SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

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

Comments: **Operator evaluates for SCC when pipeline is exposed.**

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

Comments: **No SCC has been found on transmission or plant pipelines.**

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

Comments: **Yes.**

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

Comments: **Yes.**

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

Comments: **Yes, the operator is considering evaluating the 14" pipeline for SCC.**

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

Comments: **Yes.**

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

Comments: **Yes.**

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

Comments: **SCC has not been identified via exposed pipe and in-line inspections.**

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

Comments: **Yes, it's part of the risk assessment tool**

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

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

Comments: **N/A**

High pH SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
  - Age $\geq$ 10 years
  - Operating stress > 60% SMYS

- Pipe temperature >100 deg. F (typically < 20 miles d/s of compression)
- Damaged pipe coating
- Soil Characteristics
  - Soil pH range: 8.5 to 11
  - Alkaline carbonate/bicarbonate solution in the soil
  - Elevated soil temperature contributing to elevated pipe temperature
- Polarized cathodic potential range: -600 to -750 mV, $Cu/CuSO_4$

Low or Near-Neutral pH SCC Potential Risk Indicators

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

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

OPTIONAL FIELD DATA COLLECTION FORM FOR INTRASTATE INSPECTORS

NOTES-FIELD INSPECTION

Company: Puget Sound Energy **Date(s):** June 8 – 11, 2009

Unit: Jackson Prairie Gas Storage

Field Readings									
Line & Location	Line		CP Volts		Rectifier		Pressures		Remarks
	Size	In.	P/S	Casing	Volts	Amps	Set	Actual	
Rectifier # 4					15.7	32.3			Location: South End of Plant Setting: Course #1, Fine #6
Rectifier #12					12.6	14.3			Location: West End of Plant Setting: C1, F4
Rectifier #13					11.8	22.3			Location: South End of Plant Setting: C1, F4
Rectifier #15					7.6	17.8			Location: North End of Plant Setting: C1, F5
Rectifier #16					7.7	8.7			Diodes are damaged and need replacing. Location: North End of Plant Setting: C2, F5
Test Site #13	8”		-1.256						Need insulator between Piping and support post
Test Site #14	10”		-1.669						
Test Site #16	16”		-1.610						
Test Site #17	20”		-1.084						At Williams Pipeline-Transfer
	20”		-1.288						At PSE-Jackson Prairie Pipe
Test Site #20	16”		-1.333						Corrosion cell at ground-to-air interface
Well No. 906			-1.564						

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Field Readings									
Line & Location	Line		CP Volts		Rectifier		Pressures		Remarks
	Size	In.	P/S	Casing	Volts	Amps	Set	Actual	
									Page 2 of 2
Olympic Pipeline Xing MP 190	24" 20" 16" 14"		-1.429 -1.428 -1.428 -1.427						
"G" Casing	10"		-1.637	-0.421					Good CP separation between pipeline and casing
Inside secured Plant Facility at:									
(a)West end of Plant	24"		-1.44						
(b) NE corner of Plant	24"		-1.45						
(c)East Cooler #1			-0.917						
(d)Triethylene Glycol (TEG) Plant Piping			-0.576						The Glycol lines are not jurisdictional.
(e)Fuel Line to TEG Regen#1	2"		-0.955						
(f)Fuel Line to TEG Regen#1	2"		-1.074						