01-27-12P12:27 RCVD

### POST INSPECTION MEMORANDUM

Inspector: Lex Vinsel/WUTC

Reviewed: Joe Subsits/WUTC

Peer Reviewed: RR

Follow-Up Enforcement: No Violation PCP\* PCO\* NOA

Director Approval\*

Date: January 11, 2012

**Operator Inspected:** 

Puget Sound Energy PO Box 90868 M/S PSE-12N Bellevue, WA 98007

**Unit Address:** 

PSE Sumas Gas Pipeline 1340 Thompson Lane Sumas, WA

**OPID: 22189** 

Region: Western

RECEIVED

APR 27 2012

State of Washington UTC Pipeline Safety Program

Unit Inspected: PSE Sumas Gas Pipeline

Unit Type: Interstate Natural Gas Transmission

**Inspection Type:** Standard

Record Location: Bellevue, WA

Inspection Dates: March 22, July 26-28, Aug 2-4, 2011

AFOD: 7

**SMART Activity Number:** 

IO1

Operator Contact: Michael Shores, Plant Manager

5days

Fax: (360) 998-2463 Phone: (360) 665-5523

Unit ID: 74999

sent electronic OQ form

Emergency: (800) 552-7171

**Unit Description:** 

PSE Sumas Interstate Pipeline facilities consist of (1) the border crossing facility, i.e., an interconnection with Westcoast Energy, Inc., at the international border between Canada and the United States, and (2) an 8-inch diameter pipeline located directly south of the Sumas gas meter station that crosses the Canada-United States border near or within the City of Sumas in Whatcom County, extending a distance of approximately 3.79 miles. The 8-inch diameter pipeline interconnects with the Sumas tie-in station at the 125-megawatt gas-fired Sumas cogeneration power plant owned by Sumas Cogeneration Company, L.P. (SCCLP).

**Facilities Inspected:** 

Unit inspection covered 3.79 miles of pipe from the border crossing to the Sumas Cogeneration plant.

**Persons Interviewed:** 

Darryl Hong	Compliance Program Manager	425-462-3911
Cheryl McGrath	Manager, Gas Compliance & Regulatory Audits	425-462-3207
Scott Sammons	Damage Prevention Coordinator	425-457-5816
Rick Elkin	Contract manager, Contractor  Management	253-395-6893
Steve Schueneman	Consulting Engineer	425-462-3971
Stephanie Silva	Consulting Engineer	425-462-3923
Dorthy C. Bracken	Customer Communications Manager	425-462-3206
Abigail J. Elliott	Public Relations Analyst	425-462-3795
Joe Graham	Senior Construction Manager	206-396-7413
Carol Wallace	Gas Operations Director	425-457-5807
Signe Lippert	Supervisor Maintenance Programs	206-766-6787
Gary Swanson	Program Coordinator	206-766-6811

### **Probable Violations/Concerns:**

None.

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.

### **Comments:**

First inspection of Interstate operator since status change.

### Attachments:

PHMSA Form 1 – Standard Inspection Report of a Gas Transmission Pipeline

PHMSA Form 13 - Pipeline Drug and Alcohol Questions

PHMSA Form 15 - OQ Field Inspection Protocol

PHMSA Form 16 – IMP Field Verification

Form R – Notes Field Inspection

Version Date: 5/5/08

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 Ins	spectio	on Memora	ndum		
		*/			Lex Vinsel, 1/11/2012			
Inspector/Submit Da	te: Lex Vinsel, 01/11/2012	Peer Review/Date:			17,			
			pproval/Date:	(	1	4/22/12		
750	POST INSPECTION	MEMOR	ANDUM (PIM)			m analysis and		
Name of Operator:	Puget Sound Energy				OPID #:	22189		
Name of Unit(s):	Sumas Interstate Transmission Pipeline				Unit #(s):	74999		
<b>Records Location:</b>	Bellevue WA				Activity #	WUTC #PG-110047		
Unit Type & Commo	odity: Natural Gas		V			1		
Inspection Type:	Standard		Inspection Date	2	2011	ıly 26-28, August 2-4,		
PHMSA Representa	tive(s): Lex Vinsel		AFO Days:	7	7			
Company System M	aps (copies for Region Files):							
Validate SMART Da	ata (components, miles, etc): Acqu	isition(s), S	ale or New Con	struct	ion (submi	t SMART update):		
Validate Additional	Requirements Resulting From Waiver(s)	or Special	Permit(s):					
			- anesage					
Summary:	ns were found during the inspection. The C	SM Manus	al was reviewed l	act ves	ar during a d	letailed O&M review		
No probable violation	is were round during the hispection.	XIVI IVIAIIU	ii was ieviewed i	iast you	ur during a c	ictatica Calvi Teview.		
Findings:	ns were found during the inspection.							
No probable violation	is were round during the hispection.							
						AL .		
z.								

Name of Operator: Pu OP ID No. (1) 22189	get Sound Ener	67	Unit ID No. (1)	74999			
HQ Address:		7 191	System/Unit Nam		ess: (1)	-	
PO Box 90868 M/S PSE-1	12N		1340 Thompson La	ane	Ni.		
Bellevue, WA 98007			Sumas, WA				
Co. Official:	Sue McLain,	Senior VP Operations	Activity Record I	D No.:	WUTC Docket	PG-110047	
Phone No.:	(425) 452-12	34	Phone No.:		(360) 766-5523		
Fax No.:			Fax No.:		(360) 988-2463		
Emergency Phone No.:	(800) 552-71		<b>Emergency Phone</b>	e No.:	(800) 552-717		
Persons Intervie	ewed		itle			hone No.	
Darryl Hong		Compliance Program Manager			425-462-3911		
Cheryl McGra	th	Manager, Gas Compliance & Regulatory Audits		udits	425-462-3207		
Scott Sammor	ıs	Damage Prevention Coordinator			425-457-5816		
Rick Elkin		Contract manager, Contractor Management		ent	253-395-6893		
Steve Schuenen	nan	Consulting Engineer			425-462-3971		
Stephanie Silv	/a	Consulting Engineer			425-462-3923		
Dorthy C. Brac	ken	Customer Communications Manager			425-462-3206		
Abigail J. Ellic	ott	Public Relations Analyst			425-462-3795		
Joe Graham		Senior Construction Manager			206-396-7413		
Carol Wallac	e	Gas Operations Director			425-457-5807		
Signe Lipper	t	Supervisor Maintenance Programs				5-766-6787	
Gary Swanson		Program Coordinator			206-766-6811		
PHMSA Representative	(s) (1) Lex V	insel		Inspection	on Date(s) (1)	March 22, July 26- 28, April 2-4, 2011	

### **Unit Description:**

Pipeline Description – The Sumas Pipeline facilities consist of (1) the border crossing facility, i.e., an interconnection with Westcoast Energy, Inc., at the international border between Canada and the United States, and (2) an 8-inch diameter pipeline located directly south of the Sumas gas meter station that crosses the Canada-United States border near or within the City of Sumas in Whatcom County, extending a distance of approximately 3.79 miles. The 8-inch diameter pipeline interconnects with the Sumas tie-in station at the 125-megawatt gas-fired Sumas cogeneration power plant owned by Sumas Cogeneration Company, L.P. (SCCLP).

Portion of Unit Inspected: (1)	
Unit inspection covered 3.79 miles of pipe from the border crossing to the Sumas Cogeneration plant.	

<sup>&</sup>lt;sup>1</sup> Information not required if included on page 1.

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.

	NPMS INFORMATION and UPDATE	Yes No
Did the operator submit their pipe	eline 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 a <a href="http://www.nrc.useg.mil/nrchp.html">http://www.nrc.useg.mil/nrchp.html</a> , 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 <a href="https://opsweb.phmsa.dot.gov">https://opsweb.phmsa.dot.gov</a> 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).	n x	
	191.15(a) 30-day follow-up written report (Form 7100-2) Submittal must be electronically to http://pipelinconlinereporting.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 a https://opsweb.phmsa.dot.gov (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	t	
	191.23 Reporting safety-related condition (SRCR)	х	
	191.25 Filing the SRCR within 5 days of determination, but not later than 10 days after discovery	х	
	191.27 Offshore pipeline condition reports – filed within 60 days after the inspections	х	
.605(d)	Instructions to enable operation and maintenance personnel to recognize potential	х	

Comments:	

### **49 CFR PART 192**

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

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

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

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

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

Comments:			
		*	
		,	

.605(a)		ABNORMAL OPERATING PROCEDURES	S	U N/A N/C
*	.605(c)(1)	Procedures for responding to, investigating, and correcting the cause of:		
l		(i) Unintended closure of valves or shut downs	x	
		(ii) Increase or decrease in pressure or flow rate outside of normal operating limits	х	
ł		(iii) Loss of communications	x	
		(iv) The operation of any safety device	x	
l		(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	х	
	.605(c)(3)	Notifying the responsible operating personnel when notice of an abnormal operation is received	х	
	.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	х	

Comments:		100	
	£.		

.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		

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

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

Comments:			
		- Company	

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

			The state of the s	The second secon
Comments:				
Comments.				

.605(a)		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U N/AN/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	х	
	(2) Provide notification to the public in the One Call area		x	
		(3) Provide means for receiving and recording notifications of pending excavations	х	
		(4) Provide notification of pending excavations to the members		
		(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	

			- Andrews	The state of the s
Comments:		¥I		
	a a			
			*	

.615		EMERGENCY PROCEDURES	S	U.	N/AN/C
	.615(a)(1)	Receiving, identifying, and classifying notices of events which require immediate response by the operator	х		
	.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	х		
		(iv) Natural disaster	x		

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.

	.615(a)(4)	Availability of personnel, equipment, instruments, tools, and material required at the scene of an emergency	x	
18	.615(a)(5)	Actions directed towards protecting people first, then property	х	
	.615(a)(6)	Emergency shutdown or pressure reduction to minimize hazards to life or property	х	
	.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	х	
	.615(b)(3)	Reviewing activities following emergencies to determine if the procedures were effective	x	7
	.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	c Awareness Program also in accordance with API RP 1162.			Siese in	
	.616(d)	The of	perator's program must specifically include provisions to educate the public, appropriate nment 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;	х			
		(3)	Physical indications of a possible release;	х			
		(4)	Steps to be taken for public safety in the event of a gas pipeline release; and	х			
		(5)	Procedures to report such an event (to the operator).	х			
	.616(e)		The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.  The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports gas.				
	.616(f)	The op					
	.616(g) Th		rogram conducted in English and any other languages commonly understood by a significant er of the population in the operator's area?	х			
ii 3	1.616(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.						

	1-9710		 The second second	
Comments:		The state of the s		

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.

Comment	:						
					CONTRACTOR OF THE PARTY OF THE	I suspensi I s	
.617	FAILURE INVESTIGATION PROCED			S	U	N/A	1/
	.617 Analyzing accidents and failures including laboratory analysis whand prevention of recurrence	nere appropriate t	o determine cause	х			_
Comment							_
Comment	•						
				TO STATE OF	E SECTION A	a mengerana	del
.605(a)	MAOP PROCEDURES			S	U	N/A	V.
	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 <b>MAOP</b> so that it is commensurate with the class loc	ation		X	ESCUTE .	2413631001	600
	MAOP cannot exceed the lowest of the following:						
*	(a)(1) Design pressure of the weakest element, Amdt. 192-103 pub	o. 06/09/06, eff. 0	7/10/06	Х	_	$\sqcup$	
	(a)(2) Test pressure divided by applicable factor			X			
*	(a)(3) The highest actual operating pressure to which the segment	of line was subject	cted during the 5 years				
	preceding the applicable date in second column, unless the segm	nent was tested a	ccording to .619(a)(2)				
	after the applicable date in the third column or the segment was 192-102 pub. 3/15/06, eff. 04/14/06. For gathering line related	uprated according	ig to subpart K. Amut				
	gathering line requirements, refer to Part 192 including this ar	nendment.	unnes and additional				
	gathering file requirements, roles to 1 mo 192 months and						
	Pipeline segment	Pressure date	Test date				
	Onshore gathering line that first became subject to this part (other than §	March 15,	5 years preceding				
	192.612) after April 13, 2006.	2006, or date line	applicable date in second	x			
	Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	becomes	column.				
	part before March 13, 2000.	subject to	Column	1			
	÷	this part,					
		whichever					
		is later.	1 1 1071				
	Offshore gathering lines.	July 1, 1976.	July 1, 1971.				
	All other pipelines.	July 1, 1970.	July 1, 1965.	1		1 1	

Refer to Attachment 1 for additional Alternative MAOP requirements. (Amdt. 192- 107, 73 FR 62147, October 17, 2008, eff. 11/17/2008).

(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

X

X

(a)(4) Maximum safe pressure determined by operator.

requirements, refer to Part 192 including this amendment.

(b) Overpressure protective devices must be installed if .619(a)(4) is applicable

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 Control of the included in this report. N/C - Not Checked

Commen	ts:				
.13(c)	PRESSURE TEST PROCEDURES	S	U	N/A N	I/C
	.503 Pressure testing	Х			_
Commen	ts:			8	
.13(c)	UPRATING PROCEDURES	S	U	N/A	1/0
2.7	.553 Uprating	х			_
Commen	ts:				
ile.					
.605(a)	ODORIZATION of GAS PROCEDURES	S	U	N/A	1/0
	Odorized gas in Class 3 or 4 locations (if applicable) – must be readily detectable by person with normal sense of smell at <sup>1/</sup> <sub>5</sub> of the LEL	х			
<u></u>	.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			
Commen	ts:				
	•				
.605(a)	TAPPING PIPELINES UNDER PRESSURE PROCEDURES	S	U	N/A	V/C
.005(a)	.627 Hot taps must be made by a qualified crew			Told Hotel	
	NDT testing is suggested prior to tapping the pipe. Reference API RP 2201 for Best Practices.	х			
.605(a)	PIPELINE PURGING PROCEDURES	S	U	N/A	N/C
.003(a)	.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.	х			
		х			
	(b) Lines containing gas must be properly purged				
Commen					_
Commen					

N/A - Not Applicable N/C - Not Checked Unless otherwise noted, all code references are to 49CFR Part 192. S-Satisfactory U-Unsatisfactory If an item is marked U, N/A, or N/C, an explanation must be included in this report.

*		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.				
	.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:			7	
		(1) Controller's authority and responsibility.				х
		(2) Controller's role when an abnormal operating condition is detected.				X
		(3) Controller's role during an emergency				х
		(4) A method of recording shift change responsibilities between controllers.				х
	.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.				х
		(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.				х
		(5) Establish and implement procedures for when a different controller assumes responsibility.				х
	.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.				х
		(2) Educating controllers and supervisors in fatigue mitigation strategies.				Х
		(3) Training of controllers and supervisors to recognize the effects of fatigue.				Х
	9	(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:			i i	
		(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.				х
		(3) Verifying the alarm set-point values and alarm descriptions once each year NTE 15 months.				х
		(4) Reviewing the alarm management plan at least once every calendar year NTE 15 months.				X
	3	(5) Monitoring the content and volume of activity being directed to and required of each controller once each year NTE 15 months.				х
		(6) Addressing deficiencies identified through implementation of 1-5 of this section.				х
	.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:	Carlos S			
		(1) Establishing communications between controllers, management and field personnel when implementing physical changes to the pipeline.				х
		(2) Requiring field personnel to contact the control room when emergency conditions exist and when field changes could affect control room operations.				Х

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 Control of the included in this report. N/C - Not Checked

*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
		(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.				Х
		(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:				х
		(1) Responding to abnormal operating conditions (AOCs).				X
		(2) Using a computerized simulator or other method for training controllers to recognize AOCs				х
		(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures.				х
		(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.				Х

Comme	ents:					
CRM	inspection	is	scheduled	for	2013	2

.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			TO SUPPLEMENTAL VALUE	
Comments:				

.605(b)	Т	RANSMISSION LINES	- PATROLLING & LEAKAGE SURV	EY PROCEDURES	S	U N/A	N/C
	.705(a)	Patrolling ROW condition	ons		х		
	(b) Maximum interval between patrols of lines:						
ij		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)	X		
		4	4/yr (4½ months)	4/yr (4½ months)	]		
V 90	.706	Leakage surveys – 1 yea	- 1 year/15 months				
		Leak detector equipmen	nt survey requirements for lines transporting un	-odorized gas			
		(a) Class 3 locations - 7½ months but at least twice each calendar year					
		(b) Class 4 locations -	41/2 months but at least 4 times each calendar	year	х		

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 Compared to 49CFR Part 192. N/C - Not Checked

		If an item is marked U, N/A, or N/C, an explanation must be included in this re	eport.			
Commen	ts:					
		St. of				
						9
.605(b)		LINE MARKER PROCEDURES	S	U	N/A	N/C
	.707	Line markers installed and labeled as required	X	Superior State		9200000
Commen	ts:					
.605(b)		RECORD KEEPING PROCEDURES	S	U	N/A	N/C
	.709	Records must be maintained:				
		(a) Renairs to the nine – life of system	x			

.605(b)		RECORD KEEPING PROCEDURES	S	U	N/AN/C
	.709	Records must be maintained:			
		(a) Repairs to the pipe – life of system	X		
		(b) Repairs to "other than pipe" – 5 years	х		
		(c) Operation (Sub L) and Maintenance (Sub M) patrols, surveys, tests - 5 years or until next one	х		

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				
		<ol> <li>Cut out a cylindrical piece of pipe and replace with pipe of ≥ design strength</li> </ol>	x			
		(2) Use of a reliable engineering method	х			
	.713(b)	Reduce operating pressure to a safe level during the repair	х			
		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:				3 41 7
		(1) The weld is not leaking	х			
		(2) The pressure is reduced to produce a stress that is 20% of SMYS or less	х			
		(3) Grinding is limited so that 1/8 inch of pipe weld remains	х			
		(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		<b>.</b> 0		
	.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	х			
		(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/AN/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		ii ii
		(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	х		
	(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)	х		

Comments:	A STATE OF THE STA	

.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.				
	(d)					
		(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	х			
	(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.	х			

Comments:	 Maria	

.605(b)		COMPRESSOR STATION PROCEDURES	S	U	N/AN/C
	.605(b)(6)	Maintenance procedures, including provisions for isolating units or sections of pipe and for purging before returning to service			Х
	.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			Х

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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:	х
		■ 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:	
No compressor in Sumas pipeline.	,

605(b)		PRESSURE LIMITING and R	EGULATING STATION PROCEDURES	S	U	N/A	N/C
.7	739(a)	Inspection and testing procedures for prostations and equipment (1 per yr/15 m	ressure limiting stations, relief devices, pressure regulating onths)	х			
		(1) In good mechanical condition		Х			
		(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed					
.7	739(a)	(3) Set to control or relieve at correct pressures consistent with .201(a), except for .739(b).					
7-20	(4) Properly installed and protected from dirt, liquids, other conditions that may prevent proper oper.						
.7	739(b)	For steel lines if MAOP is determined per .619(c) and the MAOP is 60 psi (414 kPa) gage or more			31 35		
		If MAOP produces hoop stress that	Then the pressure limit is:				
		Is greater than 72 percent of SMYS	MAOP plus 4 percent	x			
		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				
.7	743	Testing of Relief Devices					7.
.7	743	(a) Capacity must be consistent with .2	201(a) except for .739(b), and be determined 1 per yr/15 mo.	х			
.7	43	(b) If calculated, capacities must be compared; annual review and documentation are required.		х			
.74	43	(c) If insufficient capacity, new or ad	ditional devices must be installed to provide required capacity.	х			

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)	х	
	.745	(b)	Prompt remedial action required, or designate alternative valve.	х	

.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).	

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE
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Comments: No vaults in Sumas pipeline.			

.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	х	
		(b) Prevent welding or cutting on a pipeline containing a combustible mixture	х	
		(c) Post warning signs	х	

			0.000		
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.	х			
		(b) Retention of welding procedure – details and test	х			
	Note: Alter	rnate 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 (20 <sup>th</sup> 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.	х			
	.229	(a) To weld on compressor station piping and components, a welder must successfully complete a destructive test	х			
		(b) Welder must have used welding process within the preceding 6 months	X			
		(c) A welder qualified under .227(a) –			i.	
	.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).	х			
		(d) Welders qualified under .227(b) may not weld unless:				
		(1) Requalified within 1 year/15 months, or	х			
		(2) Within 71/2 months but at least twice per year had a production weld pass a qualifying test	х			
	.231	Welding operation must be protected from weather	х			
0	.233	Miter joints (consider pipe alignment)	х			
	.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)?	х			
	.241	(a) Visual inspection must be conducted by an individual qualified by appropriate training and experience to ensure:	х			

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.13(c)	V	VELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A N/C
.13(c)		(1) Compliance with the welding procedure	х		
		(2) Weld is acceptable in accordance with Section 9 of API 1104	х		
	(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:	х		
		(1) The nominal pipe diameter is less than 6 inches, or	x		(4
	2	(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	х		
	.241 (c)	Acceptability based on visual inspection or NDT is determined according to <b>Section 9 of API 1104</b> . If a girth weld is unacceptable under <b>Section 9</b> for a reason other than a crack, and if <b>Appendix A to API 1104</b> applies to the weld, the acceptability of the weld may be further determined under that appendix.	x		
		ternative acceptance criteria in API 1104 Appendix A are used, has the operator performed an ical Assessment (ECA)?		ψ.	
		epair and Removal of Weld Defects			
	(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.	х		
	, (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		
		ote: Sleeve Repairs – use low hydrogen rod (Best Practices –ref. API 1104 App. B, In Service Yelding)			

Comments:				
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.13(c)		NONDESTRUCTIVE TESTING PROCEDURES	S	Ü	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	х		
	(b)	Nondestructive testing of welds must be performed:			
		(1) In accordance with a written procedure, and	х		
		(2) By persons trained and qualified in the established procedures and with the test equipment used	х		
	(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		17	6
		(1) In Class 1 locations at least 10%	х		
		(2) In Class 2 locations at least 15%	X	6	
		(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%	х		
	(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/AN/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:	A CONTRACTOR OF THE CONTRACTOR	 e e	

*		JOINING of PIPELINE MATERIALS	S	U	N/A N/C
	.281	Joining of plastic pipe			
l		Type of plastic used			X
l		<ul> <li>Proper markings in accordance with §192.63</li> </ul>			Х
		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.			Х
	.285	Persons making joints with plastic pipe must be qualified			X
l	.287	Persons inspecting plastic joints must be qualified			X

Comments:
PSE does not use plastic pipe on this system.

.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	х		
.605(b)	· ·	Installation	х		
		Maintenance	х		
	.455	<ul> <li>(a) For pipelines installed after July 31, 1971, buried segments must be externally coated and</li> <li>(b) cathodically protected within one year after construction (see exceptions in code)</li> </ul>	X		
		(c) Aluminum may not be installed in a buried or submerged pipeline if exposed to an environment with a natural <b>pH</b> 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.	х		
	.463	Cathodic protection level according to Appendix D criteria	х		
	.465	(a) Pipe-to-soil monitoring (1 per yr/15 months) or short sections (10% per year, all in 10 years)	x		
	7	(b) Rectifier monitoring (6 per yr/2½ months)	x		

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 Control of the standard of the standar N/C - Not Checked

.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		(c) Interference bond monitoring (as required)	х			
		(d) Prompt remedial action to correct any deficiencies indicated by the monitoring	х			
	.465	(e) Electrical surveys (closely spaced pipe to soil) on bare/unprotected lines, cathodically protect active corrosion areas (1 per 3 years/39 months).	х			
	.467	Electrical isolation (include casings)	х			
	.469	Sufficient test stations to determine CP adequacy	X			
	.471	Test leads	X			
* *	.473	Interference currents	х			
	.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.	х			
		(c) Evaluate impact of configuration changes to existing systems. Final Rule Pub. 4/23/07, eff. 5/23/07.	х			
	.477	Internal corrosion control coupon (or other suit. Means) monitoring (2 per yr/7½ months)	х		:=:	
	.479	(a) Each exposed pipe must be cleaned and coated (see exceptions under .479(c))	х			
		Offshore splash zones and soil-to-air interfaces must be coated	х			
		(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	х			
	.481	(a) Atmospheric corrosion control monitoring (1 per 3 yrs/39 months onshore; 1 per yr/15 months offshore)	х			
	.481	(b) Special attention required at soil/air interfaces, thermal insulation, under disbonded coating, pipe supports, splash zones, deck penetrations, spans over water.	х			
	.481	(c) Protection must be provided if atmospheric corrosion is found (per §192.479).	х	_		
	.483	Replacement pipe must be coated and cathodically protected (see code for exceptions)	Х			
	.485	(a) Procedures to replace pipe or reduce the MAOP if general corrosion has reduced the wall thickness?	х			
		(b) Procedures to replace/repair pipe or reduce MAOP if localized corrosion has reduced wall thickness (unless reliable engineering repair method exists)?	х			
		(c) Procedures to use <b>Rstreng</b> or <b>B-31G</b> to determine remaining wall strength?	х			L
	.491	Corrosion control maps and record retention (pipeline service life or 5 yrs)	х			

Comments:		
Comments.		
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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 _X_	S	U	N/AN/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			х

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.605(b)	ī	UNDERWATER INSPECTION PROCEDURES – GULF of MEXICO and INLETS  If the operator has no pipelines in the Gulf, check here and skip this section _X_	S	Ü	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:	f - 1 30		х	
		(1) Promptly, within 24 hours, notify the National Response Center of the location of the pipeline?			х	
		(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?		ē	х	74.
	2	(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.			х	

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

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

Subparts	PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES
A - C	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 No Rectifiers in system		X	
.476	Systems designed to reduce internal corrosion Pipeline built and pressure tested August 1992.		X	
.479	Pipeline Components Exposed to the Atmosphere	X		
.612 (c) (2)	Pipelines exposed on seabed (Gulf of Mexico and Inlets): Not in Gulf of Mexico		X	
613(b), .703	Pipeline condition, unsatisfactory conditions, hazards, etc. None		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: .612 (c) (2) – Pipeline not located in the Gulf of Mexico and Inlets	4
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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 Countries of the marked U, N/A, or N/C, an explanation must be included in this report. N/C - Not Checked

	COMPRESSOR STATIONS INSPECTION (Field)	S	U	N/A	N/C
	(Note: Facilities may be "Grandfathered")	o	V	IVA	
	If not located on a platform check here and skip 192.167(c)			v	
63(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	$\vdash$
165(b)	Do the liquid separators have a manual means of removing liquids?		_	X	1
	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?	7 gr. 18 1	20,1000	X	
167(a)	ESD system must:		Ť	T v	
	- Discharge blowdown gas to a safe location			X	╁
	- Block and blowdown the gas in the station	_	-	Х	+
	- Shut down gas compressing equipment, gas fires, electrical facilities in compressor building and near			Х	_
	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:	7.3	T	X	SSM1
	- Outside the gas area of the station	-	+	$\frac{1}{x}$	+
	- Not more than 500 feet from the limits of the station	-	+-	$\frac{\lambda}{x}$	+
	- ESD switches near emergency exits?	+	-	A	+
.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:			Ιx	T
	■ The gas pressure equals MAOP plus 15%?	-	+	X	+
	An uncontrolled fire occurs on the platform?	12.20		I A	26.80
	- For compressor station in a building, when		<b>T</b>		
	An uncontrolled fire occurs in the building?	-	_	X	8
	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	300
.171(a)	Does the compressor station have adequate fire protection facilities? If fire pumps are used, they must not be affected by the FSD system.			X	_
(b)	Do the compressor station prime movers (other than electrical movers) have over-speed shutdown?	+	+	\rightarrow \rightarrow \chi \chi \chi \chi \chi \chi \chi \chi	-
(c)	Do the compressor units alarm or shutdown in the event of inadequate cooling or lubrication of the unit(s)?	+	4	- 1	+
(d)	Are the gas compressor units equipped to automatically stop fuel flow and vent the engine is stopped for any reason?	1	_	2	-
(e)	Are the mufflers equipped with vents to vent any trapped gas?	+	-	_	<
.173	Is each compressor station building adequately ventilated?	-	+	_	\ \
.457	Is all buried piping cathodically protected?	-	-	_	
.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?			2	X

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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	I/C
.615	Emergency Plan for the station on site?			Х	
.707	Markers	_		Х	-
.731	Overpressure protection – reliefs or shutdowns	1		X	_
.735	Are combustible materials in quantities exceeding normal daily usage, stored a safe distance from the compressor			X	
	Are aboveground oil or gasoline storage tanks protected in accordance with NFPA standard No. 30?	_		X	
.736	Gas detection – location			Х	

### Comments:

N/A - No compressor station on this pipeline system.

	CONVERSION TO SERVICE PERFORMANCE and RECORDS	S	U	N/AN/C
.14 (a)(2)	If no service conversion, check here and skip the section X  Visual inspection of right of way, aboveground and selected underground segments	grass.		x
(a)(3)	Correction of unsafe defects and conditions			х
(a)(4)	Pipeline testing in accordance with Subpart J		_	х
(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) Reviewed procedure	X		
191.12	Mechanical Fitting Failure Report (DOT Form PHMSA 7100.1-2) - if a fitting failure happened in the previous year.  No mechanical fittings failures on system.			X
191.15	Written incident reports; supplemental incident reports (DOT Form PHMSA F 7100.2) No incidents			X
191.17 (a)	Annual Report (DOT Form PHMSA F 7100.2-1) Extended to August 15, 2011.			X
191.23	Safety related condition reports No Safety Related Condition Reports			X
191.27	Offshore pipeline condition reports No offshore pipeline			X
192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports None			X

	CONSTRUCTION PERFORMANCE and RECORDS	S	UN	N/A N/
	Test Results to Qualify Welding Procedures	X		
.225	Welder Qualification Welder qualification performed at Local #32.	Х		
.227	Welder Qualification weider qualification per formed at Electrical 1/9/2010, requalification every 2 years.	X		
.241 (a)	Visual Weld Inspector Training/Experience Last qualification 11/8/2010, requalification every 2 years.	X		_
.243 (b)(2)	Nondestructive Technician Qualification Carlos Roderos - NDT Cert	-	$\vdash$	_
(c)	NDT procedures Gas Operating Procedures 2700.1200 Section 4	X	$\vdash$	
(f)	Total Number of Girth Welds - None		$\sqcup$	X
(f)	Number of Welds Inspected by NDT 100%	X		
(f)	Number of Welds Rejected- None		$\sqcup$	Х
(f)	Disposition of each Weld Rejected - None			X
.303	Construction Specifications	Х		
.325	Underground Clearance - None			X
.327	Amount, Location, Cover of each Size of Pipe Installed - None			Х

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	CONSTRUCTION PERFORMANCE and RECORDS	S	U N/A N/
.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 <b>No alternate MAOP</b>		Х
.455	Cathodic Protection Isolation Flanges	X	

	OPEI	RATIONS and MAINTENANCE PERFORMA	NCE and RECORDS	S	U	N/A	N/C
0		OUTER CONTINENTAL SHELF ONLY: Operator has i schematic] the specific point(s) at which operating responsibnear or on Outer Continental Shelf.	identified on pipeline(s) [or if subsea - on a illity transfers to a producing operator. Pipeline not			Х	
6		Customer Notification (Verification – 90 days – and Elements) No services				X	
603(b)	.605(a)	Maintenance (1 per vr/15 months) Introduction to					
603(b)	.605(c)	Abnormal Operations - None since last inspection.				X	Ļ
603(b)	.605(b)(3) Availability of construction records, maps, operating history to operating personnel PSE maps are		Х				
603(b)	.605(b)(8)	Pariodic review of personnel work - effectiveness of	normal O&M procedures	Х			┖
603(b)	.605(c)(4)	to the second of abnormal operation procedures None since last				Х	
100	.609	Class Location Study (If Applicable) NA for Sumas				X	L
709 503(b)	.612(b)	Gulf of Mexico/inlets: Periodic underwater inspection Gulf of Mexico.	ns based on the identified risk No pipeline in			Х	
	(14	Damage Prevention (Miscellaneous) PSE has a Dan	mage Prevention Plan	X			
709	.614	Location Specific Emergency Plan		Х			
603(b)	.615(b)(1)		ftmining	Х			
603(b)	.615(b)(2)	Emergency Procedure training, verify effectiveness o	C.H No emorganging	Х			t
603(b)	.615(b)(3)	Employee Emergency activity review, determine if p	rocedures were followed. No emergencies	X		-	+
603(b)	.615(c)	Liaison Program with Public Officials		A	E ATTEND	Education Co.	NA COL
03(b)	.616	Public Awareness Program  Documentation properly and adequately reflects imp					
		Program requirements - Stakeholder Audience iden method and frequency, supplemental enhancements mailing rosters, postage receipts, return receipts, au emergency responder, public officials, school super below:	dience contact documentation, etc. for intendents, program evaluations, etc.). See table	X	ŀ		
		API RP 1162 Baseline Recommende	nemission Line Operators)				
		Stakeholder Audience (Natural Gas Tran	Baseline Message Frequency (starting from effective date of Plan)				
	Resi	dents Along Right-of-Way and Places of gregation	2 years				
	Eme	gregation ergency Officials	Annual	7.			
		lic Officials	3 years				
		avator and Contractors	Annual Control				
	One	-Call Centers	As required of One-Call Center  Baseline Message Frequency				
	S	takeholder Audience (Gathering Line Operators)	2 Years	17.5			
	Res	idents and Places of Congregation	Annual			146	
		ergency Officials	3 years				
	Pub	lic Officials avators and Contractors	Annual				
	0	Call Centers	As required of One-Call Center		17-24		
	Def	er to APIRP 1162 for additional requirements, including	ng general program recommendations,				
	sup	plemental requirements, recordkeeping, program evalua	ation, etc.				
	616(a)	The program must be conducted in English and any	other languages commonly understood by a	. >	(		
*	.616(g)	significant number of the population in the operator  Effectiveness Review of operator's program. See C	r's area.	- 15	<		

N/C - Not Checked N/A - Not Applicable Unless otherwise noted, all code references are to 49CFR Part 192. S-Satisfactory U-Unsatisfactory If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	OPE	RATIONS and MAIN	NTENANCE PERFORMANCE and RECOR	RDS	S	U	N/A	N/C
.517		Pressure Testing Revi	ewed pressure test records		X			
.553(b)		Uprating - as prescribe	d by .555, or .557 as applicable. No uprating				X	
.709	.619 / .620	Maximum Allowable Operating Pressure (MAOP) If the pipeline is operating at the alternative MAOP under 192.620 (80% SMYS), refer to Attachment I for additional requirements. See  Comments Below						
.709	.625	Odorization of Gas - R	eviewed monthly records from 2008 to 2010.		X			
.709	.705	Patrolling (Refer to Ta	ble 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 (71/2 months)				
		4	4/yr (4½ months)	4/yr (4½ months)				
.709	.706	Leak Surveys (Refer t	o Table Below)		Х			
		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 sur	vey required for lines transporting un-odorized gas.					
.709	.731(a)	K	lief Devices (1 per yr/15 months) No compressor				X	
.709	.731(c)	Compressor Station En	nergency Shutdown (1 per yr/15 months) No comp	ressor station in system.			X	
.709	.736(c)	Compressor Stations system.	- Detection and Alarms (Performance Test) N	o compressor station in			Х	
.709	.739		Regulating Stations (1 per yr/15 months)		X			
.709	.743	Pressure Limiting and	Regulator Stations – Capacity (1 per yr/15 months)	No relief devices			Х	
.709	.745	Valve Maintenance (1	per yr/15 months)		Х			
.709	.749	Vault Maintenance (≥	200 cubic feet)(1 per yr/15 months) No vaults				Х	
.603(b)	.751	Prevention of Acciden	al Ignition (hot work permits) None				X	
.603(b)	.225(b)	Welding - Procedure	4900.1310/4900.1410		X			
.603(b)	.227/.229	Welding – Welder Qua	lification		X			
.603(b)	.243(b)(2)	NDT - NDT Personne	Qualification		Х			
.709	.243(f)	NDT Records (Pipelin	e Life)		Х			
.709	Repair: pipe	e (Pipeline Life); Other th	nan pipe (5 years)		Х			
.807(b)	Refer to PH	MSA Form # 15 to docur	nent review of operator's employee covered task rec	ords.				

### Comments:

.616(h) - November 2009 - Evaluation performed by Gilmore Research Group. Gilmore survey evaluated Customer Satisfaction and Customer awareness of gas system.

.619/.620 - MAOP determined by hydrostatic pressure test in August 1992.

		CORROSION CONTROL PERFORMANCE and RECORDS	S	U	N/A N/C
.453	CP proced	ures (system design, installation, operation, and maintenance) must be carried out by qualified personnel	Х		
.491	.491(a)	Maps or Records	Х		
.491	.459	Examination of Buried Pipe when Exposed None			Х
.491	.465(a)	Annual Pipe-to-soil Monitoring (1 per yr/15 months) or short sections (10 % per year, all in 10 years)	X		

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE
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		CORROSION CONTROL PERFORMANCE and RECORDS	S	U	N/AN/C
.491	.465(b)	Rectifier Monitoring (6 per yr/2½ months) None	315100	S. Droder de	Х
.491	.465(c)	Interference Bond Monitoring - Critical (6 per yr/21/2 months) None			X
.491	.465(c)	Interference Bond Monitoring - Non-critical (1 per yr/15 months) None			X
.491	.465(d)	Prompt Remedial Actions None during inspection period.			X
.491	.465(e)	Unprotected Pipeline Surveys, CP active corrosion areas (1 per 3 cal yr/39 months) None			X
.491	.467	Electrical Isolation (Including Casings)	X		
.491	.469	Test Stations – Sufficient Number	X		
.491	.471	Test Leads	X		
.491	.473	Interference Currents None			X
.491	.475(a)	Internal Corrosion; Corrosive Gas Investigation No corrosive gas			X
.491	.475(b)	Internal Corrosion; Internal Surface Inspection; Pipe Replacement None			X
.491	.476 (c)	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems None			х
.491	.477	Internal Corrosion Control Coupon Monitoring (2 per yr/7½ months) No corrosive gas			X
.491	.481	Atmospheric Corrosion Control Monitoring (1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore) Manual 4700.1600	Х		
.491	.483/.485	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions None			X

Comments:			

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### Attachment 1 Alternative Maximum Allowable Operating Pressure

For additional guidance refer to <a href="http://primis.phmsa.dot.gov/maop/faqs.htm">http://primis.phmsa.dot.gov/maop/faqs.htm</a>
For FAQs refer to <a href="http://primis.phmsa.dot.gov/maop/faqs.htm">http://primis.phmsa.dot.gov/maop/faqs.htm</a>

192.620	Alternative MAOP Procedures and Verifications	S	UN	I/AN	(/C
192.020	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)  0.80  0.67				
	3 0.56		5300	X	
620(a)	(1) Establish alternative MAOP commensurate with class location – no class 4	10.00	Sag.		
	(2) MAOP cannot exceed the lowest of the following:			x	
	(i) Design pressure of the weakest element	_		x	_
	(ii) Test pressure divided by applicable factor			х	
620(b)	(2) Pipeline constructed of steel pipe meeting additional requirements in §192.112.	-		х	_
	(3) SCADA system with remote monitoring and control	+	$\vdash$	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	Ī
	(7) 95% of girth welds have NDT		+	x	_
.620(c)	(1) PHMSA notified 180 days before operating at alternative MAOP		+	x	r
	(2) Senior Executive signatures and copy to PHMSA	+-		x	H
	(4) Strength test per §192.505 or certify previous strength test	+	-	x	H
	(6) Construction tasks treated as covered tasks for Operator Qualification	+	-	x	H
	(7) Records maintained for life of system	+	-	X	H
	(8) Class location change anomaly remediations	+	+-	x	t
.620(d)	(1) Threat matrix developed consistent with §192.917	_	+-	x	t
	(2) Recalculate the potential impact circle per §192.903 and implement public education per §192.616	28.	No. of the	A SERVI	鲤
	(3) Responding to an emergency in an HCA	784	<b>†</b>	x	T
	(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	7,51	a a a a a a a a a a a a a a a a a a a		
	(4) Protect the right-of-way:		1	T <sub>x</sub>	E I
	(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	-	+	+	+
	(iv) Use line-of-sight markers per §192.707	+	+-	X	+
	(v) Review damage prevention program in light of national consensus practices	$\dashv$	+	X	+
	(vi) ROW management plan to protect against excavation activities			X	
	(5) Control Internal Corrosion:		(A)		50
	(i) Program to monitor gas constituents		$\bot$	Х	

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192.620	Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
	(ii) Filter separators if needed			х	
	(iii) Gas Monitoring equipment used			X	
O.	(iv) Cleaning pigs, inhibitors, and sample accumulated liquids				
.620(d)	(v) Limit CO2, H2S, and water in the gas stream			х	
	(vi) Quarterly program review based on monitoring results			х	
	(6) (i) Control interference that can impact external corrosion			X	
	(ii) Survey to address interference currents and remedial actions			Х	
	(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%			х	
	(iii) Integrate internal inspection results with indirect assessment			х	
	(iv) Periodic assessments for HCAs			х	
1	(A-C) Close interval surveys, test stations at ½ mile intervals, and integrate results				
	(8) Cathodic Protection			х	
	(i) Complete remediations within 6 months of failed reading				
	(ii) Confirm restoration by a close interval survey			х	
	(iii) Cathodic protection system operational within 12 months of construction completion			х	
	(9) Baseline assessment of integrity			х	
	(i)(A) Geometry tool run within 6 months of service				
	(i)(B) High resolution MFL tool run within 3 years of service	2002.000		x	
	(ii) Geometry and MFL tool 2 years prior to raising pressure for existing lines			х	
	(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.			х	
# 1	(11) Repairs			х	
	(i)(A) Use of the most conservative calculation for anomaly remaining strength			i A	
	(B) Tool tolerances taken into consideration			х	
	(ii) Immediate repairs for:			х	
	(A) Dents meeting 309(b) criteria				
12	(B) Defects meeting immediate criteria in §192.933(d)			х	
	(C) Calculated failure pressure ratio less than 1.25 for .67 design factor			х	
	(D) Calculated failure pressure ratio less than 1.4 for .56 design factor			х	
	(iii) Repairs within 1 year for:			х	
	(A) Defects meeting 1 year criteria in 933(d)	n.V. 17-			
	(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			х	
	(D) Calculated failure pressure ratio less than 1.80 for .56 design factor			х	
	(iv) Evaluate defect growth rate for anomalies with > 1 year repair interval and set repair interval			х	
.620(e)	(1) Provide overpressure protection to a max of 104% MAOP			Х	
	(2) Procedure for establishing and maintaining set points for SCADA			Х	

	(iv) Evaluate defect growth rate for anomalies with > 1 year repair interval and set repair interval	х	
.620(e)	(1) Provide overpressure protection to a max of 104% MAOP	x	
100	(2) Procedure for establishing and maintaining set points for SCADA	X	
Commen	nts:		

N/A - Not Applicable

N/C - Not Checked

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

If an item is marked U, N/A, or N/C, an explanation must be included in this report. Comments: No alternative MAOP used

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
	SI GEN VERMAN VI CI	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
W 6000-96003 7702 18 1094947		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 <a href="http://phmsa.dot.gov/pipeline/regs/advisory-bulletin">http://phmsa.dot.gov/pipeline/regs/advisory-bulletin</a>

# PHMSA Pipeline Drug & Alcohol Questions

### Instructions

1. Use in conjunction with Unit inspections

2. Interview the primary operator contact for the Unit inspection you are conducting and enter their responses. Do not request the operator substance abuse expert to provide responses to these questions.

3. Send completed form to stanley.kastanas@dot.gov

Name of Operator	Puget Sound Energy		Op ID#	22189
Inspector	Lex Vinsel		Unit #	Sumas Gas Pipeline
Date of Inspection	7/27/2011	7.5		
Inspection Location City & State	Bellevue, WA			
Operator Employee Interviewed	1.Darryl Hong, Program Coordinator 2.Cheryl McGrath, Manager of Gas Compliance 3.Scott Sammons, Damage Prevention Coordinator		Phone #	425-462-3911
Position/Title				
Operator Designated Employer Represo (a.k.a. Substance Abuse Program Mana	entative (DER), ger)	Willie Adadill		
DER Phone # 425-462-3678				

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes	No	Does Not Know
.3, .101 .201, .245	1. Does the company have a plan for drug and alcohol testing of employees and contractors performing, or ready to perform, covered functions of operations, maintenance, and emergency response?	Х		
Comments				Г
.3 .105(c) .225(b)	2. Does the company perform random drug testing and reasonable suspicion drug and alcohol testing of employees performing covered functions? For random drug testing, enter the number of times per year employees are selected and the number of employees in each selection in Comments below.	X		,
Comments	Yes, all forms in back of drug and alcohol manual. 105 employees – 25% testing.	1		
.3 .105(b)	3. Does the company conduct post-accident/incident drug and alcohol testing for employees who have caused or contributed to the consequences of an accident/incident? Enter the position/title of the employee who would make the decision to conduct post-accident/incident testing in Comments below.	X		
Comments	Yes, DER of designee shall arrange.			
.113(c) .117(a)(4) .227(b)(2) .241	4. Does the company provide training for supervisors on the detection of potential drug abuse (minimum 60 minutes) and alcohol misuse (minimum 60 minutes)?	X		
Comments	Yes, Supervisor training performed on June 24, 2011			
.3 .113(b) .117(a)(4) .239(b)(11)	5. Does the company give covered employees an explanation of the drug & alcohol policies and distribute information about the Employee Assistance Program, including a hotline number? Provide details in Comments below.	X		
Comments	Yes, HR website has links to EAP programs.			

### **OPERATOR QUALIFICATION** FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	August 2-4, 2011
Name of Operator:	Puget Sound Energy
Operator ID (OPID):	22189
Inspection Location(s):	Sumas, WA
Supervisor(s) Contacted:	Roger Scheetz, Supervisor of Pressure Control
# Qualified Employees Observed:	3
# Qualified Contractors Observed:	0

Individual Observed	Title/Organization	Phone Number	Email Address		
John Macauley	Pressure Control Tech/PSE	(206)766-6766	john.macauley@pse.com		
Kevin Anson	Corrosion Control Tech/PSE	(425)766-1307	kevin.anson@pse.com		
David Strazdins	Customer Field Service Tech/PSE	(206)396-2061	dave.strazdins@pse.com		

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

PHMSA/State Representative	Region/State	Email Address
Lex Vinsel	Western/WA	lvinsel@utc.wa.gov
Joe Subsits	Western/WA	jsubsits@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.

	Inspection Results 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	et.
	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.

	Inspection Results an X in exactly one cell below)	Inspection Notes
X	No Issue Identified	
	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	
	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	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	1

### **Field Inspection Notes**

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

		Na	me/ID of Individual O	bserved	
		John Macauly	Macauly Kevin Anson	David Strazdins	
No	Task Name	Correct Performance (Y/N)	Correct Performance (Y/N)	Correct Performance (Y/N)	Comments
1	Stroke the valve PV-126	Y			4700.1600  Found 3 small leakers on instrument lines. Must shut down station to repair. Will repair during next shutdown.
2	Valve Exercise Valve #7932	Y			4515.1210 Exercised valve 1/8 of a turn OK
3	Pipe to Soil reads Valve #7932		Y		P/S -1.493 V
4	Pipe to soil reads Rock Road TS-066842	V V	Y		P/S -1.485 V
5	Check Odorant Levels in pipeline.			Y	ОК
6			6		
7					
8					
9					

## Operations and Maintenance Records Review

If performing an operations and maintenance records review in the course of your inspection,

### PHMSA (OQ) Field Inspection Form 15 (Rev. 4) May 17, 2007)

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.	Unsat.	Not Checked
		Х		
	Comments:			

# US Department of Transportation Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety – Form 16

### 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: <u>Puget Sound Energy, Sumas Gas Pipeline</u>

Op ID: <u>22189</u>

Perform Activity (denoted by mark)	Activity Number	Activity Description
	1A	In-Line Inspection
	1B	Hydrostatic Pressure Testing
X	1C	Direct Assessment Technologies
2	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
	4C	Field Inspection to Verify adequacy of the Cathodic Protection
		System
	4D	Field inspection for general system characteristics
	attachment	Anomaly Evaluation Report
	attachment	Anomaly Repair Report

### **Gas IMP Field Verification Inspection Form**

Name of Operator: Puget Sound Energy

Headquarters Address:

Puget Sound Energy PO Box 90868 M/S PSE-12N Bellevue, WA 98009-0868

Company Official: Sue McLain Senior Vice President, Operations

Phone Number: (425) 462-3696 Fax Number: (425) 462-3770

Operator ID: 22189

Persons Interviewed	Title	Phone No.	E-Mail	
Darryl Hong	Primary Contact			
Cheryl McGrath	Manager Gas Compliance	425-462-3207	Cheryl.mcgrath@pse.com	
Scott Sammons	Damage Prevention Coordinator	425-457-5816	Scott.sammons@pse.com	
Steve Schueneman	Consulting Engineer Gas System Engineer	425-462-3971	Steven.schueneman@pse.com	
Stephanie Silva	Consulting Engineer Gas For Standards			

OPS/State Representative(s): Lex Vinsel, Patti Johnson, Dave Cullom

Date(s) of Inspection: July 26-28, 2011

Inspector Signature: Lex Vinsel/WUTC

Date: 1/11/2012

**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.)]

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.]

Sun	nm	ar	v:

No violations were found

Findings: None

### **Key Documents Reviewed:**

Document Title	Document No.	Rev. No	Date
Integrity Management Program Standards	7500.1000	2010	7/26/2011
Investigating Failures	2575.1900		7/26/2011
MAOP Determination	2525.1100	3/01/2011	7/26/2011
High Consequence Areas Section 3.3	7500.2000	10/01/2010	7/26/2011
External Corrosion Direct Assessment (ECDA)	7500.4100		

### Part 1 - Performance of Integrity Assessments

1A. In-Line Inspection	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that Operator's O&M and IMP procedural	X			Do not use ILI. PSE uses ECDA. See 7500.4100
requirements (e.g. launching/receiving tools) for performance of ILI were followed.	Α			7300.4100
Verify Operator's ILI procedural requirements were for	llowed (e a	oneration of t	ran	
for launching and receiving of pig, operational control	of flow), as a	appropriate.	шр	
Verify ILI tool systems and calibration checks before r	un were perf	formed to ensu	ıre	PSE uses the 4 steps in ECDA;
tool was operating correctly prior to assessment being p	performed, a	s appropriate.		1.Pre assessment
Verify ILI complied with Operator's procedural require				2.Indirect assessment
successful assessment (e.g. speed of travel within limits	s, adequate t	ransducer		3.Direct assessment
coverage), as appropriate.				4.Post Assessment
Document ILI Tool Vendor and Tool type (e.g. MFL, I		). Document		
other pertinent information about Vendor and Tool, as	appropriate		Colomb	8
Verify that Operator's personnel have access to applica	ble procedu	res for prepari	ng,	
running and monitoring the pipeline for ILI tools include			nts	
(e.g.: tool speeds, pipe cleanliness, operation of tool se	nsors, and n	Li field		
calibration requirements), as appropriate.				[Note: Add location specific
Other:				information, as appropriate.]
1D. Hadron M. Docesson Treating	Satisfactory	Unsatisfactory	N/C	Notes: PSE has not conducted any
1B. Hydrostatic Pressure Testing  Verify that hydrostatic pressure tests complied with		Olisatisfactory	IVC	hydrostatic pressure tests.
Part 192 Subpart J requirements.	X			The operator does not use this as a
Review documentation of Hydrostatic Pressure Test pa	rameters and	l results. Ver	ifv	method.
test was performed without leakage and in compliance	with Part 19	2 Subpart J		
requirements.		· · · · · · · · · · · · · · · · · · ·		
Review test procedures and records and verify test acce	ptability and	d validity.		
Review determination of the cause of hydrostatic test fa				
Document Hydrostatic Pressure Test Vendor and equip				
Verify that the baseline assessment is conducted in a m				
	anno mat n	imimizes		
				, at
environmental and safety risks (reference §192.919(e) Other:				,,
environmental and safety risks (reference §192.919(e)				
environmental and safety risks (reference §192.919(e) of Other:  1C. Direct Assessment Technologies			N/C	Notes:
environmental and safety risks (reference §192.919(e) of Other:  1C. Direct Assessment Technologies  Verify that application of "Direct Assessment"	Satisfactory	-01)	N/C	Reviewed ECDA for HCA segment
environmental and safety risks (reference §192.919(e) of Other:  1C. Direct Assessment Technologies  Verify that application of "Direct Assessment Technology" complied with Part 192.923	Satisfactory	Unsatisfactory	N/C	
environmental and safety risks (reference §192.919(e) of Other:  1C. Direct Assessment Technologies  Verify that application of "Direct Assessment Technology" complied with Part 192.923  Review documentation of Operator's application of "D	Satisfactory  X irect Assess:	Unsatisfactory ment	N/C	Reviewed ECDA for HCA segment
environmental and safety risks (reference §192.919(e) of Other:  1C. Direct Assessment Technologies  Verify that application of "Direct Assessment Technology" complied with Part 192.923  Review documentation of Operator's application of "D Technology", if available. Verify compliance with Part	Satisfactory  X irect Assess:	Unsatisfactory ment	N/C	Reviewed ECDA for HCA segment
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### 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.	L	l		
Witness anomaly remediation and verify documentation				
Exposed Pipe Reports, Maintenance Report, any Data A			fy	
compliance with Operator's O&M Manual and Part 192	2 requirement	nts.		
v. '6 d . 0				· ·
Verify that Operator's procedures were followed in loc	ating and ex	posing the		
anomaly (e.g. any required pressure reductions, line loc				
approximate location of anomaly for excavation, excav	ation, coath	ig removar).		
Verify that procedures were followed in measuring the	anomaly de	termining the		
severity of the anomaly, and determining remaining str	ength of the	nine Review	the	
class location factor and failure pressure ratio used by				Cathodic Protection readings of pipe to
of anomaly.	sperator in t		Ι	soil at dig site (if available):
of unomary.				On Potential:mV
Verify that Operator's personnel have access to and known	owledge of a	applicable		Off Potential:mV
procedures.	J			1
r				[Note: Add location specific information
Other:				and note whether CP readings were from
				the surface or from the pipe following
				exposure, as appropriate.]
2B. Remediation - Implementation	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that the operator has adequately implemented				r°
its remediation process and procedures to effectively				3
remediate conditions identified through integrity				
assessments or information analysis.  If documentation is available, verify that repairs were of	ampleted in	nagardanaa y	uith.	
the operator's prioritized schedule and within the time	frames allow	ved in	VILII	
\$192.933(d).	ii aiiios aiiov	ved III		
§192.933(u).				
Review any documentation for this inspection site for a	n immediate	e repair condi	tion	
(§192.933(d)(1)) where operating pressure was reduced				
shutdown. Verify for an immediate repair condition th	at temporary	operating		
pressure was determined in accordance with the require	ements in §1	92.933(a) or,	if	
not applicable, the operator should provide an engineer	ing basis jus	stifying the		0
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 Oper	ator's O&M	Manual, as		
appropriate. If welding is performed, verify a qualified	welding pr	ocedure and	1	
qualified welders are used to perform repairs. If composition the description of	osite repair i	nethods are u	sea,	Cathodic Protection readings of pipe to
verify that a method approved by the Operator is used, qualified personnel perform the repair.	procedures	are followed,	anu	soil at dig site (if available):
quantied personner perform the repair.				On Potential:mV
Review CP readings at anomaly dig site, if possible. (S	See Part 4 of	fthis form –	-12	Off Potential:mV
"Field Inspection to Verify adequacy of the Cathodic P	rotection Sy	stem", as		10 contracts (10
appropriate.		**************************************		[Note: Add location specific information
app. op. and				and note whether CP readings were from
Other:				the surface or from the pipe following
a store to				exposure, as appropriate.]

### Part 3 - Preventive and Mitigative Actions

24 DCM Massaures for Third Porty Domogo	Satisfactory	Unsatisfactory	N/C	Notes:
3A. P&M Measures for Third Party Damage  Identify additional measures evaluated for the HCA	Satisfactory	Olisatisfactory	IV/C	ivotes.
section of the pipeline and facilities.	3			
Verify that P & M measures regarding threats due to the implemented: [§192.915(c), §192.935(b)(1)(iv)]:	ird party dar	nage are being	g	
Confirm the use of qualified personnel for marking, loc of known excavation work, as appropriate.	ating, and d	irect supervisi	ion	
Confirm the use of qualified personnel for monitoring of covered pipeline segments by pipeline personnel, as app		ns conducted of	on	
Other:				
				·
4				[Note: Add location specific information, as appropriate.]
3B. Installed Automatic Shut-off Valves (Protocol				Notes:
H.07)	Satisfactory	Unsatisfactory	N/C	Notes.
Verify additional preventive and mitigative actions				
implemented by Operator.				a a
Document that additional measures evaluated by the op such as, installing Automatic Shut-off Valves or Remo computerized monitoring and leak detection systems, repipe of heavier wall thickness, providing additional trainesponse procedures, conducting drills with local emerg implementing additional inspection and maintenance proverify that the operator has a process to decide if automate control valves represent an efficient means of act potentially affected high consequence areas. [§192.935]	te Control Neplacing pip- ning to pers gency respon- ograms, as a natic shut-of Iding protec	Valves, installing segments with connel on the conders and appropriate or walves or		
Verify operation of installed remote control valve by re inspection/remote control records for partially opening appropriate.				
Other:		S.		
The second second				
		417777, 91777, 1707		[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.	Х			HCA Standard 7500.2000.
Utilize NPMS and Operator maps, as appropriate.  Verify that the operator's integrity management program		ccurate and		PSE uses method 2 for HCA determination.
updated system maps or other suitably detailed means of	locumenting	the pipeline		AVVA ARMINIATION
segment locations that are located in high consequence				Confirmed baseball field as HCA.
[§192.905(a)]				
Review the operator's applicable procedures and forms	used to doc	ument new	l by	
information from one-calls, surveys, aerial & ground pa field personnel to communicate new developments that	may impact	mg completed t high	ιυy	
consequence areas or that may create new high consequence	ience areas t	to IM personn	el,	
as appropriate. [§192.905(c)]				
2 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	. to	that navy IIC	Λ α	
Review the operator's applicable procedures and form and class location changes are being identified through	it's continu	ing surveillan	ce	[Note: Add location specific information,
program as required by §192.613 and §192.905.	o continu	oai roman		as appropriate.]
	Satisfactors	Unsatisfactory	N/C	Notes:
4B. Field Inspection for Verification of Anomaly Digs Verify repair areas, ILI verification sites, etc.	Satisfactory	Olisatistactory	N/C	110165.
Document the anomaly dig sites observed and reviewed	l as part of t	his field activ	ity	[Note: Add location specific information,
and the actions taken by the operator.	(F)		ıδ	as appropriate.]
	e antaren (1816-186)		New Part of W	
4C. Field Inspection to Verify adequacy of the	Cation	I Imagetic for a to	N/C	Notes:
Cathodic Protection System	Satisfactory	Unsatisfactory	N/C	
In case of hydrostatic pressure testing, Cathodic				
Protection (CP) systems must be evaluated for general				
The operator should review the CP system performance	in coniunc	tion with a		
hydrostatic pressure test to ensure the integrity assessm	ent addresse	ed applicable		
threats to the integrity of the pipeline. Has the operator	reviewed tl	ne CP system		
performance in conjunction with the hydrostatic pressu				Cathodic Protection readings of pipe to
Review records of CP readings from CIS and/or annual code requirements are being met, if available.	survey to e	nsure minimu	ım	soil at dig site (if available):
code requirements are being met, it available.				On Potential:mV
	240 W	9 (19 (19 (19 (19 (19 (19 (19 (19 (19 (1		Off Potential:mV
Review results of random field CP readings performed				Note: Add logation specific information
minimum code requirements are being met, if possible checks during this activity and ensure rectifiers are ope	Pertorm ra	indom rectifie	r le	[Note: Add location specific information and note whether CP readings were from
checks during this activity and ensure rectifiers are ope	rating corre	cny, ii possio	10.	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		20		
estimation of the effectiveness of the operator's IMP				9
implementation.		ım aada	L	
Evaluate condition of the ROW of inspection site to en requirements are being met, as appropriate.	sure minimi	mi code		
Comment on Operator's apparent commitment to the in	ntegrity and	safe operation	ı of	
their system, as appropriate.				
Check ROW for pipeline markers in line-of-sight and I	Emergency o	call-in number	on	
marker posts.				
Other:				

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

Pipeline Syste	m 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:
	eported Information
ILI Technology (e.g., Vendor, Tools):	
Anomaly Type (e.g., Mechanical, Metal Loss)	:
Is anomaly in a segment that can affect an HC	
Date of Tool Run (MM/DD/YY):	Date of Inspection Report (MM/DD/YY):
Date of "Discovery of Anomaly" (MM/DD/Y	
Type of "Condition" (e.g.; Immediate; 60-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):
	Site Information Summary
Date of Anomaly Dig (MM/DD/YY):	y
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 fo	ound (ft):
	anical Damage Anomaly
Damage Type (e.g., original construction, plai	
	Vidth (in): Depth (in):
Near a weld? (Yes / No):	
Gouge or metal loss associated with dent? (Ye	es / No): Are multiple dents present? (Yes / No):
Did operator perform additional NDE to evalu	
Cracks associated with dent? (Yes / No):	
For Corro	sion Metal Loss Anomaly
Anomaly Type (e.g., pitting, general):	· ·
	Vidth (in): Max. Depth (in):
Remaining minimum wall thickness (in):	Maximum % Wall Loss measurement(%):
Safe pressure calculation (psi), as appropriate:	
	er Types" of Anomalies
Describe anomaly (e.g., dent with metal loss,	
	Vidth (in): Max. Depth (in):
Other Information, as appropriate:	
Did operator perform additional NDE to evalu	nate presence of cracks? (Yes / No):
Cracks present? (Yes / No):	1
Transfer Variable 2 1/2/2	

## 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
i ii Cr teadings taken, kecord. On rotential.
[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):
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[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):

# OPTIONAL FIELD DATA COLLECTION FORM FOR INTERSTATE OPERATORS

# NOTES-FIELD INSPECTION

Company: Puget Sound Energy

Date(s): August 4, 2011

Unit: Sumas Gas Pipeline

				F	Field Readings	sgu			
Line & Location		Line	CP	CP Volts	Rectifier	ifier	Press	Pressures	Remarks
	Size	In.	P/S	Casing	Volts	Amps	Set	Actual	
Sumas PV-126								g:	PSE #4700.1600
Run #1								456.5	Pressure Valve operation is
Run #2		*						454.0	tested by stroking the valve.
Sumas Valve			-1.493 V		TX.				PSE #4515.1210
#7932									Exercised valve an eighth of a
Pipe to Soil Reads									tum.
Test Site			-1.485 V	1					
#TS-066842									
Sumas at Rock									
Road									47
Check Odorant									Gas in Air 0.337%
Levels in pipeline								1	A STATE OF THE PROPERTY OF T
at OT-0204									
	2								