POST INSPECTION MEMORANDUM

RECEIVED
JUN 11 2012
State of Washington
UTC
Pipeline Safety Program

Inspector: Al Jones/WUTC
Reviewed: Joe Subsits/WUTC
Peer Reviewed: RR
Follow-Up Enforcement: ~~No Violation~~
PCP* PCO* NOA (WL) LOC
Director Approval* CH 4/22/12

Noted ak

Date: December 28, 2011

Operator Inspected: **OPID: 15014** **Region:** Western
Gas Transmission Northwest Corporation (GTN)
U.S. Western Pipe Region
1400 SW 5th Ave
Suite 900
Portland, OR 97201

Unit Address:
Rosalia District
201 West North River Drive
Spokane, WA 99201

Unit Inspected: Rosalia District **Unit ID:** 66685
Unit Type: Interstate Natural Gas
Inspection Type: Standard Inspection
Record Location: Spokane, WA
Inspection Dates: November 28 – December 2, 2011
AFOD: Four
SMART Activity Number: 133012 I01 (4 days); 137868 I07 (0.5 day); 137869 I08 (0.5 day) / Sent electronic copy to J. Haddow on 01/27/2012
Operator Contact: Kurt Smith, Pipe Regulatory Specialist
Phone: (509) 533-2831 **Fax:** (509) 546-8825 **Emergency:** (800) 447-8066

Unit Description:
The Rosalia District is located in Eastern Washington in Spokane and Whitman Counties; extending south from the Idaho/Washington border to the Snake River crossing. The pipeline is approximately 100 miles in length. The transmission lines are primarily in Class-1 Location, except the Spokane Valley with about 14 miles of Class-2 Location and about 7 miles of Class-3 Location. The District includes a compressor station at Rosalia, various main line block valves, CP test sites, and rectifier stations.

Facilities Inspected:
The portion of the District inspected include the 36-inch (A-Line) and two 42-inch (B-Line and C-Line) diameter pipelines from the Washington/Idaho border (MP 106.8) to the Spokane Gate Station (MP 108.2). This fall about 3,600 linear feet of the A-line located at Saltese Meadows in Spokane Valley was removed and replaced with a new 36-inch diameter pipeline with FBE coating in a Class-3 Location. The A and B Lines extents south from the Spokane Gate to the Snake River (MP 206.7). The Rosalia Compressor Station contains a Mars Solar (14K Hp), Titan Solar (19.5 Hp), and a LM-1500, GE (12.5 Hp) turbines. Meter Stations located at Spokane, Mica, Spangle, Rosalia, and St. John were inspected for set points, lockup, MAOP, and security. Right-of-way inspection for signage, cathodic protection test sites, casings, and rectifier units. See attached Field Data Report.

Persons Interviewed:

Kurt Smith	Pipe Regulatory Specialist	(509) 533-2832
John Plaster	Area Manager	
James Olson	Rosalia Technician	(509) 533-2831
Patrick Brown	Rosalia Technician	(509) 533-2832
Rich Christman	Corrosion Specialist	(208) 265-2164

Probable Violations/Concerns:
One probable violation for not taking prompt remedial (192.465(d)) action to correct the pipe-to-soil potential with respect to the native potential.
During the annual surveys for 2010 and 2011, the pipe-to-soil "off" potential was less than 100 mV with respect to the native potentials for the following locations:
At MP 110.2 the native potential is -698 mV and 2010 P/S was -669 mV and 2011 P/S was -748 mV, and
At MP 110.8 the native potential is -708 mV and 2010 P/S was -640 mV and 2011 P/S was -792 mV.

Follow up on the history of prior offenses that are still open:

Prior Offenses (for the past 5 years)		
CPF #	**What type of open enforcement action(s)?**	**Status of the regulations(s) violated (Reoccurrence Offenses, Implement a NOA Revision, Completion of PCO or CO, and etc...)**

Recommendations:
Maintain normal inspection cycle and warning letter be submitted for the one probable violation. Also recommend that a follow up inspection be conducted to confirm that the probable violation has been corrected.

Comments:
The B-Line casing potential at MP 112 has a greater potential than the pipe-to-soil potential. Additional evaluation is required to identify if anodes are attached to the casing. The casing is located at an abandoned railroad track and is adjacent to a new housing development. Rich Christman, Corrosion Specialist, is new to the District and has been working on evaluating the casing. The operator has provided additional documentation following this field inspection that states the casing was evaluated in 2009 and concluded that casing is not shorted to the carrier pipe because the casing values did not shift during the ON/OFF survey. The B-Line is not piggable because of reduced pipe size at the Snake River crossing. Future inspection need to monitored casing data and encourage the Operator to remove the casing.

Attachments:
PHMSA Form 1 - Standard Procedures/Standard Inspection
PHMSA Form 13 - Pipeline Drug &Alcohol Questions
PHMSA Form 15 - OQ Field Inspection Protocol
PHMSA Form 16 - Gas IMP Field Verification Inspection
PHMSA Form 17 - Supplemental SCC Questionnaire Gas Transmission or Liquid Pipeline
Form W - Public Awareness Program Field Audit 1162
Western Region Unit Information Form
Field Data Collection Form
WUTC Data Request #2 – Reply from GTN
Violation report

Version Date: 5/5/08

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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:	Al Jones / December 22, 2011	**Inspector/Submit Date:**	Al Jones / 12-22-2011
		Peer Review/Date:	Joe Subsits / 12-22-2011
		Director Approval/Date:	CH 4/22/12

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	TransCanada Gas Transmission Northwest Corporation (GTN)	**OPID #:**	15014
Name of Unit(s):	Rosalia District	**Unit #(s):**	66685
Records Location:	Spokane, WA	**Activity #**	
Unit Type & Commodity:	Interstate Natural Gas		
Inspection Type:	Standard Pipeline & Compressor Station	**Inspection Date(s):**	Nov. 28 – Dec. 1, 2011
PHMSA Representative(s):	Al Jones / UTC	**AFO Days:**	5

Company System Maps (copies for Region Files):	At District Office and employees' field computers.
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:

The Rosalia District is predominately located in wheat fields and open land except for the Spokane Valley where development has encroached on the ROW. A new section about 3,600 linear feet of the A-Line was replaced with greater wall thickness (0.500") and SMYS API 5L X70) than the original pipeline at a Class-3 Location.

Findings:

NOPV: 192.465(d) Prompt Remedial Action

During the annual surveys for 2010 and 2011, the pipe-to-soil "off" potential difference was less than 100 mV with respect to the native potential. At MP 110.2 the native potential is -0.698V and P/S for 2010 was -0.669V and for 2011 was -0.748V. At MP 110.8 the native potential is -0.708V and P/S for 2010 was -0.640V and for 2011 was -0.792V.

Future inspection need to monitor the casing electrical isolation at MP 112:

The B-Line casing potential at MP 112 has a greater potential than the pipe-to-soil potential. Additional evaluation is required to identify if anodes are attached to the casing. The casing is located at an abandoned railroad track and is adjacent to a new housing development. Rich Christman, Corrosion Specialist, is new to the District and has been working on evaluating the casing. The operator has provided additional documentation following this field inspection that states the casing was evaluated in 2009 and concluded that casing is not shorted to the carrier pipe because the casing values did not shift during the ON/OFF survey. The B-Line is not piggable because of reduced pipe size at the Snake River crossing.

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

Name of Operator:	TransCanada, Gas Transmission Northwest Corporation		
OP ID No. [1]		**Unit ID No.** [1]	
HQ Address:		**System/Unit Name & Address:** [1]	
201 West North River Drive Spokane, WA 99201		201 West North River Drive Spokane, WA 99201	
Co. Official:	Ken Leier, Regional Director	**Activity Record ID No.:**	PG-110390
Phone No.:	509-533-2831	**Phone No.:**	509-546-8865
Fax No.:	509-533-2825	**Fax No.:**	509-546-8825
Emergency Phone No.:	800-447-8066	**Emergency Phone No.:**	800-447-8066

Persons Interviewed	Title	Phone No.
Kurt Smith	Compliance Specialist, GTN Systems	509-546-8865
Rich Christman	Corrosion Specialist (NACE II)	208-265-2164

PHMSA Representative(s) [1]	Al Jones / UTC	**Inspection Date(s)** [1]	Nov 28 – Dec 2, '11
Company System Maps (Copies for Region Files):	Spokane, WA		

Unit Description:
The Rosalia District is located in Eastern Washington in Spokane and Whitman Counties; extending south from the Idaho/Washington border to the Snake River crossing. The pipeline is approximately 100 miles in length. The transmission lines are primarily in Class-1 Location, except the Spokane Valley with about 13 miles of Ecological HCA and about 8 miles of population HCA Class-3 Location. The District includes a compressor station at Rosalia, main line block valves, CP test sites, and rectifier stations.

Portion of Unit Inspected: [1]
The portion of the District inspected include the 36-inch (A-Line) and two 42-inch (B-Line and C-Line) diameter pipelines from the Washington/Idaho border (MP 106.8) to the Spokane Gate Station (MP 108.2). A portion of the A-Line (3,000 linear feet) was replaced at Saltese Meadows in Spokane Valley with a new 36-inch diameter, .500-inch wall thickness, and coated with FBE material. The new pipe section is a Class-3 Location. The A and B Lines extents south from the Spokane Gate to the Snake River (MP 206.7). The Rosalia Compressor Station contains a Mars Solar (14K Hp), Titan Solar (19.5 Hp), and a LM-1500, GE (12.5 Hp) turbines. Meter Stations inspected included Spokane, St. John, and LaCrosse for set points, lockup, MAOP, and security. Right-of-way inspection for signage, cathodic protection test sites, casings, and rectifier units. See attached Field Data Report.

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 03/16/06 and 03/17/2011.

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

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	NPMS INFORMATION and UPDATE	Yes	No
	Did the operator submit their pipeline information to NPMS and did they submit any updates or changes? 49 U.S.C. 60132 and ADB-08-07	x	

49 CFR PART 191

	REPORTING PROCEDURES	S	U	N/A	N/C
.605(b)(4)	Procedures for gathering data for incident reporting				
*	191.5 Immediate Notice of certain incidents to **NRC (800) 424-8802,** or electronically at http://www.nrc.uscg.mil/nrchp.html, and additional report if significant new information becomes available. Operator must have a written procedure for calculating an initial estimate of the amount of product released in an accident. (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	X			
*	191.7 Reports (except SRCR and offshore pipeline condition reports) must be submitted electronically to PHMSA at https://opsweb.phmsa.dot.gov unless an alternative reporting method is authorized IAW with paragraph (d) of this section. (Amdt. 191-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	X			
*	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).	X			
	191.15(c) Supplemental report (to 30-day follow-up)	X			
.605(a)	191.17 Complete and submit DOT Form PHMSA F 7100-2.1 by March 15 of each calendar year for the preceding year. *(NOTE: June 15, 2011 for the year 2010).* (Amdt. 192-115, 75 FR 72878, November 26, 2010).	X			
*	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).	X			
	191.23 Reporting safety-related condition (SRCR)	X			
	191.25 Filing the SRCR within 5 days of determination, but not later than 10 days after discovery	X			
	191.27 Offshore pipeline condition reports – filed within 60 days after the inspections	X			
.605(d)	Instructions to enable operation and maintenance personnel to recognize potential **Safety Related Conditions**	X			

Comments:

49 CFR PART 192

.13(c)	CUSTOMER NOTIFICATION PROCEDURES	S	U	N/A	N/C
	.16 Procedures for notifying new customers, within **90 days**, of their responsibility for those selections of service lines not maintained by the operator.			X	

.14	CONVERSION OF SERVICE PROCEDURES	S	U	N/A	N/C
	A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:				
	.14(a)(1) Review of the design, construction operation and maintenance history.			X	
	.14(a)(2) Visual Right-of-way and pipeline inspection for physical defects and operating conditions.			X	
	.14(a)(3) Correction of known unsafe defects and conditions.			X	
	.14(a)(4) Pipeline tested in accordance with Subpart J.			X	

.605(a)	NORMAL OPERATING and MAINTENANCE PROCEDURES	S	U	N/A	N/C
	.605(a) O&M Plan review and update procedure (**1 per year/15 months**)	X			

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	.605(b)(3)	Making construction records, maps, and operating history available to appropriate operating personnel	X			
	.605(b)(5)	Start up and shut down of the pipeline to assure operation within **MAOP** plus allowable buildup	X			
	.605(b)(8)	Periodically reviewing the work done by operator's personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found	X			
	.605(b)(9)	Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapors or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and a rescue harness and line	X			
	.605(b)(10)	Routine inspection and testing of pipe-type or bottle-type holders			X	
	.605(b)(11)	Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedure under §192.615(a)(3) specifically apply to these reports.	X			
*	.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).	X			

Comments:

No pipelines were converted to natural gas use.
.605(b)(9) Excavated trench information is contained in TOP 003672343.
Bottle-type holders are not used.

.605(a)	ABNORMAL OPERATING PROCEDURES		S	U	N/A	N/C
	.605(c)(1)	Procedures for responding to, investigating, and correcting the cause of:				
		(i) Unintended closure of valves or shut downs	X			
		(ii) Increase or decrease in pressure or flow rate outside of normal operating limits	X			
		(iii) Loss of communications	X			
		(iv) The operation of any safety device	X			
		(v) Malfunction of a component, deviation from normal operations or personnel error	X			
	.605(c)(2)	Checking variations from normal operation after abnormal operations ended at sufficient critical locations	X			
	.605(c)(3)	Notifying the responsible operating personnel when notice of an abnormal operation is received	X			
	.605(c)(4)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found	X			

Comments:

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

Comments:

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.613	CONTINUING SURVEILLANCE PROCEDURES		S	U	N/A	N/C
	.613(a)	Procedures for surveillance and required actions relating to change in class location, failures, leakage history, corrosion, substantial changes in **CP** requirements, and unusual operating and maintenance conditions	X			
	.613(b)	Procedures requiring **MAOP** to be reduced, or other actions to be taken, if a segment of pipeline is in unsatisfactory condition	X			

Comments:
Surveillance Procedures are contained in TOP 003841208

.605(a)	DAMAGE PREVENTION PROGRAM PROCEDURES		S	U	N/A	N/C
	.614	Participation in a qualified one-call program, or if available, a company program that complies with the following:				
		(1) Identify persons who engage in excavating	X			
		(2) Provide notification to the public in the One Call area	X			
		(3) Provide means for receiving and recording notifications of pending excavations	X			
		(4) Provide notification of pending excavations to the members	X			
		(5) Provide means of temporary marking for the pipeline in the vicinity of the excavations	X			
		(6) Provides for follow-up inspection of the pipeline where there is reason to believe the pipeline could be damaged	X			
		(i) Inspection must be done to verify integrity of the pipeline	X			
		(ii) After blasting, a leak survey must be conducted as part of the inspection by the operator	X			

Comments:

.615	EMERGENCY PROCEDURES		S	U	N/A	N/C
	.615(a)(1)	Receiving, identifying, and classifying notices of events which require immediate response by the operator	X			
	.615(a)(2)	Establish and maintain communication with appropriate public officials regarding possible emergency	X			
	.615(a)(3)	Prompt response to each of the following emergencies:				
		(i) Gas detected inside a building	X			
		(ii) Fire located near a pipeline	X			
		(iii) Explosion near a pipeline	X			
		(iv) Natural disaster	X			
	.615(a)(4)	Availability of personnel, equipment, instruments, tools, and material required at the scene of an emergency	X			
	.615(a)(5)	Actions directed towards protecting people first, then property	X			
	.615(a)(6)	Emergency shutdown or pressure reduction to minimize hazards to life or property	X			
	.615(a)(7)	Making safe any actual or potential hazard to life or property	X			

	.615(a)(8)	Notifying appropriate public officials required at the emergency scene and coordinating planned and actual responses with these officials	X			
	.615(a)(9)	Instructions for restoring service outages after the emergency has been rendered safe	X			
	.615(a)(10)	Investigating accidents and failures as soon as possible after the emergency	X			
*	.615(a)(11)	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).	X			
	.615(b)(1)	Furnishing applicable portions of the emergency plan to supervisory personnel who are responsible for emergency action	X			
	.615(b)(2)	Training appropriate employees as to the requirements of the emergency plan and verifying effectiveness of training	X			
	.615(b)(3)	Reviewing activities following emergencies to determine if the procedures were effective	X			
	.615(c)	Establish and maintain liaison with appropriate public officials, such that both the operator and public officials are aware of each other's resources and capabilities in dealing with gas emergencies	X			

Comments:

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.					
	.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:

.617	FAILURE INVESTIGATION PROCEDURES	S	U	N/A	N/C

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.617	FAILURE INVESTIGATION PROCEDURES		S	U	N/A	N/C
	.617	Analyzing accidents and failures including laboratory analysis where appropriate to determine cause and prevention of recurrence	X			

Comments:

.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)(2) Test pressure divided by applicable factor	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			
		(a)(4) Maximum safe pressure determined by operator.	X			
		(b) Overpressure protective devices must be installed if .619(a)(4) is applicable	X			
*		(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- 107, 73 FR 62147, October 17, 2008, eff. 11/17/2008).				

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.

Comments:

.13(c)	PRESSURE TEST PROCEDURES	S	U	N/A	N/C
	.503 Pressure testing	X			

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Comments:

.13(c)	UPRATING PROCEDURES	S	U	N/A	N/C
	.553 Uprating	X			

Comments:

.605(a)	ODORIZATION of GAS PROCEDURES		S	U	N/A	N/C
	.625(b)	Odorized gas in **Class 3** or **4** locations (if applicable) – must be readily detectable by person with normal sense of smell at $^{1}/_{5}$ of the LEL			X	
	.625(f)	Periodic gas sampling, using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.			X	

Comments:
Interstate pipeline gas is not odorized.

.605(a)	TAPPING PIPELINES UNDER PRESSURE PROCEDURES		S	U	N/A	N/C
	.627	Hot taps must be made by a qualified crew **NDT** testing is suggested prior to tapping the pipe. Reference API RP 2201 for **Best Practices.**	X			

.605(a)	PIPELINE PURGING PROCEDURES		S	U	N/A	N/C
	.629	Purging of pipelines must be done to prevent entrapment of an explosive mixture in the pipeline				
		(a) Lines containing air must be properly purged.	X			
		(b) Lines containing gas must be properly purged	X			

Comments:

*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
.605(a)	.631(a)	(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, except where an operator's activities are limited to: (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.				

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*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
	.631(a)	.605(b)(12) Each operator must have and follow written control room management procedures. NOTE: *An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than February 1, 2013.*				
	.631(b)	The operator's program must define the roles and responsibilities of a controller during normal, abnormal and emergency conditions including a definition of:				
		(1) Controller's authority and responsibility.				X
		(2) Controller's role when an abnormal operating condition is detected.				X
		(3) Controller's role during an emergency				X
		(4) A method of recording shift change responsibilities between controllers.				X
	.631(c)	The operator's program must provide its controllers with the information, tools, processes and procedures necessary to perform each of the following:				
		(1) Implement sections 1, 4, 8,9,11.2, and 11.3 of API RP 1165 whenever a SCADA System is added, expanded or replaced.				X
		(2) Conduct point-to-point verification between SCADA displays and related equipment when changes that affect pipeline safety are made.				X
		(3) Test and verify any internal communications plan – at least once a year NTE 15 months.				X
		(4) Test any backup SCADA system at least once each year but NTE 15 months.				X
		(5) Establish and implement procedures for when a different controller assumes responsibility.				X
	.631(d)	Each operator must implement and follow methods to reduce the risk associated with controller fatigue, including:				
		(1) Establishing shift lengths and schedule rotations that provide time sufficient to achieve eight hours of continuous sleep.				X
		(2) Educating controllers and supervisors in fatigue mitigation strategies.				X
		(3) Training of controllers and supervisors to recognize the effects of fatigue.				X
		(4) Establishing a maximum limit on controller hours-of-service.				X
	.631(e)	Each operator must have a written alarm management plan including these provisions:				
		(1) Reviewing alarms using a process that ensures that they are accurate and support safe operations.				X
		(2) Identifying at least once a year, points that have been taken off SCADA scan or have had alarms inhibited, generated false alarms, or have had forced or manual values for periods of time exceeding that required for maintenance activities.				X
		(3) Verifying the alarm set-point values and alarm descriptions once each year NTE 15 months.				X
		(4) Reviewing the alarm management plan at least once every calendar year NTE 15 months.				X
		(5) Monitoring the content and volume of activity being directed to and required of each controller once each year NTE 15 months.				X
		(6) Addressing deficiencies identified through implementation of 1-5 of this section.				X
	.631(f)	Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing the following:				
		(1) Establishing communications between controllers, management and field personnel when implementing physical changes to the pipeline.				X
		(2) Requiring field personnel to contact the control room when emergency conditions exist and when field changes could affect control room operations.				X
		(3) Seeking control room or management participation in planning prior to implementation of significant pipeline changes.				X
	.631(g)	Each operator must assure that lessons learned from its experience are incorporated in to its procedures by performing the following:				
		(1) Reviewing reportable incidents to determine if control room actions contributed to the event and correcting any deficiencies.				X

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
		(2) Including lessons learned from the operator's training program required by this section.				X
	.631(h)	Each operator must establish a controller training program and review its contents once a year NTE 15 months which includes the following elements:				X
		(1) Responding to abnormal operating conditions (AOCs).				X
		(2) Using a computerized simulator or other method for training controllers to recognize AOCs				X
		(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures.				X
		(4) Training that provides a working knowledge of the pipeline system, especially during AOCs.				X
		(5) Providing an opportunity for controllers to review relevant procedures for infrequently used operating setups.				X

Comments:
Per PHMSA Western Region – Mark CRM items as N/C. Headquarters CRM inspection to be scheduled at a future date.

.605(a)		MAINTENANCE PROCEDURES	S	U	N/A	N/C
	.703(b)	Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service	X			
	(c)	Hazardous leaks must be repaired promptly	X			

Comments:

.605(b)		TRANSMISSION LINES - PATROLLING & LEAKAGE SURVEY PROCEDURES	S	U	N/A	N/C
	.705(a)	Patrolling ROW conditions	X			
	(b)	Maximum interval between patrols of lines:	X			
	.706	Leakage surveys – **1 year/15 months**	X			
		Leak **detector equipment** survey requirements for lines transporting un-odorized gas				
		(a) **Class 3** locations - **7½ months** but at least **twice each calendar year**	X			
		(b) **Class 4** locations - **4½ months** but at least **4 times each calendar year**	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)

Comments:

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Comments:

.605(b)	LINE MARKER PROCEDURES		S	U	N/A	N/C
	.707	Line markers installed and labeled as required	X			

Comments:

.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			
		(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:

.605(b)	FIELD REPAIR PROCEDURES		S	U	N/A	N/C
		Imperfections and Damages				
	.713(a)	Repairs of imperfections and damages on pipelines operating above **40% SMYS**				
		(1) Cut out a cylindrical piece of pipe and replace with pipe of ≥ design strength	X			
		(2) Use of a reliable engineering method	X			
	.713(b)	Reduce operating pressure to a safe level during the repair	X			
		Permanent Field Repair of Welds				
	.715	Welds found to be unacceptable under §192.241(c) must be repaired by:				
		(a) If feasible, taking the line out of service and repairing the weld in accordance with the applicable requirements of **§192.245.**	X			
		(b) If the line remains in service, the weld may be repaired in accordance with **§192.245** if:				
		(1) The weld is not leaking	X			
		(2) The pressure is reduced to produce a stress that is **20% of SMYS or less**	X			
		(3) Grinding is limited so that **⅛ inch** of pipe weld remains	X			
		(c) If the weld cannot be repaired in accordance with **(a) or (b)** above, a full encirclement welded split sleeve must be installed	X			
		Permanent Field Repairs of Leaks				
	.717	Field repairs of leaks must be made as follows:				
		(a) Replace by cutting out a cylinder and replace with pipe similar or of greater design	X			
		(b)(1) Install a full encirclement welded split sleeve of an appropriate design unless the pipe is **joined by mechanical couplings** and **operates at less than 40% SMYS**	X			
		(b)(2) A leak due to a corrosion pit may be repaired by installing **a bolt on leak clamp**	X			

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.605(b)	FIELD REPAIR PROCEDURES		S	U	N/A	N/C
	(b)(3)	For a corrosion pit leak, if a pipe is not more than **40,000 psi SMYS**, the pits may be repaired by **fillet welding a steel plate**. The plate must have **rounded corners** and the same **thickness or greater** than the pipe, and **not more than ½D** of the pipe size	X			
	(b)(4)	Submerged offshore pipe or pipe in inland navigable waterways may be repaired with a mechanically applied full encirclement split sleeve of appropriate design	X			
	(b)(5)	Apply reliable engineering method	X			
		Testing of Repairs				
	.719(a)	Replacement pipe must be pressure tested to meet the requirements of a new pipeline	X			
	(b)	For lines of **6-inch diameter or larger** and that **operate at 20% of more of SMYS,** the repair must be nondestructively tested in accordance with **§192.241(c)**	X			

Comments:

.605(b)	ABANDONMENT or DEACTIVATION of FACILITIES PROCEDURES		S	U	N/A	N/C
	.727(b)	Operator must disconnect both ends, purge, and seal each end before abandonment or a period of deactivation where the pipeline is not being maintained. Offshore abandoned pipelines must be filled with water or an inert material, with the ends sealed	X			
	(c)	Except for service lines, each inactive pipeline that is not being maintained under Part 192 must be disconnected from all gas sources/supplies, purged, and sealed at each end.	X			
	(d)	Whenever service to a customer is discontinued, do the procedures indicate one of the following:				
		(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator	X			
		(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly	X			
		(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed	X			
	(e)	If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging	X			
*	.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:

.605(b)	COMPRESSOR STATION PROCEDURES		S	U	N/A	N/C
	.605(b)(6)	Maintenance procedures, including provisions for isolating units or sections of pipe and for purging before returning to service	X			
	.605(b)(7)	Starting, operating, and shutdown procedures for gas compressor units	X			
	.731	Inspection and testing procedures for remote control shutdowns and pressure relieving devices (**1 per yr/15 months**), prompt repair or replacement	X			

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	.735	(a) Storage of excess flammable or combustible materials at a safe distance from the compressor buildings	X			
*		(b) Tank must be protected according to **NFPA #30;** Amdt 192-103 pub. 06/09/06 eff. 07/10/06.	X			
	.736	Compressor buildings in a compressor station must have fixed gas detection and alarm systems (**must be performance tested**), unless:	X			
		▪ **50% of the upright side areas** are permanently open, or	X			
		▪ It is an unattended field compressor station of **1000 hp or less**	X			

Comments:

.605(b)	PRESSURE LIMITING and REGULATING STATION PROCEDURES		S	U	N/A	N/C
	.739(a)	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (**1 per yr/15 months**)	X			
		(1) In good mechanical condition	X			
		(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed	X			
	.739(a)	(3) Set to control or relieve at correct pressures consistent with .201(a), except for .739(b).	X			
		(4) Properly installed and protected from dirt, liquids, other conditions that may prevent proper oper.	X			
	.739(b)	For steel lines if MAOP is determined per .619(c) and the MAOP is 60 psi (414 kPa) gage or more . . .				
		If MAOP produces hoop stress that: Is greater than 72 percent of SMYS → Then the pressure limit is: MAOP plus 4 percent; Is unknown as a percent of SMYS → A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP	X			
	.743	Testing of Relief Devices				
	.743	(a) Capacity must be consistent with .201(a) except for .739(b), and be determined **1 per yr/15 mo.**	X			
	.743	(b) If calculated, capacities must be compared; annual review and documentation are required.	X			
	.743	(c) If insufficient capacity, new or additional devices must be installed to provide required capacity.	X			

Comments:

.605(b)	VALVE MAINTENANCE PROCEDURES		S	U	N/A	N/C
	.745	(a) Inspect and partially operate each transmission valve that might be required during an emergency (**1 per yr/15 months**)	X			
	.745	(b) Prompt remedial action required, or designate alternative valve.	X			

.605(b)	VAULT INSPECTION PROCEDURES		S	U	N/A	N/C
	.749	Inspection of vaults greater than **200 cubic feet** and housing pressure regulating or limiting devices (**1 per yr NTE 15 months**).				

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Comments:
There are not vaults in the district > 200CF.

.605(b)	PREVENTION of ACCIDENTAL IGNITION PROCEDURES		S	U	N/A	N/C
	.751	Reduce the hazard of fire or explosion by:				
		(a) Removal of ignition sources in presence of gas and providing for a fire extinguisher	X			
		(b) Prevent welding or cutting on a pipeline containing a combustible mixture	X			
		(c) Post warning signs	X			

Comments:

.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			
		(b) Retention of welding procedure – details and test	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 (20th edition 2007, including errata 2008)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2007 edition, July 1, 2007)**, except that a welder qualified under an earlier edition than currently listed in **192.7** may weld, but may not requalify under that earlier edition. (Amdt 192-114 Pub. 8/11/10 eff. 10/01/10).	X			
		(b) Welders may be qualified under **section I of Appendix C** to weld on lines that operate at **< 20% SMYS.**	X			
	.229	(a) To weld on compressor station piping and components, a welder must successfully complete a destructive test	X			
		(b) Welder must have used welding process within the preceding **6 months**	X			
		(c) A welder qualified under .227(a) –				
	.229(c)	(1) May not weld on pipe that operates at ≥ 20% SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the **sections 6 or 9 of API Standard 1104**; may maintain an ongoing qualification status by performing welds tested and found acceptable at least **twice per year**, not exceeding **7½ months**; may not requalify under an earlier referenced edition.	X			
		(2) May not weld on pipe that operates at < 20% SMYS unless is tested in accordance with .229(c)(1) or requalifies under .229(d)(1) or (d)(2).	X			
		(d) Welders qualified under .227(b) may not weld unless:				
		(1) Requalified within **1 year/15 months**, or	X			
		(2) Within **7½ months** but at least **twice per year** had a production weld pass a qualifying test	X			
	.231	Welding operation must be protected from weather	X			
	.233	Miter joints (**consider pipe alignment**)	X			
	.235	Welding preparation and joint alignment **Alert Notice 3/24/10**: Do operator's procedures give consideration to girth weld bevels being properly transitioned and aligned, girth weld pipe ends meeting API 5L pipe end diameter and diameter out-of-roundness specifications, and API 1104 alignment and allowable ``high-low" criteria, particularly in large diameter pipe (> 20" diameter)?	X			
	.241	(a) Visual inspection must be conducted by an individual qualified by appropriate training and experience to ensure:	X			
		(1) Compliance with the welding procedure	X			

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.13(c)	WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A	N/C
	(2) Weld is acceptable in accordance with **Section 9 of API 1104**	X			
	(b) Welds on pipelines to be **operated at 20% or more of SMYS** must be nondestructively tested in accordance with **192.243** except welds that are visually inspected and approved by a qualified welding inspector if:	X			
	(1) The nominal pipe diameter is less than **6 inches**, or	X			
	(2) The pipeline is to operate at a pressure that produces a hoop stress of less than **40% of SMYS** and the welds are so limited in number that nondestructive testing is impractical	X			
	.241 (c) Acceptability based on visual inspection or NDT is determined according to **Section 9 of API 1104.** If a girth weld is unacceptable under **Section 9** for a reason other than a crack, and if **Appendix A to API 1104** applies to the weld, the acceptability of the weld may be further determined under that appendix.	X			
	Note: If the alternative acceptance criteria in API 1104 Appendix A are used, has the operator performed an Engineering Critical Assessment (ECA)?				
	.245 Repair and Removal of Weld Defects				
	(a) Each weld that is unacceptable must be removed or repaired. Except for offshore pipelines, a weld must be removed if it has a crack that is more than **8%** of the weld length	X			
	(b) Each weld that is repaired must have the defect removed down to sound metal, and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the weld must be inspected and found acceptable.	X			
	(c) Repair of a crack or any other defect in a previously repaired area must be in accordance with a written weld repair procedure, qualified under **§192.225**	X			
	Note: Sleeve Repairs – use low hydrogen rod (**Best Practices –ref. API 1104 App. B, In Service Welding**)				

Comments:

.13(c)	NONDESTRUCTIVE TESTING PROCEDURES	S	U	N/A	N/C
	.243 (a) Nondestructive testing of welds must be performed by any process, other than trepanning, that clearly indicates defects that may affect the integrity of the weld	X			
	(b) Nondestructive testing of welds must be performed:				
	(1) In accordance with a written procedure, and	X			
	(2) By persons trained and qualified in the established procedures and with the test equipment used	X			
	(c) Procedures established for proper interpretation of each nondestructive test of a weld to ensure acceptability of the weld under **192.241(c)**	X			
	(d) When nondestructive testing is required under **§192.241(b)**, the following percentage of each day's field butt welds, selected at random by the operator, must be nondestructively tested over the entire circumference				
	(1) In **Class 1** locations at least **10%**	X			
	(2) In **Class 2** locations at least **15%**	X			
	(3) In **Class 3** and **4** locations, at crossings of a major navigable river, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, **100%** unless impractical, then **90%**. Nondestructive testing must be impractical for each girth weld not tested.	X			
	(4) At pipeline tie-ins, **100%**	X			
	(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under **§192.241(b)**	X			

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.13(c)	NONDESTRUCTIVE TESTING PROCEDURES	S	U	N/A	N/C
	(f) Nondestructive testing – the operator must retain, for the life of the pipeline, a record showing by mile post, engineering station, or by geographic feature, the number of welds nondestructively tested, the number of welds rejected, and the disposition of the rejected welds.	X			

Comments:

.273(b)		JOINING of PIPELINE MATERIALS	S	U	N/A	N/C
	.281	Joining of plastic pipe				
		• Type of plastic used			X	
		• Proper markings in accordance with **§192.63**			X	
		• Manufacturer			X	
		• Type of joint used			X	
*	.283	Qualified joining procedures for plastic pipe must be in place. Amdt. 192-103 pub. 06/09/06, eff. 07/10/06.			X	
	.285	Persons making joints with plastic pipe must be qualified			X	
	.287	Persons inspecting plastic joints must be qualified			X	

Comments:
The District does not have plastic pipe.

.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.453	Are corrosion procedures established and carried out by or under the direction of a qualified person for:				
		• Design	X			
		• Operations	X			
		• Installation	X			
		• Maintenance	X			
	.455	(a) For pipelines installed **after July 31, 1971**, buried segments must be externally coated and (b) cathodically protected within **one year** after construction (see exceptions in code)	X			
		(c) Aluminum may not be installed in a buried or submerged pipeline if exposed to an environment with a natural **pH in excess of 8** (see exceptions in code)	X			
	.457	(a) All effectively coated steel transmission pipelines installed prior to **August 1, 1971**, must be cathodically protected	X			
		(b) If installed **before August 1, 1971**, cathodic protection must be provided in areas of active corrosion for: bare or ineffectively coated transmission lines, and bare or coated c/s, regulator sta, and meter sta. piping.	X			
	.459	Examination of buried pipeline when exposed: if corrosion is found, further investigation is required	X			
	.461	Procedures must address the protective coating requirements of the regulations. External coating on the steel pipe must meet the requirements of this part.	X			
	.463	Cathodic protection level according to **Appendix D** criteria	X			
	.465	(a) Pipe-to-soil monitoring (**1 per yr/15 months**) or short sections (**10% per year, all in 10 years**)	X			
		(b) Rectifier monitoring (**6 per yr/2½ months**)	X			

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.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		(c) Interference bond monitoring (**as required**)	X			
		(d) Prompt remedial action to correct any deficiencies indicated by the monitoring	X			
	.465	(e) Electrical surveys (closely spaced pipe to soil) on bare/unprotected lines, cathodically protect active corrosion areas (**1 per 3 years/39 months**).	X			
	.467	Electrical isolation (**include casings**)	X			
	.469	Sufficient test stations to determine CP adequacy	X			
	.471	Test leads	X			
	.473	Interference currents	X			
	.475	(a) Proper procedures for transporting corrosive gas?	X			
*		(b) Removed pipe must be inspected for internal corrosion. If found, the adjacent pipe must be inspected to determine extent. Certain pipe must be replaced. Steps must be taken to minimize internal corrosion.	X			
*	.476	Systems designed to reduce internal corrosion Final Rule Pub. (a) New construction Final Rule Pub. 4/23/07, eff. 5/23/07.	X			
*		(b) Exceptions – offshore pipeline and systems replaced before 5/23/07. Final Rule Pub. 4/23/07, eff. 5/23/07.	X			
		(c) Evaluate impact of configuration changes to existing systems. Final Rule Pub. 4/23/07, eff. 5/23/07.	X			
	.477	Internal corrosion control coupon (or other suit. Means) monitoring (**2 per yr/7½ months**)			X	
	.479	(a) Each exposed pipe must be cleaned and coated (see exceptions under .479(c))	X			
		Offshore splash zones and soil-to-air interfaces must be coated	X			
		(b) Coating material must be suitable	X			
		Coating is not required where operator has proven that corrosion will:				
		(c) (1) Only be a light surface oxide, or	X			
		(2) Not affect safe operation before next scheduled inspection	X			
	.481	(a) Atmospheric corrosion control monitoring (**1 per 3 yrs/39 months onshore; 1 per yr/15 months offshore**)	X			
	.481	(b) Special attention required at soil/air interfaces, thermal insulation, under disbonded coating, pipe supports, splash zones, deck penetrations, spans over water.	X			
	.481	(c) Protection must be provided if atmospheric corrosion is found (**per §192.479**).	X			
	.483	Replacement pipe must be coated and cathodically protected (see code for exceptions)	X			
	.485	(a) Procedures to replace pipe or reduce the **MAOP** if general corrosion has reduced the wall thickness?	X			
		(b) Procedures to replace/repair pipe or reduce **MAOP** if localized corrosion has reduced wall thickness (unless reliable engineering repair method exists)?	X			
		(c) Procedures to use **Rstreng** or **B-31G** to determine remaining wall strength?	X			
	.491	Corrosion control maps and record retention (**pipeline service life or 5 yrs**)	X			

Comments:
0.447 Internal corrosion coupons are not used within the District. At the Canadian/Idaho border the gas is analyzed by gas chromatograph for moisture content and at Compressor Station #4 scrubber. Liquids are monitored once per year at scrubber separator near Kings Gate (Station #3) located in British Columbia, Canada and at Ione, Oregon at GTN's inter-tie with Williams Pipeline.

.605(b)		UNDERWATER INSPECTION PROCEDURES – GULF of MEXICO and INLETS If the operator has no pipelines in the Gulf, check here and skip this section ___	S	U	N/A	N/C
	.612(a)	Operator must have a procedure prepared by August 10, 2005 to identify pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep that are at risk of being an exposed underwater pipeline or a hazard to navigation?			X	
	.612(b)	Operator must conduct appropriate periodic underwater inspections based on the identified risk			X	

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.605(b)	UNDERWATER INSPECTION PROCEDURES – GULF of MEXICO and INLETS If the operator has no pipelines in the Gulf, check here and skip this section ___	S	U	N/A	N/C
	.612(c) Do procedures require the operator to take action when the operator discovers that a pipeline is exposed on the seabed, or constitutes a hazard to navigation:			X	
	(1) Promptly, within **24 hours**, notify the **National Response Center** of the location of the pipeline?			X	
	(2) Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at the ends of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline **segment less than 200 yards long** need only be marked at the center?			X	
	(3) Place the pipeline so that the top of the pipe is **36 inches below the seabed for normal excavation** or **18 inches for rock excavation** within **6 months** of discovery or not later than **November 1** of the following year if the **6 month period** is later than **November 1** of the year the discovery is made? See code re: engineering alternatives, PHMSA notification.			X	

.801-.809	Subpart N — Qualification of Pipeline Personnel Procedures
	Operator Qualification Inspection – Use PHMSA Form # 15 as applicable

.901-.951	Subpart O — Pipeline Integrity Management
	This form does not cover Gas Pipeline Integrity Management Programs

Subparts A - C	PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES
	Drug & Alcohol Testing & Alcohol Misuse Prevention Program – Use PHMSA Form # 13, PHMSA Drug and Alcohol Program Check.

Comments:

	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			
.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(c)	Warning Signs Posted	X			

Comments:

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

Unless otherwise noted, all code references are to 49CFR Part 192. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) ____	S	U	N/A	N/C
.163(c)	Main operating floor must have (at least) two (2) separate and unobstructed exits	X			
	Door latch must open from inside without a key	X			
	Doors must swing outward	X			
.163(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			
.163(e)	Does the equipment and wiring within compressor stations conform to the **National Electric Code, ANSI/NFPA 70?**	X			
.165(a)	If applicable, are there liquid separator(s) on the intake to the compressors?	X			
.165(b)	Do the liquid separators have a manual means of removing liquids?	X			
	If slugs of liquid could be carried into the compressors, are there automatic dumps on the separators, Automatic compressor shutdown devices, or high liquid level alarms?			X	
.167(a)	ESD system must:				
	- Discharge blowdown gas to a safe location	X			
	- Block and blowdown the gas in the station	X			
	- Shut down gas compressing equipment, gas fires, electrical facilities in compressor building and near gas headers	X			
	- Maintain necessary electrical circuits for emergency lighting and circuits needed to protect equipment from damage	X			
	ESD system must be operable from at least two locations, each of which is:				
	- Outside the gas area of the station	X			
	- Not more than 500 feet from the limits of the station	X			
	- ESD switches near emergency exits?	X			
.167 (b)	For stations supplying gas directly to distribution systems, is the ESD system configured so that the LDC will not be shut down if the ESD is activated?			X	
.167(c)	Are ESDs on platforms designed to actuate automatically by…				
	- For unattended compressor stations, when:				
	▪ The gas pressure equals MAOP plus 15%?	X			
	▪ An uncontrolled fire occurs on the platform?	X			
	- For compressor station in a building, when				
	▪ An uncontrolled fire occurs in the building?	X			
	▪ Gas in air reaches 50% or more of LEL in a building with a source of ignition (facility conforming to **NEC Class 1, Group D** is not a source of ignition)?	X			
.171(a)	Does the compressor station have adequate fire protection facilities? If fire pumps are used, they must not be affected by the ESD system.	X			
(b)	Do the compressor station prime movers (other than electrical movers) have over-speed shutdown?	X			
(c)	Do the compressor units alarm or shutdown in the event of inadequate cooling or lubrication of the unit(s)?	X			
(d)	Are the gas compressor units equipped to automatically stop fuel flow and vent the engine if the engine is stopped for any reason?	X			
(e)	Are the mufflers equipped with vents to vent any trapped gas?	X			
.173	Is each compressor station building adequately ventilated?	X			
.457	Is all buried piping cathodically protected?	X			
.481	Atmospheric corrosion of aboveground facilities	X			
.603	Does the operator have procedures for the start-up and shut-down of the station and/or compressor units?	X			
	Are facility maps current/up-to-date?	X			

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) ____	S	U	N/A	N/C
.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:

-Station uses a centrifugal compressor and if any liquids are present in the gas stream they are passed down stream without affecting the compressor.

-The District does not supply gas to a LDC system.

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

	REPORTING PERFORMANCE and RECORDS	S	U	N/A	N/C
191.5	Immediate Notice Reports to NRC. ~~(800-424-8802)~~			X	
191.12	Mechanical Fitting Failure Report (DOT Form PHMSA 7100.1-2) - if a fitting failure happened in the previous year.			X	
191.15	Written incident reports; supplemental incident reports (DOT Form PHMSA F 7100.2)			X	
191.17 (a)	Annual Report (DOT Form PHMSA 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			
.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			

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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CONSTRUCTION PERFORMANCE and RECORDS		S	U	N/A	N/C
.455	Cathodic Protection	X			

OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS			S	U	N/A	N/C
.10		**OUTER CONTINENTAL SHELF ONLY:** Operator has identified on pipeline(s) [or if subsea - on a schematic] the specific point(s) at which operating responsibility transfers to a producing operator.			X	
.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	2 Years
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.	

X

	.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 - as prescribed by **.555**, or **.557** as applicable.	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			
.709	.625	Odorization of Gas			X	

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS			S	U	N/A	N/C
.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:

The interstate pipeline gas is not odorized.

The District does not have vaults greater than 200 CF.

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			

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CORROSION CONTROL PERFORMANCE and RECORDS			S	U	N/A	N/C
.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:

192.465(d) Prompt Remedial Action

During the annual surveys for 2010 and 2011, the pipe-to-soil "off" potential was less than 100 mV with respect to the native potentials for the following locations:

At MP 110.2 the native potential is -698 mV and 2010 P/S was -669 mV and 2011 P/S was -748 mV, and

At MP 110.8 the native potential is -708 mV and 2010 P/S was -640 mV and 2011 P/S was -792 mV.

192.467 Electrical Isolation

During the annual survey for 2011 (August 2011) the "off" potential difference between the B-Line and its casing at MP 112 was not greater than 100 mV (P/S -0.444 V and casing -0.365 V) as required by GTN's Standards. I inspected the casing on November 30, 2011 and found the "on" potential difference to be greater than 100 mV. (P/S -0.556 V and casing -0.422 V). Rich Christman, GTN's Corrosion Specialist, is new to the District and has been working on evaluating the casing. He has several options including, expose and examine the casing, resurvey the native potentials or remove the casing. The casing is located at an abandoned railroad track and is adjacent to a new housing development.

Attachment 1
Alternative Maximum Allowable Operating Pressure

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

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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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	
.620(e)	(1) Provide overpressure protection to a max of 104% MAOP			X	
	(2) Procedure for establishing and maintaining set points for SCADA			X	

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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Comments:
The District does not use the Alternative MAOP.

Leave this list with the operator.

All PHMSA Advisory Bulletins (Last 2 years)

Number	Date	Subject
ADB-09-01	May 21, 2009	Pipeline Safety: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe
ADB-09-02	September 30, 2009	Pipeline Safety: Weldable Compression Coupling Installation
ADB-09-03	December 7, 2009	Pipeline Safety: Operator Qualification (OQ) Program Modifications
ADB-09-04	January 19, 2010	Pipeline Safety: Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-10-01	January 26, 2010	Pipeline Safety: Leak Detection on Hazardous Liquid Pipelines
ADB-10-02	February 3, 2010	Pipeline Safety - 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	Pipeline Safety: 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

OPERATOR QUALIFICATION
FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	November 28 to December 2, 2011
Name of Operator:	TransCanada U.S. Western Pipe Region
Operator ID (OPID):	15014
Inspection Location(s):	Spokane, WA
Supervisor(s) Contacted:	Kurt Smith, Pipe Regulatory Specialist
# Qualified Employees Observed:	Three
# Qualified Contractors Observed:	none

Individual Observed	Title/Organization	Phone Number	Email Address
Patrick Brown	Multi Skill Tech-Mechinal	509-523-4211	Pat_brown@transcanada.com
William (Bif) Hendrix	Multi Skill Tech-Controls	509-523-4211	Bif_hendrix@transcanada.com
Rich Christman	Corrosion Specialist	208-265-2164	Rich_christman@transcanada.com

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Al Jones / UTC	Western/WA	aljones@utc.wa.gov

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is on the last page of this form. This form is to be uploaded on to the OQBD for the appropriate operator, then imported into the file.

9.01 Covered Task Performance

Verify the qualified individuals performed the observed covered tasks in accordance with the operator's procedures or operator approved contractor procedures.

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.02 Qualification Status

Verify the individuals performing the observed covered tasks are currently qualified to perform the covered tasks.

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	I reviewed the current OQ completed skills for the above employees. Rich Christman has exceeded the minimum requirements and completed Level II for National Association Corrosion Engineers.
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.03 Abnormal Operating Condition Recognition and Reaction

Verify the individuals performing covered tasks are cognizant of the AOCs that are applicable to the tasks observed.

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	Bif was aware of safety precautions before opening a rectifier and the use of a multi-meter for C/P data.
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.04 Verification of Qualification

Verify the qualification records are current, and ensure the personal identification of all individuals performing covered tasks are checked, prior to task performance.

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	I reviewed the current OQ completed skills for the above employees.
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected at the operational level?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	Rich began working in reviewing C/P date late this year and has identified several areas that require additional studies.
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Field Inspection Notes

The following table is provided for recording the covered tasks observed and the individuals performing those tasks.

No	Task Name	Name/ID of Individual Observed			Comments
		Patrick Brown	Bif Hendrix	Rich Christman	
		Correct Performance (Y/N)	Correct Performance (Y/N)	Correct Performance (Y/N)	
1	Operate Main Line Valves	Y			
2	Review Field Safety Hazards	Y			Patrick did an excellent job in reviewing the safety hazards. He assisted with on-site safety for vehicle parking and precautions in operating main line valves.
3	Pipe-to-Soil (P/S) Potentials		Y		Bif was aware of safety precautions before opening a rectifier and the use of a multi-meter for C/P data.
4	Rectifier output potentials and amperage.		Y		
5	P/S data & trouble shooting low potentials			Y	Rich began working in reviewing C/P date late this year and has identified several areas that require additional studies.
6	Right-of-Way Conditions & Line markers	Y			
7	Security at Valve & Meter Stations	Y			
8	Check regulator settings	Y			

Operations and Maintenance Records Review

If performing an operations and maintenance records review in the course of your inspection, please review a sample of the qualifications of the individuals performing those O&M tasks that are covered under Operator Qualification and check the records for compliance to 192.807 or 195.507.

192.807 or 195.507	Records supporting an individual's current qualifications shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.	Sat. X	Unsat.	Not Checked
	Comments: I reviewed the current OQ completed skills for the above employees. Rich Christman has exceeded the minimum requirements and completed Level II for National Association Corrosion Engineers.			

US Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

Gas IMP Field Verification Inspection
49 CFR Subparts 192.911, 192.921, 192.933, & 192.935

General Notes:

1. This Field Verification Inspection is performed on field activities being performed by an Operator in support of their Integrity Management Program (IMP).
2. This is a two part inspection form:
   i. A review of applicable Operations and Maintenance (O&M) and IMP processes and procedures applicable to the field activity being inspected to ensure the operator is implementing their O&M and IMP Manuals in a consistent manner.
   ii. A Field Verification Inspection to determine that activities on the pipeline and facilities are being performed in accordance with written procedures or guidance.
3. Not all parts of this form may be applicable to a specific Field Verification Inspection, and only those applicable portions of this form need to be completed. The applicable portions are identified in the Table below by a check mark. Only those sections of the form marked immediately below need to be documented as either "Satisfactory"; "Unsatisfactory"; or Not Checked ("N/C"). Those sections not marked below may be left blank.

Operator Inspected: Gas Transmission Northwest Corporation (GTN)
Op ID: 15014

Perform Activity *(denoted by mark)*	Activity Number	Activity Description
	1A	In-Line Inspection
X	1B	Hydrostatic Pressure Testing
	1C	Direct Assessment Technologies
	1D	Other Assessment Technologies
	2A	Remedial Actions
	2B	Remediation – Implementation
	3A	Preventive & Mitigative – additional measures evaluated for HCAs
	3B	Preventive & Mitigative – automatic shut-off valves
X	4A	Field Inspection for Verification of HCA Locations
	4B	Field Inspection for Verification of Anomaly Digs
X	4C	Field Inspection to Verify adequacy of the Cathodic Protection System
X	4D	Field inspection for general system characteristics
	attachment	Anomaly Evaluation Report
	attachment	Anomaly Repair Report

Gas IMP Field Verification Inspection Form

Name of Operator:

Gas Transmission Northwest Corporation (GTN)

Headquarters Address:	1400 SW 5th Ave Suite 900 Portland, OR 97201
Company Official:	Ken Leier, Regional Director
Phone Number:	**509-533-2831**
Fax Number:	**509-533-2825**
Operator ID:	**15014**

Persons Interviewed	Title	Phone No.	E-Mail
Kurt Smith	**Compliance Specialist, Primary Contact**	509-546-8865	kurt_smith@transcanada.com

OPS/State Representative(s): Al Jones/WUTC **Date(s) of Inspection:** Nov. 28 – Dec. 2, 2011

Inspector Signature: *Al Jones* Date: December 22, 2011

Pipeline Segment Descriptions: *[note: Description of the Pipeline Segment Inspected as part of this field verification. (If information is available, include the pipe size, wall thickness, grade, seam type, coating type, length, normal operating pressure, MAOP, %SMYS, HCA locations, class locations, and Pipeline Segment boundaries.)]*

The sections of pipeline inspected include a 36-inch and two 42-inch diameter pipelines from the Washington/Idaho border (MP 106.8) to the Spokane Gate Station (MP 108.2). From Spokane two pipelines (36-inch and 42-inch) extent south to the Snake River crossing (MP 206.7). The Rosalia District is approximately 100 miles in length with a total of approximately 201 miles of piping.

Site Location of field activities: *[note: Describe the portion of the pipeline segment reviewed during the field verification, i.e. milepost/stations/valves/pipe-to-soil readings/river crossings/etc. In addition, a brief description and case number of the follow up items in any PHMSA compliance action or consent agreement that required field verification. Note: Complete pages 8 & 9 as appropriate.]*

The sites inspected include the compressor station located at Rosalia, including a Mars Solar (14K Hp), Titan Solar (19.5K Hp), and a LM-1500, GE (12.5K Hp) turbines, meter station located at Spokane Gate, St. John, and LaCrosse were inspected for regulator lockup, set point, overpressure protection, and the facilities in general. During the right-of-way inspection the line markers were inspected for emergency information, at C/P test sites include: casings, rectifier units and numerous pipe-to-soil readings (See Field Data Report for details). There are no direct sales customers.

Summary:

The pipeline integrity was improved with the replacement of 3,600 linear feet of 36-inch diameter pipe at Saltese Meadow located in Spokane Valley, WA. The new pipeline is located in a Class 3 location constructed to API 5L L485/X70, 0.500" wt, submerged arc weld (SAWH), and helical seam.

Findings:

The new Saltese Meadow pipeline has improved the pipeline integrity. Low pipe-to-soil readings were found near a casing (MP 112.0) in the Spokane Valley that was used for a railroad crossing. The rail tracks have been removed and a new housing development is located near the casing.

Key Documents Reviewed:

Document Title	Document No.	Rev. No	Date
Compressor Station – Emergency Shutdown (1 x per yr, 192.723(c))			**Jan 2010 – Nov 2011**
Compressor Stations – Relief Devices (1 x per yr, 192.731 (a))			**Jan 2010 – Nov 2011**
Rectifier Monitoring (6 x per yr, 192.465(b))			**Jan 2010 – Nov 2011**
Pipe-to-Soil Monitoring (1 x per yr, 192.465(a))			**Jan 2010 – Nov 2011**
Pressure Limiting & Regulating Stations (1 x per yr, 192.739)			**Jan 2010 – Nov 2011**
Valve Maintenance (1 x per yr, 192.745)			**Jan 2010 – Nov 2011**

Part 1 - Performance of Integrity Assessments

1A. In-Line Inspection	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that Operator's O&M and IMP procedural requirements (e.g. launching/receiving tools) for performance of ILI were followed.			X	
Verify Operator's ILI procedural requirements were followed (e.g. operation of trap for launching and receiving of pig, operational control of flow), as appropriate.				
Verify ILI tool systems and calibration checks before run were performed to ensure tool was operating correctly prior to assessment being performed, as appropriate.				
Verify ILI complied with Operator's procedural requirements for performance of a successful assessment (e.g. speed of travel within limits, adequate transducer coverage), as appropriate.				
Document ILI Tool Vendor and Tool type (e.g. MFL, Deformation). Document other pertinent information about Vendor and Tool, as appropriate				
Verify that Operator's personnel have access to applicable procedures for preparing, running and monitoring the pipeline for ILI tools include performance requirements (e.g.: tool speeds, pipe cleanliness, operation of tool sensors, and ILI field calibration requirements), as appropriate.				*[Note: Add location specific information, as appropriate.]*
Other:				

1B. Hydrostatic Pressure Testing	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that hydrostatic pressure tests complied with Part 192 Subpart J requirements.	X			Reviewed pressure and temperature recording charts, dead weight data, and certification documents for each instrument.
Review documentation of Hydrostatic Pressure Test parameters and results. Verify test was performed without leakage and in compliance with Part 192 Subpart J requirements.				
Review test procedures and records and verify test acceptability and validity.				
Review determination of the cause of hydrostatic test failures, as appropriate.				
Document Hydrostatic Pressure Test Vendor and equipment used, as appropriate.				
Verify that the baseline assessment is conducted in a manner that minimizes environmental and safety risks (reference §192.919(e) and ADB-04-01)				
Other:				

1C. Direct Assessment Technologies	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that application of "Direct Assessment Technology" complied with Part 192.923			X	
Review documentation of Operator's application of "Direct Assessment Technology", if available. Verify compliance with Part 192.923 and Operator's procedural requirements, as applicable.				
Verify that appropriate tests and/or inspections are being performed and appropriate data is being collected, as appropriate.				
Other.				

1D. Other Assessment Technologies	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that application of "Other Assessment Technology" complied with Operator's requirements, that appropriate notifications had been submitted to PHMSA, and that appropriate data was collected.			X	
Review documentation of notification to PHMSA of Operator's application of "Other Assessment Technology", if available. Verify compliance with Operator's procedural requirements. If documentation of notification to PHMSA of Operator's application of "Other Assessment Technology" is available, verify performance of assessment within parameters originally submitted to PHMSA.				
Verify that appropriate tests are being performed and appropriate data is being collected, as appropriate.				
Other.				

Part 2 - Remediation of Anomalies

2A. Remedial Actions – Process	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that remedial actions complied with the Operator's procedural requirements.			X	
Witness anomaly remediation and verify documentation of remediation (e.g. Exposed Pipe Reports, Maintenance Report, any Data Acquisition Forms). Verify compliance with Operator's O&M Manual and Part 192 requirements.				
Verify that Operator's procedures were followed in locating and exposing the anomaly (e.g. any required pressure reductions, line location, identifying approximate location of anomaly for excavation, excavation, coating removal).				
Verify that procedures were followed in measuring the anomaly, determining the severity of the anomaly, and determining remaining strength of the pipe. Review the class location factor and failure pressure ratio used by Operator in determining repair of anomaly.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: _____ mV Off Potential: _____ mV *[Note: Add location specific information and note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*
Verify that Operator's personnel have access to and knowledge of applicable procedures.				
Other:				

2B. Remediation - Implementation	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that the operator has adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis.			X	
If documentation is available, verify that repairs were completed in accordance with the operator's prioritized schedule and within the time frames allowed in §192.933(d).				
Review any documentation for this inspection site for an immediate repair condition (§192.933(d)(1)) where operating pressure was reduced or the pipeline was shutdown. Verify for an immediate repair condition that temporary operating pressure was determined in accordance with the requirements in §192.933(a) or, if not applicable, the operator should provide an engineering basis justifying the amount of pressure reduction.				
Verify that repairs were performed in accordance with §192.103, §192.111, §192.713, §192.717, §192.719, §192.933 and the Operator's O&M Manual, as appropriate. If welding is performed, verify a qualified welding procedure and qualified welders are used to perform repairs. If composite repair methods are used, verify that a method approved by the Operator is used, procedures are followed, and qualified personnel perform the repair.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: _____ mV Off Potential: _____ mV *[Note: Add location specific information and note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*
Review CP readings at anomaly dig site, if possible. (See Part 4 of this form – "Field Inspection to Verify adequacy of the Cathodic Protection System" , as appropriate.				
Other:				

Part 3 - Preventive and Mitigative Actions

3A. P&M Measures for Third Party Damage	Satisfactory	Unsatisfactory	N/C	Notes:
Identify additional measures evaluated for the HCA section of the pipeline and facilities.			X	
Verify that P & M measures regarding threats due to third party damage are being implemented: [§192.915(c), §192.935(b)(1)(iv)]:				
Confirm the use of qualified personnel for marking, locating, and direct supervision of known excavation work, as appropriate.				
Confirm the use of qualified personnel for monitoring of excavations conducted on covered pipeline segments by pipeline personnel, as appropriate.				
Other:				*[Note: Add location specific information, as appropriate.]*

3B. Installed Automatic Shut-off Valves (Protocol H.07)	Satisfactory	Unsatisfactory	N/C	Notes:
Verify additional preventive and mitigative actions implemented by Operator.			X	
Document that additional measures evaluated by the operator cover alternatives such as, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs, as appropriate				
Verify that the operator has a process to decide if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. [§192.935(c)]				
Verify operation of installed remote control valve by reviewing operator inspection/remote control records for partially opening and closing the valve, as appropriate.				
Other:				*[Note: Add location specific information, as appropriate.]*

Part 4 - Field Investigations (Additional Activities as appropriate)

4A. Field Inspection for Verification of HCA Locations	Satisfactory	Unsatisfactory	N/C	Notes:
Review HCAs locations as identified by the Operator. Utilize NPMS and Operator maps, as appropriate.	X			
Verify that the operator's integrity management program includes accurate and updated system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas, as appropriate. [§192.905(a)]				Field inspected Saltese Meadows development and proximity to pipeline right-of-way. Development is located in Spokane Valley, WA. Approximately, 3,600 linear feet of the 36-inch diameter A-Line was replaced.
Review the operator's applicable procedures and forms used to document new information from one-calls, surveys, aerial & ground patrols are being completed by field personnel to communicate new developments that may impact high consequence areas or that may create new high consequence areas to IM personnel, as appropriate. [§192.905(c)]				
Review the operator's applicable procedures and forms to confirm that new HCAs and class location changes are being identified through it's continuing surveillance program as required by §192.613 and §192.905.				*[Note: Add location specific information, as appropriate.]*

4B. Field Inspection for Verification of Anomaly Digs	Satisfactory	Unsatisfactory	N/C	Notes:
Verify repair areas, ILI verification sites, etc.			X	
Document the anomaly dig sites observed and reviewed as part of this field activity and the actions taken by the operator.				*[Note: Add location specific information, as appropriate.]*

4C. Field Inspection to Verify adequacy of the Cathodic Protection System	Satisfactory	Unsatisfactory	N/C	Notes:
In case of hydrostatic pressure testing, Cathodic Protection (CP) systems must be evaluated for general adequacy.	X			
The operator should review the CP system performance in conjunction with a hydrostatic pressure test to ensure the integrity assessment addressed applicable threats to the integrity of the pipeline. Has the operator reviewed the CP system performance in conjunction with the hydrostatic pressure test?				Review records for CP readings and rectifier output values for 2010 and 2011. Field checked pipe-to-soil and rectifier output values are various locations along the pipeline.
Review records of CP readings from CIS and/or annual survey to ensure minimum code requirements are being met, if available.				
Review results of random field CP readings performed during this activity to ensure minimum code requirements are being met, if possible. Perform random rectifier checks during this activity and ensure rectifiers are operating correctly, if possible.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: _____mV Off Potential: _____mV *[Note: Add location specific information and note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*

4D. Field inspection for general system characteristics	Satisfactory	Unsatisfactory	N/C	Notes:
Through field inspection determine overall condition of pipeline and associated facilities for a general estimation of the effectiveness of the operator's IMP implementation.	X			Field reviewed the pipeline right-of-way and line markers.

Evaluate condition of the ROW of inspection site to ensure minimum code requirements are being met, as appropriate.	
Comment on Operator's apparent commitment to the integrity and safe operation of their system, as appropriate.	
Check ROW for pipeline markers in line-of-sight and Emergency call-in number on marker posts.	
Other:	

Anomaly Evaluation Report *(to be completed as appropriate)*

Pipeline System and Line Pipe Information	
Operator (OpID and System Name):	
Unit ID (Pipeline Name)	
Pipe Manufacturer and Year:	Seam Type and Orientation:
Pipe Nominal OD (inch):	Depth of Cover:
Pipe Nominal Wall thickness (inch):	Coating Type and Condition:
Grade of Pipe:	MAOP:
ILI Reported Information	
ILI Technology (e.g., Vendor, Tools):	
Anomaly Type (e.g., Mechanical, Metal Loss):	
Is anomaly in a segment that can affect an HCA? (Yes / No)	
Date of Tool Run (MM/DD/YY):	Date of Inspection Report (MM/DD/YY):
Date of "Discovery of Anomaly" (MM/DD/YY):	
Type of "Condition" (e.g.; Immediate; 60-day; 180-day):	
Anomaly Feature (Int/Ext):	Orientation (O'clock position):
Anomaly Details: Length (in):	Width (in): Depth (in):
Anomaly Log Distance (ft):	Distance from Upstream weld (ft):
Length of joint(s) of pipe in which anomaly is identified (ft):	
Anomaly Dig Site Information Summary	
Date of Anomaly Dig (MM/DD/YY):	
Location Information (describe or attach map):	
Mile Post Number:	Distance from A/G Reference (ft):
Distance from Upstream weld (ft):	
GPS Readings (if available) Longitude:	Latitude:
Anomaly Feature (Int/Ext):	Orientation:
Length of joint of pipe in which anomaly is found (ft):	
For Mechanical Damage Anomaly	
Damage Type (e.g., original construction, plain dent, gouge):	
Length (in):	Width (in): Depth (in):
Near a weld? (Yes / No):	
Gouge or metal loss associated with dent? (Yes / No):	Are multiple dents present? (Yes / No):
Did operator perform additional NDE to evaluate presence of cracks in dent? (Yes / No):	
Cracks associated with dent? (Yes / No):	
For Corrosion Metal Loss Anomaly	
Anomaly Type (e.g., pitting, general):	
Length (in):	Width (in): Max. Depth (in):
Remaining minimum wall thickness (in):	Maximum % Wall Loss measurement(%):
Safe pressure calculation (psi), as appropriate:	
For "Other Types" of Anomalies	
Describe anomaly (e.g., dent with metal loss, crack, seam defect, SCC):	
Length (in):	Width (in): Max. Depth (in):
Other Information, as appropriate:	
Did operator perform additional NDE to evaluate presence of cracks? (Yes / No):	
Cracks present? (Yes / No):	

Anomaly Repair Report *(to be completed as appropriate)*

Repair Information
Was a repair of the anomaly made? (Yes / No): Was Operating Pressure Reduced per 192.933(a) requirements?
Was defect ground out to eliminate need for repair? (Yes / No):
If grinding used, complete the following for affected area: Length (in): Width (in): Depth (in):
If NO repair of an anomaly for which RSTRENG/B31.G is applicable, were the Operator's RSTRENG/B31.G calculations reviewed? (Yes / No):
If Repair made, complete the following:
Repair Type (e.g., Type B-sleeve, composite wrap)
Was defect ground out prior to making repair? (Yes / No):
Operating Pressure at the time of repair:
Length of Repair: Pipe re-coating material used:
Comments on Repair material, as appropriate (e.g., grade of steel, wall thickness):
Comments on Repair procedure, as appropriate (e.g., welded sleeve, composite wrap):
General Observations and Comments
Was a diagram (e.g., corrosion map) of the anomaly made? (Yes / No): (Include in report if available)
Were pipe-to-soil cathodic protection readings taken? (Yes / No):
If CP readings taken, Record: On Potential: _____mV; Off Potential: _____mV *[Note: Note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*
Describe method used by Operator to locate anomaly (as appropriate):
Comments regarding procedures followed during excavation, repair of anomaly, and backfill (as appropriate):
General Observations and Comments *(Note: attach photographs, sketches, etc., as appropriate)*:

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

1. Pipeline Safety Advisory Bulletin - ADB-03-05 - October 8, 2003
   - Review Bulletin with operator, if operator is not familiar with.
   - Reference also Baker Stress Corrosion Cracking Study at:
   http://primis.phmsa.dot.gov/gasimp/docs/SCC_Report-Final_Report_with_Database.pdf

Comments:
Yes, TransCanada is aware of the SCC threat to pipelines and has identified SCC as a threat of concern to the GTN Pipeline.

2. Has the pipeline system ever experienced SCC (in service, out of service, leak, non-leak)?
   - Type of SCC?
     Classical - high pH
     Non-classical – low or near neutral pH
   - What are the known risk indicators that may have contributed to the SCC?

Comments:
The GTN operational staff has not reported occurrence of SCC. The GTN A-Line is at risk as per ASME B311.8S (age of pipe > 10 years, operating stress > 60 % SMYS, and coating other than FBE).

3. Does the operator have a written program in place to evaluate the pipeline system for the presence of SCC? If no, have operator explain. If operator has not considered SCC as a possible safety risk, go to #10.

Comments:
Yes, the SCC Direct Assessment (SCCDA) Procedure in conjunction with other company standards, processes and procedures. TransCanada's SCCDA Procedure was audited by PHMSA and the WUTC in August/September 2010.

4. Has/does the operator evaluate the pipeline system for the presence of SCC risk indicators?

Comments:
Yes, TransCanada completed a risk assessment of the entire pipeline system, not just the HCA's

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

5. Has the operator identified pipeline segments that are susceptible to SCC?

Comments:
Yes, mostly on the A-Line has been identified as SCC susceptible.

6. If conditions for SCC are present, are written inspection, examination and evaluation procedures in place?

Comments:
TransCanada uses its own Threat Identification process to determine if SCC conditions are present. This process allows the company to evaluate the presence of SCC and its corresponding threat level (e.g. low, medium, high). Based on the threat level classification TransCanada will determine the type of assessment. Assessments have prescribed examination and evaluation procedures in place in order to assess the presence of SCC on TransCanada's system. To date, no SCC has been identified on the GTN system, despite the fact that TransCanada diligently looks for evidence of SCC on all opportunistic and targeted excavations.

7. Does the operator have written remediation measures in place for addressing SCC when discovered?

Comments:
Yes, TransCanada has a procedure, 'Repair of Pipeline Defects and Imperfections'.

8. What preventive measures has the operator taken to prevent recurrence of SCC?
    - Modeling?
        - Crack growth rate?
        - Comparing pipe/environ./cp data vs. established factors?
        - Other?
    - Hydrotest program?
    - Intelligent pigging program?
    - Pipe re-coating?
    - Operational changes?
    - Inspection program?
    - Other?

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

Comments:

TransCanada has preventative condition monitoring and mitigative options combined with re-assessment guidelines depending of SCC detected where there is an ident9ified threat. In addition, TransCanada maintains adequate Cathodic Protection on the entire GTN system as per NACE guidelines and Federal Regulations.

9. Does the operator incorporate the risk assessment of SCC into a comprehensive risk management program?

Comments:

Yes, TransCanada utilized a quantitative risk assessment process (PRIME) to model the threat of SCC.

Continue below for those operators who have not considered SCC as a possible safety risk.

10. Does the operator know of pipeline and right of way conditions that would match the risk indicators for either classical or non-classical SCC? See typical risk indicators below.

Comments:

Yes, the SCCDA plan includes reference to these risk indicators. As indicated, above the A-Line is recognized as a threat of SCC.

High pH SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
    - Age ≥ 10 years
    - Operating stress > 60% SMYS
    - Pipe temperature >100 deg. F (typically < 20 miles d/s of compression)
    - Damaged pipe coating
- Soil Characteristics
    - Soil pH range: 8.5 to 11
    - Alkaline carbonate/bicarbonate solution in the soil
    - Elevated soil temperature contributing to elevated pipe temperature
- Polarized cathodic potential range: -600 to -750 mV, Cu/$CuSO_4$

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

Low or Near-Neutral pH SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
    - Age ≥ 10 years
    - Frequently associated with metallurgical features, such as mechanical damage, longitudinal seams, etc.
    - Protective coatings that may be susceptible to disbondment
        - Any coating **other than** correctly applied fusion bonded epoxy, field applied epoxies, or coal tar urethane . . .
        - Coal tar
        - Asphalt enamels
        - Tapes
        - Others
- Soil Characteristics
    - Soil pH range: 4 to 8
    - Dissolved CO_2 and carbonate chemicals present in soil
    - Organic decay
    - Soil leaching (in rice fields, for example)

- "Normal" cathodic protection readings (disbonded coating shields the pipe from cp current)

PUBLIC AWARENESS PROGRAM FIELD AUDIT

Audit Date:	Name of Operator: Gas Transmission Northwest Corporation (GTN)
H.Q. Address	Company Official: Ken Leier
	Title: Regional Director
	Phone number: 509-533-2831
	Fax Number: 509-533-2825
Inspection Team:	Operator Personnel in Interview: (Name & Phone Number)
1. Al Jones UTC	1. Kurt Smith, Compliance Specialist, GTN
2.	2. Verlyn L. Bailly, Community Relations Specialist
3.	3.

Instructions: Check (or mark) the appropriate box: "Yes," "No" or "N/A." If further comments are necessary, check (or mark) the comment box and write the comment in the "comments" section below the questions and/or attach a comments sheet when necessary. **These questions are to be verified in the field. Certain questions will have corresponding Desk Audit questions on a separate audit form.**

			Yes	No	N/A	Comment
1.	**1162 Section 2: Management Commitment** **(Must be verified in field if no PHYSICAL copy included in plan)**					
	a. Does the statement include the name and title of the appropriate authority (the person(s) with authority to authorize funding)?		X			
	b. Does the statement include the signature of the appropriate authority (the person(s) with authority to authorize funding)?		X			
	c. Are copies of approved city ordinances, etc., included where applicable				X	
2.	**1162 Section 4: Message Content** **(These are required in written plan. They will need verification in field)**					
Affected Public: **Including customers & residents living along the pipeline route**	a. pipeline purpose and reliability		X			
	b. hazards & prevention measures undertaken [192.616(d)(2)]		X			
	c. leak recognition and response [192.616(d)(3 &4)]		X			
	d. damage prevention awareness		X			
	e. how and where to get more information		X			
	f. One-call requirements [192.616(d)(1)]		X			
	g. Emergency communications [192.616(d)(5)]		X			
Emergency Officials	a. pipeline purpose and reliability		X			
	b. hazards & prevention measures undertaken [192.616(d)(2)]		X			
	c. leak recognition and response [192.616(d)(3 &4)]		X			
	d. emergency preparedness and response		X			
	e. how and where to get more information		X			
	f. emergency communications [192.616(d)(5)]		X			
	g. One-call requirements [192.616(d)(1)]		X			

Comments:
Affected Public (questions a –g) are contained in TransCanada Operating Procedure (TOP) Integrated Public Awareness, Rev. 2, Eff. Date 3/13/2006 Sections 4.1 and 4.2.
Emergency Officials (questions a-g) are contained in TOP Integrated Public Awareness, Rev. 2, Eff. Date 3/13/2006 Section 4.3.

		Yes	No	N/A	Com-ment
2. (Continued)	**1162 Section 4: Message Content** **(These are required in written plan. They will need verification in field)**				
Local Public Officials	a. pipeline purpose and reliability	X			
	b. hazards & prevention measures undertaken [192.616(d)(2)]	X			
	c. leak recognition and response [192.616(d)(3 &4)]	X			
	d. emergency preparedness and response	X			
	e. right-of-way encroachments	X			
	f. how and where to get more information	X			
	g. emergency communications [192.616(d)(5)]	X			
	h. construction/maintenance activities	X			
	i. One-call requirements [192.616(d)(1)]	X			
Excavators/ Contractors	a. pipeline purpose and reliability	X			
	b. hazards & prevention measures undertaken [192.616(d)(2)]	X			
	c. leak recognition and response [192.616(d)(3 &4)]	X			
	d. damage prevention awareness	X			
	e. pipeline location information	X			
	f. how and where to get more information	X			
	g. One-call requirements [192.616(d)(1)]	X			
	h. emergency communications [192.616(d)(5)]	X			
3.	**1162 Section 4 (4.4.1): PRIORITY MESSAGE** **(Message should be written in plan and verified in Field) Does the program identify the message for Emergency and Public Officials as protecting people first and then property as the TOP priority message?**				

Comments:
Local Public Officials (questions a-i) are contained in TOP Integrated Public Awareness, Rev. 2, Eff. Date 3/13/2006 Section 4.3.

Excavators/Contractors (questions a-h) are contained in TOP Integrated Public Awareness, Rev. 2, Eff. Date 3/13/2006 Section 4.5.

		Yes	No	N/A	Com-ment
4.	**1162 Section 5: Delivery Method**				
Affected Public:	**(From written plan – Does operator provide applicable documentation?)**				
LDC Customers	1. Bill Stuffer – required minimum			X	
Baseline	1. Public service announcements			X	
	2. Paid Advertising			X	
	3. Other:			X	
Supplemental	1. Public service announcements			X	
	2. Paid advertising			X	
	3. Targeted distribution of print material			X	
	4. Newspaper and magazine advertisements			X	
	5. Community events			X	
	6. Community newsletters			X	
	7. Other:			X	
Emergency Officials:	**(From written plan – Does operator provide applicable documentation?)**				
Baseline:	1. Print Materials	X			
	2. Group Meetings	X			
	3. Other	X			
Supplemental:	1. Telephone calls	X			
	2. Personal contact	X			
	3. Videos and/or CDs	X			
	4. Other:	X			
Local Public Officials:	**(From written plan – Does operator provide applicable documentation?)**				
Baseline:	1. Targeted distribution of printed materials	X			
	2. Other	X			
Supplemental:	1. Group meetings	X			
	2. Telephone calls	X			
	3. Personal contact	X			
	4. Other	X			
Excavators/ Contractors	**(From written plan – Does operator provide applicable documentation?)**				
Baseline:	1. Once-Call center outreach	X			
	2. Group meetings	X			
	3. Other	X			
Supplemental	1. Personal contact	X			
	2. Videos and/or CDs	X			
	3. Open houses		X		
	4. Targeted distribution of print materials	X			
	5. Other	X			

Comments:

Delivery Method and/or Media is contained in TOP Integrated Public Awareness, Rev. 2, Eff. Date 3/13/2006 Table 2-1.1 Affected Public, Table 2-1.2 Local Public Officials, Table 2-1.5, Excavators, and Table 2-1.6 Emergency Officials.

		Yes	No	N/A	Com-ment
5.	**1162 Section 5: Delivery Frequencies** **(These are required in the written plan)**				
Affected Public:					
LDC Customers?	Does documentation show at least twice per year?			X	
Residents along the LDC system?	Does documentation show at least once per year?			X	
Emergency Officials	Does documentation show at least once per year?	X			
Local Public Officials	Does documentation show at least once every three years?	X			
Excavators/ Contractors	Does documentation show at least once per year?	X			
6.	**1162 Section 6: Supplemental messages:** **Does the plan consider whether supplemental messages are necessary for special circumstances and explain why or why not? (These will need to be verified in field where applicable)**	X			
	Circle the examples below that apply:				
	1. Large excavator projects				
	2. Non-resident business owners (i.e., just workers occupy buildings(s) - owner that receives bill is in another location and/or state and tenant farmers)				
	3. Farming activities				
	4. Railroads				
	5. Other				
7.	**1162 Section 7: Program Implementation**				
	Is there documentation verifying the program has been implemented?	X			

8.	**1162 Section 7: Recordkeeping**	LDC Public	Emer. Ofls	Pub. Ofls	Excavator/ Contractor	N/A	Com-ment
	Can the Operator Document the following: (Write "Y" for Yes" and "N" for No under each applicable stakeholder audience)						
	a. Lists, Records and other documentation of stakeholder audiences?	Y	Y	Y	Y		
	b. Copies of all materials used?	Y	Y	Y	Y		
	c. Records of payments for mailings, advertisements, printing and other expenditures indicating the program was implemented?	Y	Y	Y	Y		
	d. Records of effectiveness assessments?	Y	Y	Y	Y		
	e. Records of annual assessments and/or audits?	Y	Y	Y	Y		
	f. Any record of feedback received and collected from audiences in response to the program?	Y	Y	Y	Y		
	g. Records of follow-up actions and expected results	N	N	N	N		
	h. Have records been maintained for five (5) years?	Y	Y	Y	Y		

Comments:

		Yes	No	N/A	Com-ment
9.	**1162 Section 8: ANNUAL REVIEW** **(This is required in the written plan – needs field documentation.)**				
	a. Does the annual audit ensure the Plan meets the minimum requirements of the regulation?	X			
	b. Does the annual audit ensure all actions called for in the Plan have been carried out as specified in the Plan?	X			
	c. Are records of the annual audit maintained by the Program Administrator?	X			
10.	**1162 Section 8: Evaluation Results**				
	Has the operator issued the results of the evaluation (review), shared it with upper management and sought internal feedback?	X			
11.	**1162 Section 8: Continuous Improvement Conducted:**				
	a. Has the operator modified its program based on its evaluation?	X			
	b. Are these changes documented?	X			
	c. Have these changes been implemented?	X			
	COMMENTS:				
12.	**1162 Section 8: Effectiveness Assessment** **(This is required upon design or re-design of materials and/or messages)**				
	a. Pre-tested Materials:				
	b. Date Pre-test conducted:	X			
13.	**1162 Section 8: Effectiveness Assessment** **(Required to be done no more than FOUR years apart)**				
	a. Last Survey of Targeted Audiences:: 3/3/2006				
	b. Date of last effectiveness assessment: 3/3/2006				
	c. Has the operator documented the results of evaluating the program for effectiveness?	X			
	Explain:				

Comments:

Field Data Collection
(2011 Standard Inspection)

Company: Gas Transmission Northwest Corporation (GTN)
Unit: Rosalia District
Inspector: Al Jones, UTC Staff

Pipe-to-soil potential readings and other items

Please note: The A, B, and C lines are 36, 42, and 42 inch diameter pipelines, respectively. The A-Line at Saltese Meadows is located in a Class 3 Location in Spokane Valley was replaced in October 2011. The C-Line extends from Canada through Idaho and terminates at the Spokane Gate Station.

Date	Location	Pipe (Volts DC)	Casing (Volts DC)	Comments
11/30/2011	MP 112.0 Abandoned RR tracts adjacent to a housing development	-0.699 -0.701 -0.555 -0.556	-0.188 -0.197 -0.376 -0.422	A-Line (100 feet upstream) A-Line (100 feet downstream) B-Line (100 feet upstream) B-Line (100 feet downstream)
11/30/2011	MP 115.2 (C/P Test Station)	-1.184 -1.168		New A-Line (100 feet upstream) New A-Line (100 feet downstream)
11/30/2011	MP 115.6 Valve Site 5-25 32nd St., Spokane Valley	-1.19 -1.21		"A" Line "B" Line
11/30/2011	Spokane Gate 6112 N. Starr Rd. (Valve 5.2) Spokane Valley	-0.3.343 -7.346 -3.32 -4.05 -3.08 -3.05	<Insulated Flange> <Insulated Flange> <Insulated Flange>	4" Kellogg Line at PGT side. 4" Kellogg Line at Williams side. 6" Line at GTN side. 6" Line at Avista Utilities side. 6" buried line to heater from GTN. 6" buried line from heater to meter station at Avista Utilities side. Operated Main Line valve A-1. OK.
11/30/2011	MP 116.6 Linke Rd. Crossing	-1.555 -0.240 -1.225		"A" Line "A" Line Casing "B" Line
11/30/2011	MP 143.6 Rosalia Compressor #6 E 315 Babb Rd. Rosalia, WA Compressors include Solar Turbines: 14,000 hp Mars 19,500 hp Titan, and 12,500 hp LM 1500 (GE)	-5.446		Utility fuel gas line to station furnace and hot water tank. Tested gas sensors for Control Room furnace / hot water room, A-Unit, and B-Unit compressor buildings. The sensors functioned correctly by alarmed at 10% LEL and ESD at 25% LEL. **Rectifier:** 39.9 v DC output

Date	Location	Pipe (Volts DC)	Casing (Volts DC)	Comments
				15.6 Amps output Settings: B-course, 4-fine
12/1/2011	MP 160.2 Main Line Valve 6-1	 -1.257 -1.27 1.256		 A-Line Test Station B- Line Test Station P/S at Main Line Valve A-1. Operated Main Line valve A-1. OK.
12/1/2011	Main Line Valve 6-2	-0.716 -0.810 -0.818	 -0.522 n/a	At Valve A-1 A-Line Test Station B- Line Test Station Operated Main Line valve A-1. OK.
12/1/2011	MP 182.8 - LaCrosse Meter & Rectifier Stations	-3.28 -3.74	-0.037	"A" Line "B" Line **Rectifier:** 79.23 v DC output 14.73 Amps output Settings: D-course, 2-fine **Meter Station:** Tested the monitor regulator on the primary supply. The gas delivery to Avista distribution was held at 150 psig.
12/1/2011	Meter Station at: St. John MP 158.9	-1.226 on		Avista C/P -1.11 v with a 150 psig delivery pressure. Insulator is shorted at flange connection with Avista Utilities.
12/1/2011	MP 194.0 Rectifier at Rock Spring			44.33 v DC output 16.5 Amps output Settings: D-course, 2-fine
12/1/2011	MP 197.8 Valve 6-3	-0.852 -0.6295 -0.713	 -0.765 -0.780	A-Line, Valve A-1 A-Line at test station B-Line at test station At south end of A-Line casing. At north end of A-Line casing. **Note:** **Except for the valve, the P/S readings for the casing are greater than the A-Line value.**

Date	Location	Pipe (Volts DC)	Casing (Volts DC)	Comments

TransCanada - 2011 Rosalia District Inspection - Data Request #2

Kurt, please provide at the following locations the latest native and the most recent pipe-to-soil values.
Please provide the date when the data was taken. Thank you, -Al

		P/S Potentials		2011 Annual Survey			2011	
Location	MP	Date	Native	Date	ON	Off	Field Insp	Comments
A-Line	197.8						-0.6295	At Test Point
A-Line	197.8						-0.78	North end of Casing
A-Line	197.8						0.765	South end of Casing
B-Line	197.8						-0.713	At Test Point
Valve 6.2								
A-Line							-0.716	At Valve A-1
A-Line							-0.81	At Test Point
A-Line							-0.522	At Casing
B-Line							-0.818	AT test point

Requested Data Follow-up: See Below for notes and Data

Notes: **MLV 6-2 :**

Data- supplied data for this year's Annual Test Lead (ATL) surveys and Depol data
New readings for this location, data gathered after Rectifer adjustments which occurered after 2011 ATL survey. (12/9/2011)
Readings with depol data show greater than 100mV depol shift criteria has been met
New Depol scheduled for Rosalia area in 2012

Notes: **M.P 197.8 / MLV 6-3:**

Data- supplied for 2011 ATL survey and Depol data
New readings for this location, data gathered after Rectifer adjustments which occurered after 2011 ATL survey. (12/9/2011)
Readings with depol data show greater than 100mV depol shift criteria has been met
New Depol scheduled for Rosalia area in 2012
The Casing and pipe potentials can be at different potentials due to them being separate structures.
The Casing values do not shift during the ON/OFF survey which indicates casing is not shorted
The Casing values being at a higher potential than the carrier pipe can be caused by many things, such as the possibility of old Mags being directly connected to casing, casing material, or even soil chemistry and conditions. Please note that the casing does not shift with the pipe indicating no short. A casing test have been completed in Dec 2009 also indicating casing is not shorted to carrier piping.

MP 197.8 Requested Data

Name Plate Change		Date	Native	Date / Time	Casing Readings		Pipe Line Readings		Note:
5006301+197.800-TS	A - Line MP 197.8	Oct-06	0.397	8/17/2011			0.593	0.540	2011 ATL Survey (Annual Test Lead Survey)
5006301+197.800-TS	A - Line MP 197.8			12/9/2011			0.598	0.568	2011 Follow up Readings - Readings taken with Fluke Meter
5006301+197.800-TS	A - Line MP 197.8			8/17/2011	0.883	0.885			2011 ATL Survey
5006301+197.800-TS	A - Line MP 197.8			12/9/2011	0.741	0.743			2011 Follow up Readings - Readings taken with Fluke Meter (south end)
5006301+197.800-TS	A - Line MP 197.8			12/9/2011	0.738	0.736			2011 Follow up Readings - Readings taken with Fluke Meter (north end)
5006302+197.800-TS	B - Line MP 197.8	Oct-06	0.414	8/17/2011			0.633	0.573	2011 ATL Survey
5006302+197.800-TS	B - Line MP 197.8			12/9/2011			0.686	0.617	2011 Follow up Readings - Readings taken with Fluke Meter

Valve 6.2 Requested Data

Name Plate Change	Test Lead Comment	Date	Native	Date / Time			ON Potential	OFF Potential	Measurement Comment
5006201+179.020V-2-TS	mlv 6-2 A-LINE VALVE #A-1	Oct-06	0.485	09-Dec-2011			0.774	0.712	mlv 6-2 A-LINE VALVE #A-1
5006201+179.020V-2-TS	mlv 6-2 A-LINE VALVE #A-1	Oct-06	0.485	18-Aug-2011			0.541	0.449	mlv 6-2 A-LINE VALVE #A-1
5006201+179.020V-2-TS	mlv 6-2 A-LINE VALVE #A-1	Oct-06	0.485	20-Aug-2010			0.774	0.903	mlv 6-2 A-LINE VALVE #A-1

Name Plate Change		Date	Native	Date / Time	Casing Readings		Pipe Line Readings		Note:
5006201+179.000-TS	A - Line MP 179.0	Oct-06	0.345	8/18/2011			0.794	0.656	2011 ATL Survey
5006201+179.000-TS	A - Line MP 179.0			12/9/2011			0.769	0.693	2011 Follow up Readings - Readings taken with Fluke Meter
5006201+179.000-TS	A - Line MP 179.0			8/18/2011	0.531	0.530			2011 ATL Survey
5006201+179.000-TS	A - Line MP 179.0			12/9/2011	0.494	0.494			2011 Follow up Readings - Readings taken with Fluke Meter (south end)
5006202+179.000-TS	B - Line MP 179.0	Oct-06	0.385	8/18/2011			0.811	0.671	2011 ATL Survey
5006202+179.000-TS	B - Line MP 179.0			12/9/2011			0.781	0.685	2011 Follow up Readings - Readings taken with Fluke Meter

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PART A - OPERATOR INFORMATION

Pipeline operator/owner:	**OPID #:**
Gas Transmission Northwest Corporation (GTN)	15014

Company Official name, title, telephone, FAX #:	**Mailing address of Company Official:**
Ken Leier, Regional Director	201 West North River Drive
Tel: 509-533-2831 FAX: 509-533-2825	Spokane, Washington 99201

Nature and size of operator's system (total miles, HCA miles, products, environmental conditions, employees):
The Rosalia District is located in Spokane and Whitman Counties of eastern Washington and extends south from the Idaho/Washington border to the Snake River crossing. The natural gas pipeline is approximately 100 miles in length. The transmission lines are primarily in Class-1 Location, except the Spokane Valley has about 13 miles of Ecological HCA and about 8 miles of population HCA Class-3 Location. The compressor station is located Rosalia, WA.

PART B - INSPECTION RESULTS

Date of Inspection:	[x] **Gas** [ ] **LNG**	**Unit #(s):**
November 28 – December 2, 2011	[ ] **Hazardous Liquid**	15014

PHMSA/State Inspector name and organization:
Al Jones / UTC

Inspection location(s) and facilities inspected:
The Rosalia District is located in Eastern Washington with their office at Spokane, WA. The portion of the District inspected include the 36-inch (A-Line) and two 42-inch (B-Line and C-Line) diameter pipelines from the Washington/Idaho border (MP 106.8) to the Spokane Gate Station (MP 108.2). In 2011about 3,600 linear feet of the A-line located at Saltese Meadows in Spokane Valley was removed and replaced

with a new 36-inch diameter pipeline with FBE coating in a Class-3 Location. The A and B Lines extents south from the Spokane Gate to the Snake River (MP 206.7). The Rosalia Compressor Station contains a Mars Solar (14K Hp), Titan Solar (19.5 Hp), and a LM-1500, GE (12.5 Hp) turbines. Meter Stations inspected for set points, lockup, MAOP, and security were located at Spokane, Mica, Spangle, Rosalia, and St. John. The right-of-ways were inspected for signage, cathodic protection test sites, casings, and rectifier units.

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PART C – VIOLATION and CIVIL PENALTY INFORMATION

Information shown in Part C of this Pipeline Safety Violation Report relates to probable violations, proposed compliance orders, and proposed civil penalties

VIOLATION NUMBER #1

Section C1 – Description of Violation

Identify the regulation violated with the part, section, and most specific paragraph of Title 49, such as 192.309(b)(3)(ii). Enter only one regulation:

192.465 External Corrosion Control: Monitoring.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

Is this a violation of a condition in a Special Permit (Waiver)?

[x] No **[ ] Yes - identify permit and describe violation:** click here to enter

Describe the operator's conduct that violated the regulation:

The operator agreed that during the annual surveys taken in November for 2010 and 2011, the pipe-to-soil "off" potential difference for the A-Line was less than 100 mV with respect to the native potential.

Describe the evidence:

A-Line data at:
MP 110.2 the native potential is -0.698V and P/S for 2010 was -0.669V and for 2011 was -0.748V.
MP 110.8 the native potential is -0.708V and P/S for 2010 was -0.640V and for 2011 was -0.792V.

Person(s) interviewed (include each person's name, title, and an explanation of why this person's knowledge is important in establishing the violation):

Kurt Smith, Compliance Specialist and Rick Christman, Corrosion Specialist & NACE Level II. Rick assumed responsibilities in November 2011 as corrosion specialist for the Rosalia District and was aware of this data.

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Comments of person(s) interviewed regarding the violation (include names of any witnesses to the conversation):

Rick has been working to understand the history of the low CP values and analyzing seasonal effects on the data. I reviewed his data and agree that the native values need to be verified. GTN did not remediate the low C/P data from the August 2010 survey and began taking action August 2011 to identify the problem.

NATURE

Describe the nature of the violation in terms of: activities (conduct of activities such as inspections, tests, preparing procedures, maintenance, meetings, notifications, reports); or equipment/facilities (such as safety equipment not installed, missing, defective or inoperative); or records (identify the missing records or the records that were reviewed):

No records were available to review what remediation action GTN took after the August 2010 survey to correct the low Pipe-to-Soil reading at Mile Posts 110.2 and 110.8.

CIRCUMSTANCES

Describe who discovered the violation (operator, PHMSA, public) and the duration of the violation:

During the PHMSA inspection, GTN agreed that a potential violation was possible.

GRAVITY

Gravity relates to the seriousness of the probable violation, and includes consideration of whether it posed a significant threat to public safety and protection of the environment and where this threat occurred.

Enter the number of instances of the violation:

There were two instances identified for 2010 and 2011.

Non-IM Violation Only	1	[ ]	**The non-compliance affected the operator's emergency response capability**
	2	[X]	**The non-compliance had a minimal effect on pipeline integrity or safe operation of the pipeline and did not pose a significant threat to public safety or the environment**
	3	[ ]	**The non-compliance posed a significant threat to pipeline integrity or safe operation of the pipeline, or if left uncorrected would likely pose such a threat**
Select all that apply	4	[ ]	**The location of the noncompliance in items 2 and 3 (above) was in or affected a populated area, an HCA, an HCA "could affect" segment, a road or RR crossing,**

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		a plant/station, or similar area
	5	[ ] The non-compliance was a causal factor in, or contributed to the cause(s) of, a reportable accident/incident.
	6	[ ] The non-compliance contributed to increasing the severity of the consequences of a reportable accident/incident
	7	[ ] The non-compliance was a causal factor in a minor (non-reportable) release of product
	For selection 3 (above) describe the potential impact of this violation on public safety? click here to enter	
	For selection 3 (above) describe the potential impact of this violation on the environment? click here to enter	
IM Violation only	Enter the Area Finding & Risk Category data: • Area Finding: click here to enter • Risk Category (A-E): click here to enter	

Section C2 – Consequences of an Accident/Incident

Select all that apply	[X]	There was no accident/incident (continue to Section C3)
	[ ]	The event was reportable (§ 191.3 or § 195.50) regardless of whether it was reported by the operator.
	[ ]	One or more persons were evacuated. How many?: click here to enter
	[ ]	A cleanup of the resulting environmental damage was required.
	[ ]	One or more persons were injured and transported to a medical facility (regardless of whether as in-patient or out-patient). How many?: click here to enter
	[ ]	One or more fatalities. How many?: click here to enter
	[ ]	Other: Describe: click here to enter

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Section C3 – Additional Considerations

	[X]	**A civil penalty is not proposed for this violation (continue to Section C4).**

CULPABILITY

This civil penalty assessment consideration is based on how culpable - or blameworthy – the operator is for the non-compliance.

Culpability does not consider actions taken by the Operator after PHMSA has discovered the noncompliance.

Select one	[X]	**The operator failed to take any action to comply with a regulatory requirement that was clearly applicable to its facility.** Describe: No records were available to review what remediation action GTN took after the August 2010 survey to correct the low Pipe-to-Soil reading at Mile Posts 110.2 and 110.8.
	[ ]	**The operator made a minimal attempt to comply.** Describe: click here to enter
	[ ]	**The operator was cognizant of the regulatory requirement and took some steps to address the issue, but did not achieve compliance.** Describe: click here to enter
	[ ]	**The operator was cognizant of the regulatory requirement and took significant steps to address the issue, but had some degree of justification for not taking all practicable steps to achieve compliance at its facility.** Describe: click here to enter
	[ ]	**The operator was diligent in taking all practicable steps to comply but failed to achieve full compliance for reasons such as unforeseeable events/conditions that were partly or wholly outside its control; or the operator is a small or new operator in the process of building and strengthening its compliance program, or similar reasons.** Describe: click here to enter

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GOOD FAITH		
This civil penalty assessment consideration is based on the reasonableness of an operator's understanding of the cited regulatory requirement		
Select one	[X]	**GOOD FAITH exists if there is more than one reasonable interpretation as to how to implement the requirement at the facility and the operator had a credible belief that its approach was faithful to its duty to meet its obligation.** Describe: The operator stated that the data for the native values need to be verified.
	[ ]	**GOOD FAITH does not exist if there is guidance publicly available to operators on the subject and the operator did not act in accordance with the guidance, the operator failed to follow the only accepted industry practice, or if there is only one manner of implementing the requirement at the facility sufficient to accomplish the purpose of the requirement and the operator did otherwise.** Describe: click here to enter

Additional Comments applicable to civil penalty (Optional)	
(including other matters as justice may require and economic benefit gained from noncompliance)	
	Describe: click here to enter

Section C4 – Proposed Action

Select one	[ ]	**Civil penalty**	[ ]	**Civil penalty and compliance order**
	[ ]	**Compliance order**	[X]	**Other - describe:** The operator need to complete a comprehensive evaluation and remediate the less than 100 mV values for the difference in the pipe-to-soil "off" potential and its native potential for the A-Line near MP 110. The remediation should be completed and a field follow-up verification within six months.

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CPF click here to enter

PART D HISTORY of PRIOR OFFENSES (complete this section only if at least one of the violations in this case has a proposed civil penalty)				
(Prior offenses for the 5 year period prior to the estimated date of this Violation Report's Notice letter)				
Date of Final Order	**CPF #**	**What type of enforcement action(s) (CO, CP) are in the Final Order ?**	**Number of offenses in Final Order**	**Identify the regulation(s) violated (Part, Section, and specific Paragraph)**
click here	click here	click here	click here	click here
click here	click here	click here	click here	click here
click here	click here	click here	click here	click here
click here	click here	click here	click here	click here

Press TAB in the cell above to add rows

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CPF click here to enter

Inspector's signature & organization **Date: December 28, 2011**

Al Jones / UTC

PHMSA Region Director's signature **Date:**

(Rev. 4/2010)