installation of an odorizer. This should be verified during the next inspection cycle. As of 6/30/2010, this job is in for permit and should be completed by the first quarter of 2011.

The relief valve pilot at the South Seattle Lateral Williams/PSE gate station was stroked and tested for setpoint several times. During one test, the pilot opened prematurely then closed and opened at proper setpoint. Williams plans to have both pilots for the dual run relief valves rebuilt within the next 2 weeks. This station is also designed and operated as a worker monitor setup and the dual relief valve downstream of the regulators is redundant over pressure protection so no issues were noted.

Two flange bolts on relief run #1 were too short to properly engage the connecting nuts fully. This was due to the addition of a mounting support plate between the nuts and the flanges. Williams plans to change out the 2 bolts ASAP so no issues were noted. The relief valve flanges with the short bolts is a redundant over pressure protection device downstream of a worker monitor regulator so no issues were noted. As of 6/30/2010 these bolts have been changed out.

Williams' DetectoPak Hydrogen Flame Ionization leak detection units, used to conduct instrumented leak surveys in class 3 areas, is calibrated every 2 years per the Redmond district manager. A calibrated gas operational test is conducted prior to each survey, but at the time of this inspection was not recorded. Williams immediately revised their leak survey forms to record the operational test. It was also recommended that Williams contact the DetectoPak manufacturer to ascertain if every 2 years meets the calibration requirements. DetectoPak's written calibration recommendations were unclear and appeared to allow operators wide latitude in calibration frequencies so no issues were noted.

A Fisher regulator at the North Puyallup Gate Station was mounted with the relief port in a horizontal position. This could, in extreme weather conditions, possibly allow rain to accumulate internally in the regulator and prevent proper operation. The regulator is installed to regulate fuel gas to the station heater. Williams agreed to install a 90 degree elbow and screen to prevent any accumulation of water so no issues were noted. As of 6/30/2010, a weather proof elbow has been installed on the vent.

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Name of Operator:	Williams Gas Pipeline West		
OP ID No. [1] 13845		**Unit ID No.** [1] 3675	
HQ Address:		**System/Unit Name & Address:** [1]	
Williams Gas Pipeline West 2800 Post Oak Boulevard MD-21 Houston, TX 77056		Williams Gas Pipeline West Redmond District 22909 Redmond Fall City Road Redmond, WA 98053	
Co. Official:	Randy Barnard, VP Operations,	**Activity Record ID No.:**	
Phone No.:	(713) 215-2375	**Phone No.:**	(360) 988-2261
Fax No.:	Fax (713) 215-4269	**Fax No.:**	(360) 988-9105
Emergency Phone No.:		**Emergency Phone No.:**	(360) 972-7733

Persons Interviewed	Title	Phone No.
Grant Jensen	District manager	425-868-1010
Frances Roemer	ADM	425-868-1010
Ron Mertz	Senior Operations Technician	206-915-0589
Jason Lambert	Pipeline Safety Specialist	801-584-6657
Lauri Duncombe	Pipeline Safety Engineer	801-584-6509
Jeffrey Pollack	Senior Integrity Spec	206-890-6259
Michael Wolfe	Pipeline Integrity Specialist	206-369-7573
Justin Reynolds	Team Lead Pipeline Integrity	509-290-1918

PHMSA Representative(s) [1] Scott Rukke, David Cullom WA State	**Inspection Date(s)** [1] June 7 – June 10, 2010
Company System Maps (Copies for Region Files): Redmond and Salt Lake City	

Unit Description:
The Williams Redmond District is bordered to the north by the Sumas District and is bordered to the south by the Battleground District. The district consists of 214 miles of right of way, 64 miles are in class 3 location. There are 37 meter stations in the district. There are three compressor stations in the district. Snohomish Compressor Station has two 13,000 HP Solar Mars 90 units, Sumner has two 13,000 HP Solar Mars 90 units. Tumwater has a 1200 HP Saturn unit and one Centaur 4500 HP unit. The 26-inch line is idle with the exception of 17 miles from Lake Stevens to the Snohomish Compressor Station and 25 miles from the Fort Lewis Compressor Station to the District boundry near the Thurston/Lewis County line. The 36-inch loop consists of 12 miles from the Snohomish Compressor Station to Sammamish and 19 miles from the Fort Lewis Compressor Station to the Shelton-Olympia takeoff. The 16" Everett Delta lateral was installed in late 2004 and a meter station was added. The lateral is about 17 miles long. PSE operates the lateral. The Fort Lewis mobile compressor station has been disconnected from the pipeline system.

Portion of Unit Inspected: [1]
A review of operations and maintenance records was conducted at the Redmond district office. Field visits were made at the Snohomish compressor station, the Sumner compressor station and the Tumwater compressor station. Field visits were made to the Black Diamond Williams/PSE gate station, the North Seattle Lateral and regulator/relief station, the South Seattle Lateral and Williams/PSE gate station. The South Seattle odorizer station was inspected and the regulator and relief valve set points were tested.
Various emergency block valves, both manually operated and gas/hydraulically operated, were inspected and operated along the right of way and at all compressor stations. The North Seattle Lateral relief valve set points were tested. The South Seattle Lateral, Williams/PSE gate station relief valve set points were tested. The North Tacoma Gate Station was inspected. The North Puyallup Gate Station was inspected and the relief valve set points were tested.
Fire eyes, gas detectors and ESD's were tested at all compressor stations and all operated as designed. Ventilation fans activated at the Tumwater compressor station during both das detector tests on Unit A.
Cathodic protection readings were taken at all compressor stations, all meter and gate stations and at all stops along the pipeline right-of- way. All CP readings indicated proper cathodic protection.

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

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For gas transmission pipeline inspections, the attached evaluation form should be used in conjunction with 49 CFR 191 and 192 during PHMSA inspections. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/16/05 and 03/19/10.

This form may be used in lieu of Form 1 if the operator's procedures were inspected by the region within the prior year, or if the operator has received a Team O&M Inspection within the past five years.

Operator's procedures reviewed during the previous inspection (enter previous inspection date below) may be marked with a "1" in the N/C column.

(check applicable box and enter inspection date)

	Team inspection of the operator's O & M Manual was performed:	Date:	2005
	Region inspection of the operator's O & M Manual was performed:	Date:	

49 CFR PART 192

.605(a)		CHANGE in CLASS LOCATION PROCEDURES	S	U	N/A	N/C
*	.611	Confirmation or revision of MAOP. Final Rule Pub. 10/17/08, eff. 12/22/08.	X			

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

		PUBLIC AWARENESS PROGRAM PROCEDURES (Also in accordance with API RP 1162)	S	U	N/A	N/C
.605(a) *	.616	Public Awareness Program also in accordance with API RP 1162. Amdt 192-99 pub. 5/19/05 eff. 06/20/05.				
	.616(d)	The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:				
		(1) Use of a one-call notification system prior to excavation and other damage prevention activities;	X			
		(2) Possible hazards associated with unintended releases from a gas pipeline facility;	X			
		(3) Physical indications of a possible release;	X			
		(4) Steps to be taken for public safety in the event of a gas pipeline release; and	X			
		(5) Procedures to report such an event (to the operator).	X			
	.616(e)	The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.	X			
	.616(f)	The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports gas.	X			
	.616(g)	The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area?	X			
	.616(h)	IAW API RP 1162, the operator's program should be reviewed for effectiveness within four years of the date the operator's program was first completed. For operators in existence on June 20, 2005, who must have completed their written programs no later than June 20, 2006, the first evaluation is due no later than **June 20, 2010**.	X			

Comments:

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Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

1822.30.1Public Agency Contacts
1822.30.2 Record of puiblic Education
Interoffice memo 2008 Public Education Program for District managers
Interoffice memo Sept 9, 2009 Public Education Program for Affected Managers
Public Awareness Evaluation and Effectiveness.

.605(a)		MAOP PROCEDURES	S	U	N/A	N/C
		Note: If the operator is operating under a Special Permit, a Waiver or 192.620, the inspector needs to review the special conditions of the Special Permit, Waiver or refer to Attachment 1 for additional .620 requirements.				
	.619	Establishing **MAOP** so that it is commensurate with the class location				X
		MAOP cannot exceed the lowest of the following:				
*		(a)(1) Design pressure of the weakest element, Amdt. 192-103 pub. 06/09/06, eff. 07/10/06				X
*		(a)(3) The highest actual operating pressure to which the segment of line was subjected during the 5 years preceding the applicable date in second column, unless the segment was tested 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.**				X

Pipeline segment	Pressure date	Test date
--Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006. -- Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines.	July 1, 1976.	July 1, 1971.
All other pipelines.	July 1, 1970.	July 1, 1965.

*		(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.**				X
*	.620	Refer to Attachment 1 for additional Alternative MAOP requirements. Amdt. 192-111 pub. 11/30/09, eff. 1/29/2010.				

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.
Record keeping procedure

Not operating under these conditions.

.605(b)		RECORD KEEPING PROCEDURES	S	U	N/A	N/C
	.709	Records must be maintained:				
		(a) Repairs to the pipe – **life of system**	X			

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.605(b)	RECORD KEEPING PROCEDURES	S	U	N/A	N/C
	(b) Repairs to "other than pipe" – **5 years**	X			
	(c) Operation (Sub L) and Maintenance (Sub M) patrols, surveys, tests – **5 years** or until next one	X			

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.
Procedures, 70.14.00 and 70.14.01
Procedure 0192 form number
Forms 45-5 years, 92-life and 231-life

.605(b)		ABANDONMENT or DEACTIVATION of FACILITIES PROCEDURES	S	U	N/A	N/C
*	.727 (g)	Operator must file reports upon abandoning underwater facilities crossing navigable waterways, including offshore facilities. Amdt. 192-103 corr. pub 02/01/07, eff. 03/05/07.			X	

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.
No offshore in unit.

.605(b)		COMPRESSOR STATION PROCEDURES	S	U	N/A	N/C
*	.735	(b) Tank must be protected according to **NFPA #30;** Amdt 192-103 pub. 06/09/06 eff. 07/10/06.				X

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.
Checked during Spokane North and South

.13(c)		WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A	N/C
*	.225	(a) Welding procedures must be qualified under **Section 5 of API 1104** or **Section IX of ASME Boiler and Pressure Code** by destructive test. Amdt. 192-103 pub 06/09/06, eff. 07/10/06.	X			
	Note: Alternate welding procedures criteria are addressed in API 1104 Appendix A, section A.3.					
*	.227	(a) Welders must be qualified by **Section 6 of API 1104 (19th Ed., 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008)** or **Section IX of ASME Boiler and Pressure Code** (2004 ed. Including addenda through July 1, 2005) See exception in .227(b). Amdt. 192-103 pub 06/09/06, eff. 07/10/06; Amdt. 192-103 corr. Pub 02/01/07 eff. 03/05/07; Amdt 195-91 Pub. 4/14/09 eff. 4/14/09. *Note: Operator's procedures must specify the edition of API 1104 they are using. Operator may not use both editions, and procedures must be consistent with the edition used.*	X			

Comments:

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Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.
Nw Pipeline Qualification records for 1/2010

.273(b)		JOINING of PIPELINE MATERIALS	S	U	N/A	N/C
*	.283	Qualified joining procedures for plastic pipe must be in place. Amdt. 192-103 pub. 06/09/06, eff. 07/10/06.			X	

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

No plastic.

.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
*	.476	Systems designed to reduce internal corrosion (a) New construction Final Rule Pub. 4/23/07, eff. 5/23/07.				1
*		(b) Exceptions – offshore pipeline and systems replaced before 5/23/07 Final Rule Pub. 4/23/07, eff. 5/23/07.				1
*		(c) Evaluate impact of configuration changes to existing systems Final Rule Pub. 4/23/07, eff. 5/23/07.				1

Comments:
Note 1: This item was reviewed in the O & M Manual since the effective date of the applicable amendment.

Checked during Spokane North and South.

	PIPELINE INSPECTION (Field)	S	U	N/A	N/C
.179	Valve Protection from Tampering or Damage	X			
.463	Cathodic Protection	X			
.465	Rectifiers	X			
.476	Systems designed to reduce internal corrosion				X
.479	Pipeline Components Exposed to the Atmosphere	X			
.605	Knowledge of Operating Personnel	X			
.612 (c) (2)	Pipelines exposed on seabed (Gulf of Mexico and Inlets): Marking			X	
613(b), .703	Pipeline condition, unsatisfactory conditions, hazards, etc.	X			
.707	ROW Markers, Road and Railroad Crossings	X			
.719	Pre-pressure Tested Pipe (**Markings and Inventory**)				X
.739/.743	Pressure Limiting and Regulating Devices (spot-check field installed equipment vs. inspection records)	X			
.745	Valve Maintenance	X			
.751	Warning Signs	X			
.801 - .809	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			

Comments:

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Comments:
Internal corrosion procedures checked in Spokane North and South district
No gulf pipelines in unit
Stored pipe not checked.

	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")	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			

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	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")	S	U	N/A	N/C
.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			
.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 LDC tied directly to station ESD's
No unattended compressors in district.

	CONVERSION TO SERVICE PERFORMANCE and RECORDS	S	U	N/A	N/C
.14 (a)(2)	Visual inspection of right of way, aboveground and selected underground segments No Converted lines.			X	
(a)(3)	Correction of unsafe defects and conditions No Converted lines.			X	
(a)(4)	Pipeline testing in accordance with Subpart J No Converted lines.			X	
(b)	Pipeline records: investigations, tests, repairs, replacements, alterations (life of pipeline) No Converted lines.			X	

	REPORTING PERFORMANCE and RECORDS	S	U	N/A	N/C
191.5	Telephonic reports to NRC (800-424-8802)	X			
191.15	Written incident reports; supplemental incident reports (DOT Form RSPA F 7100.2)	X			
191.17 (a)	Annual Report (DOT Form RSPA F 7100.2-1)	X			
191.23	Safety related condition reports	X			
191.27	Offshore pipeline condition reports			X	
192.727 (g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports	X			

	CONSTRUCTION PERFORMANCE and RECORDS	S	U	N/A	N/C
.225	Test Results to Qualify Welding Procedures				X
.227	Welder Qualification				X
.241 (a)	Visual Weld Inspector Training/Experience				X
.243 (b)(2)	Nondestructive Technician Qualification				X
(c)	NDT procedures				X
(f)	Total Number of Girth Welds				X
(f)	Number of Welds Inspected by NDT				X
(f)	Number of Welds Rejected				X
(f)	Disposition of each Weld Rejected				X
.303	Construction Specifications				X
.325	Underground Clearance				X

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	CONSTRUCTION PERFORMANCE and RECORDS	S	U	N/A	N/C
.327	Amount, Location, Cover of each Size of Pipe Installed				X
.328	If the pipeline will be operated at the alternative MAOP standard calculated under 192.620 (80% SMYS) refer to PHMSA Form 5 (Construction) for additional construction requirements				X
.455	Cathodic Protection				X

		OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS	S	U	N/A	N/C
.16		Customer Notification (**Verification – 90 days – and Elements**)			X	
.603(b)	.605(a)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**)	X			
.603(b)	.605(c)	Abnormal Operations			X	
.603(b)	.605(b)(3)	Availability of construction records, maps, operating history to operating personnel	X			
.603(b)	.605(b)(8)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.603(b)	.605(c)(4)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.709	.609	Class Location Study (**If Applicable**)	X			
.603(b)	.612(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			X	
.709	.614	Damage Prevention (**Miscellaneous**)	X			
.603(b)	.615(b)(1)	Location Specific Emergency Plan	X			
.603(b)	.615(b)(2)	Emergency Procedure training, verify effectiveness of training	X			
.603(b)	.615(b)(3)	Employee Emergency activity review, determine if procedures were followed.			X	
.603(b)	.615(c)	Liaison Program with Public Officials	X			
.603(b)	.616	Public Awareness Program				
	.616(e & f)	Documentation properly and adequately reflects implementation of operator's Public Awareness Program requirements - Stakeholder Audience identification, message type and content, delivery method and frequency, supplemental enhancements, program evaluations, etc. (i.e. contact or mailing rosters, postage receipts, return receipts, audience contact documentation, etc. for emergency responder, public officials, school superintendents, program evaluations, etc.). See table below:	X			

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
Stakeholder Audience (Gathering Line Operators)	**Baseline Message Frequency**
Residents and Places of Congregation	Annual
Emergency Officials	Annual
Public Officials	3 years
Excavators 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.	

	.616(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area.	X			
	.616(h)	Effectiveness Review of operator's program.	X			
.517		Pressure Testing	X			
.553(b)		Uprating			X	
.709	.619 / .620	Maximum Allowable Operating Pressure (**MAOP**) If the pipeline is operating at the alternative MAOP under 192.620 (80% SMYS), refer to Attachment 1 for additional requirements.			X	

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		OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS	S	U	N/A	N/C
.709	.625	Odorization of Gas	X			
.709	.705	Patrolling (**Refer to Table Below**)	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)

.709	.706	Leak Surveys (**Refer to Table Below**)	X			

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

* Leak **detector equipment** survey required for lines transporting un-odorized gas.

.709	.731(a)	Compressor Station Relief Devices (**1 per yr/15 months**)	X			
.709	.731(c)	Compressor Station Emergency Shutdown (**1 per yr/15 months**)	X			
.709	.736(c)	Compressor Stations – Detection and Alarms (**Performance Test**)	X			
.709	.739	Pressure Limiting and Regulating Stations (**1 per yr/15 months**)	X			
.709	.743	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**)	X			
.709	.745	Valve Maintenance (**1 per yr/15 months**)	X			
.709	.749	Vault Maintenance (**≥ 200 cubic feet**)(**1 per yr/15 months**)			X	
.603(b)	.751	Prevention of Accidental Ignition (hot work permits)	X			
.603(b)	.225(b)	Welding – Procedure				X
.603(b)	.227/.229	Welding – Welder Qualification	X			
.603(b)	.243(b)(2)	NDT – NDT Personnel Qualification				X
.709	.243(f)	NDT Records (**Pipeline Life**)				X
.709	Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**)					X
.807(b)	Refer to PHMSA Form # 15 to document review of operator's employee covered task records					

Comments: 181 form is used for suggested procedural changes.
Reviewed one notice to NRC from 9/16/2009 regarding a potential leak that was found to not be gas. This notice was later withdrawn.
Reviewed welder requalification records. There were no other jobs performed that required NDT since the last inspection.
Reviewed Mock Emergency 2009 Green River Flooding.
Reviewed 2008 Mock Emergency Bonb Threat
Reviewed 10.17.00.10 Baseline message frequency policy.
Reviewed 2/2/09 to present odorant level readings for the South Seattle lateral.
No offshore pipelines.
No conversion to service
No large construction jobs with records from last inspection
No services requiring downstream piping notification
No abnormal operations
No Gulf of Mexico facilities
No emergency reviews required
No uprating
Not operating up to 80%
No vaults
Procedures manual revision date matrix
No uprates

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Comments: 181 form is used for suggested procedural changes.

	CORROSION CONTROL PERFORMANCE and RECORDS		S	U	N/A	N/C
.453	CP procedures (system design, installation, operation, and maintenance) must be carried out by qualified personnel		X			
.491	.491(a)	Maps or Records	X			
.491	.459	Examination of Buried Pipe when Exposed	X			
.491	.465(a)	Annual Pipe-to-soil Monitoring (**1 per yr/15 months**) or short sections (**10 % per year, all in 10 years**)	X			
.491	.465(b)	Rectifier Monitoring (**6 per yr/2½ months**)	X			
.491	.465(c)	Interference Bond Monitoring – Critical (**6 per yr/2½ months**)			X	
.491	.465(c)	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**)			X	
.491	.465(d)	Prompt Remedial Actions	X			
.491	.465(e)	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)	X			
.491	.467	Electrical Isolation (**Including Casings**)	X			
.491	.469	Test Stations – Sufficient Number	X			
.491	.471	Test Leads	X			
.491	.473	Interference Currents	X			
.491	.475(a)	Internal Corrosion; Corrosive Gas Investigation	X			
.491	.475(b)	Internal Corrosion; Internal Surface Inspection; Pipe Replacement				X
.491	.476 (c)	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems	X			
.491	.477	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**)			X	
.491	.481	Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)	X			
.491	.483/.485	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions	X			

Comments:
No interference bonds
No critical interference bonds
No internal inspections conducted
No internal corrosion coupons

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

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192.620	Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
	(ii) Filter separators if needed			X	
	(iii) Gas Monitoring equipment used			X	
	(iv) Cleaning pigs, inhibitors, and sample accumulated liquids				
.620(d)	(v) Limit CO2, H2S, 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	
	(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			X	

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

Comments:
Williams does not use the alternative maximum allowable operating pressure.

Leave this list with the operator.

Recent PHMSA Advisory Bulletins (Last 2 years)

Number	Date	Subject
ADB-07-02	February 29, 2008	Correction - Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-08-01	May 13, 2008	Pipeline Safety - Notice to Operators of Gas Transmission Pipelines on the Regulatory Status of Direct Sales Pipelines
ADB-08-02	March 4, 2008	Pipeline Safety - Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems
ADB-08-03	March 10, 2008	Pipeline Safety - Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems
ADB-08-04	June 5, 2008	Pipeline Safety - Installation of Excess Flow Valves into Gas Service Lines
ADB-08-05	June 25, 2008	Pipeline Safety - Notice to Hazardous Liquid Pipeline Operators of Request for Voluntary Adv Notification of Intent To Transport Biofuels
ADB-08-06	July 2, 2008	Pipeline Safety - Dynamic Riser Inspection, Maintenance, and Monitoring Records on Offshore Floating Facilities
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-10-01	Jan 26, 2010	Pipeline Safety: Leak Detection on Hazardous Liquid Pipelines
ADB-10-02	Feb 3, 2010	Implementation of Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-03	March 24, 2010	Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe

For more PHMSA Advisory Bulletins, go to http://ops.dot.gov/regs/advise.htm