EPCO, INC.

June 29, 2009

R.M Seeley, Director
Southwest Region
Pipeline and Hazardous
Materials Safety Administration
8701 South Gessner Road, Suite 1110
Houston, TX 77074

Re: Notice of Amendment dated January 7, 2009 (the "Notice")
EPCO, Inc.
CPF No. 4-2009-5001M

Dear Mr. Seeley:

EPCO, Inc. (EPCO) submits the following response to the Notice. References are to the numbered items in the Notice and regulatory provisions cited therein. By submitting this response, EPCO expresses no view of and shall not be deemed to have made any admission as to the validity or enforceability of the regulatory interpretations upon which the Notice was based.

In a submittal dated February 9, 2009, EPCO requested an extension of time until June 30 to address items 1 and 6 and until August 31 to address items 3, 4, and 5. PHMSA granted the requested time extensions in a letter date February 13, 2009. In accordance with the submittal dated February 9, this submittal addresses items 1 and 6.

Item 1 – 49 CFR §195.452 (c)(1), (f) (5) and (j) (5)

The Assessment Method Selection Procedure has been revised to identify the approved assessment methods for assessing specific threats (e.g. metal loss; deformation; cracking; long seam failure susceptibility) and is enclosed.

Item 2 – 49 CFR §195.452 (f)(4) and (h)(4)

The Operating Pressure Procedure has been revised to determine the temporary operating pressure for an immediate repair condition in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 and was enclosed in the submittal dated February 9, 2009.

Item 3 – 49 CFR §195.452 (f) (3) and (g)

The development of a procedure that provides firm process language to update the new and soon to be implemented risk model on a frequent and regular basis is being developed and has not been incorporated. The IMP Change Management process will be completed by August 31, 2009.

Item 4 – 49 CFR §195.452 (f)(6), (i)(1), and (i)(2)

The Information Analysis–Line Pipe and the Information Analysis–Facilities procedures are being modified to improve the documentation of the application of threats which are identified in the risk model(s) as well as provide guidance for risk based prioritization of P&MM projects but have not been incorporated. The IMP Change Management process will be completed by August 31, 2009.

Items 5 – 49 CFR §195.452 (f)(5), (j)(1), and (j)(2)

The Information Analysis–Line Pipe procedure is being modified to address the performance of periodic evaluations, to assure pipeline integrity, as frequently as needed and based upon risk factors specific to the pipeline segment including those specified in 195.452(e). The IMP Change Management process will be completed by August 31, 2009.

Item 6 – 49 CFR §195.452 (f)(7) and (k)

The Measure IMP Effectiveness Procedure has been revised to provide additional guidance regarding the documentation of consolidated findings resulting from the process of evaluating the IMP effectiveness measures and is enclosed.

EPCO appreciates having the opportunity to respond to the Notice and will look forward to continuing to work with the Pipeline and Hazardous Materials Safety Administration to assure the safe operation of our pipelines. Please let me know if you have any questions.

Sincerely yours,

Kevin Bodenhamer
Vice President

Enclosure

cc: Phu Phan w/ encls.

1.0 PURPOSE:

The purpose of this procedure is to identify the applicable integrity threats and determine the method(s) required to assess the integrity of the line pipe.

2.0 PROCEDURE:

2.1 DATA GATHERING

The Pipeline Integrity Engineer shall ensure the following information is gathered in order to perform the assessment method selection.

2.1.1 The assessment segments in the Baseline Assessment Plan.

- 2.1.1.1 Assessment ID
- 2.1.1.2 Line ID
- 2.1.1.3 Segment Description

2.1.2 The line pipe characteristics listed in PODS, alignment sheets, original construction records or prior assessment method selection documentation.

- 2.1.2.1 Identify if any line pipe material other than carbon steel is present in the assessment segment.
- 2.1.2.2 Identify all the line pipe diameter(s) present in the assessment segment
- 2.1.2.3 Identify if any Low Frequency ERW or Lap welded pipe is present in the assessment segment.
  - 2.1.2.3.1 If longitudinal seam type is unknown, refer to ASME publication, "The History of Line Pipe Manufacturing in North America", the manufacturer and date of manufacturing of the line pipe to determine if it is not Low Frequency ERW or Lap welded pipe.
  - 2.1.2.3.2 If no conclusion can be derived from the method above, assume that the unknown pipe constructed prior to 1970 is pre-1970 Low Frequency ERW or Lap welded pipe
- 2.1.2.4 Identify if any coating type other than Fusion Bonded Epoxy is present on the pipe body within the assessment segment

2.1.3 The operating conditions of the assessment segment as obtained from PODS, Pipeline Control or Operations.

- 2.1.3.1 MOP for the assessment segment.
- 2.1.3.2 Determine the highest MOP % SMYS for the assessment segment.

2.1.3.3 Identify if the normal operating temperature exceeds 100°F.as obtained from Pipeline Control or Operations

2.1.4 If a pressure cycle analysis has been performed on the assessment segment, identify the results of the most recent pressure cycle analysis.

2.1.5 The line pipe failure and hydrostatic testing failure history for the assessment segment as obtained from PODS or the most recent hydrostatic test documentation

2.1.5.1 Identify the number of in-service or hydrostatic testing failures and its cause of failure present in this assessment segment.

2.1.5.2 Identify if a hydrotest was performed to a maximum hydrotest pressure greater than 1.5 times the MOP

2.1.6 Obtain the results and recommendations from the most recent Information Analysis for the assessment segment.

2.1.6.1 Identify if the Information Analysis determined the condition of SCC to exist on the assessment segment.

2.1.6.2 Identify any threat assessment recommendations from section 2.3 of the previous Information Analysis

2.1.7 Determine if any crack indications (SCC or longitudinal seam cracks) have been found on this assessment segment. Data sources for this determination include but are not limited to in-service failure history, hydrostatic testing failure history, and applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may also be considered.

2.2 EVALUATE FOR THREAT SUSCEPTIBILITY

2.2.1 The Pipeline Integrity Engineer shall evaluate the assessment segment to identify its susceptibility to Longitudinal Seam Failure.

2.2.1.1 The method used to determine each assessment segment's susceptibility to Seam failure is described in the report TTO Number 5 Integrity Management Program Delivery Order DTRS56-02-D-70036 "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation" made available by Department of Transportation Research and Special Programs Administration Office of Pipeline Safety.

2.2.1.2 Information available in the paper by John F. Kiefner titled "Dealing With Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe With Respect To HCA-Related Integrity Assessment", paper No. ETCE2002/PIPE-29029 may also be considered.

2.2.1.3 Data from ASME publication, "The History of Line Pipe Manufacturing in North America" may be used to determine if

ERW line pipe was manufactured with a high frequency mill process.

2.2.1.4 Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment.

2.2.1.5 Failures of longitudinal seam welds during the original construction hydrostatic test are classified as manufacturing related defects and are not fatigue related failures.

2.2.2 The Pipeline Integrity Engineer shall evaluate the assessment segment to identify its susceptibility to Stress Corrosion Cracking (SCC) failure.

2.2.2.1 The method used to determine each assessment segment's susceptibility to high pH SCC failure is described in ASME B31.8S Appendix A3.

2.2.2.2 For line pipe that has any coating type other than Fusion Bonded Epoxy that operate at temperatures greater than 100˚F and with MOP greater than 60% SMYS, additional data shall be gathered as specified in ASME B31.8S Appendix A3.

2.2.2.2.1 The additional data to be gathered include age of pipe and distance from a pump station. Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may also be considered

2.2.2.3 The following information may be considered to determine each assessment segment's susceptibility to near neutral pH SCC failure.

2.2.2.3.1 Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment. .

2.2.2.3.2 If "systemic" near neutral pH SCC is found during in-ditch examinations, then the assessment segment may be considered susceptible to near neutral SCC failure.

2.2.2.3.3 If "systemic" near neutral pH SCC is determined to be the cause an in-service release, then the assessment segment may be considered susceptible to near neutral pH SCC failure.

2.2.2.3.4 The existence of "isolated" near neutral pH SCC within an assessment segment will require a review of the conditions of the SCC to determine if the assessment segment may be considered susceptible to near neutral SCC failure. The data to be considered in the review may include but is not limited to any inspections, examinations, and evaluations performed in response to the "isolated" near neutral pH SCC occurrence.

2.2.3 The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to metal loss

2.2.3.1 All assessment segments with carbon steel line pipe will be assessed for metal loss. The assessment will be performed in accordance with 195.452(c)(1)(i) for Baseline Assessments and 195.452(j)(5) for Re-Assessments.

2.2.3.2 Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may be considered.

2.2.4 The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to deformation.

2.2.4.1 All assessment segments will be assessed for deformation. The assessment will be performed in accordance with 195.452(c)(1)(i) for Baseline Assessments and 195.452(j)(5) for Re-Assessments.

2.2.4.2 Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may be considered.

2.3 ASSESMENT METHOD SELECTION

2.3.1 The assessment method(s) selected for the assessment segment shall comply with 49 CFR 195.452(c)(1)(i) for Baseline Assessments and 195.452(j)(5) for Re-Assessments.

2.3.2 The Pipeline Integrity Engineer and the Project Manager shall identify and select an appropriate integrity assessment method or combination of methods to assess for metal loss and deformation. The Pipeline Integrity Engineer and the Project Manager shall also identify and select an appropriate integrity assessment method or combination of methods to assess the longitudinal seam or to assess for SCC where it is determined in section 2.2 that the assessment segment is susceptible to Longitudinal Seam Failure or SCC Failure respectively. The assessment method selection process may consider:

2.3.2.1 The data collected in section 2.1 of this procedure

2.3.2.2 The susceptibility to the threats identified in section 2.2 of this procedure.

2.3.2.3 Effectiveness of the assessment method(s)

2.3.2.4 Availability of internal inspection tool or tools capable of detecting the threats of metal loss and deformation

2.3.2.5 Piggability of the line

2.3.2.5.1 Bend radius

2.3.2.5.2 Assessment segment length

2.3.2.5.3 Trap configuration

2.3.2.5.4 Product (type, flow rates)

2.3.2.6 Cost effectiveness of the assessment method

2.3.2.7 Schedule for completion of the integrity assessment

2.3.2.8 Need for ID/OD discriminator

2.3.2.9 Re-inspection recommendations as documented in the results and recommendations from the most recent Information Analysis for the assessment segment.

2.3.3 The following methods are acceptable to assess for the threat of metal loss.

2.3.3.1 Hydrotest

2.3.3.2 Magnetic Flux Leakage ILI Tools

2.3.3.3 Circumferential Magnetic Flux Leakage ILI Tools

2.3.3.4 Ultrasonic Wall Thickness Measurement ILI Tools

2.3.4 The following methods are acceptable to assess for the threat of Deformation.

2.3.4.1 Hydrotest

2.3.4.2 Geometry ILI Tools

2.3.4.3 Magnetic Flux Leakage ILI Tools with all deformations indications investigated

2.3.5 The following methods are acceptable to assess for longitudinal seam threat.

2.3.5.1 Hydrotest

2.3.5.2 Circumferential Magnetic Flux Leakage ILI Tools

2.3.5.3 Ultrasonic crack detection ILI Tools (shear wave)

2.3.6 The following methods are acceptable to assess for the threat of Stress Corrosion Cracking.

2.3.6.1 Hydrotest

2.3.6.2 Ultrasonic crack detection ILI Tools (shear wave)

3.0 DOCUMENTATION

3.1 The integrity assessment method(s) selected shall be documented on the Baseline Assessment Plan and/or on the Assessment Schedule.

3.2 The current integrity assessment method determination documentation including all data gathered and the assessment method selected shall be kept on file until it is replaced by the next integrity assessment method determination.

4.0 REFERENCES

4.1 49 CFR Part 195

4.2 ASME B31.8S – Managing System Integrity of Gas Pipelines

4.3 “Dealing With Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe With Respect To HCA-Related Integrity Assessment”, paper No. ETCE2002/PIPE-29029

4.4 ASME publication, “The History of Line Pipe Manufacturing in North America”

4.5 “Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation”, TTO Number 5 Integrity Management Program Delivery Order DTRS56-02-D-70036

➤➤➤End of Procedure⮜⮜⮜

Change Log

Date	Rev. #	Change Location	Brief Description of Change
8/22/05	1	Title Block	Replaced Paul Klein with Joe Cheek as owner.
8/22/05	1	Title Block	Added "EPOLP Pipeline Integrity Management Program".
8/22/05	1	2.3.2	Modifications to PI position titles performed to reflect recent changes in PI Group position titles.
7/25/07	2	Title Block	Removed the reference to EPOLP, removed the Enterprise logo, and changed the owner to H. Buford Barr.
7/25/07	2	2.2.2, 2.2.3, 2.3.2	Removed "Corrosion Prevention Supervisor".
6/25/09	3	Title Block	Changed owner from Buford Barr to Phu Phan
6/25/09	3	1.0	Inserted "…indentify the applicable integrity threats and". Removed "appropriate"
6/25/09	3	2.1	Changed from "Information considered for the integrity assessment method selection may include the following." to "The Pipeline Integrity Engineer shall ensure the following information is gathered in order to perform the assessment method selection."
6/25/09	3	2.1.1	"Line ID(s) with beginning and ending station if available" is moved to Section 2.1.1.2. Added "The assessment segments in the Baseline Assessment Plan."
6/25/09	3	2.1.1.1	Added "Assessment ID"
6/25/09	3	2.1.1.2	Moved from Section 2.1.1. Changed Line ID(s) with beginning and ending station if available" to "Line ID"
6/25/09	3	2.1.1.3	Added "Segment Description"
6/25/09	3	2.1.2	Moved "Coating type of the segment." to Section 2.1.2.4. Added "The line pipe characteristics listed in PODS, alignment sheets, original construction records or prior assessment method selection documentation."
6/25/09	3	2.1.2.1	Added "Identify if any line pipe material other than carbon steel is present in the assessment segment."
6/25/09	3	2.1.2.2	Moved "diameter" from Section 2.1.7. Changed "diameter" to "Identify all the line pipe diameter(s) present in the assessment segment."
6/25/09	3	2.1.2.3	Moved "seam type" from Section 2.1.7. Changed "seam type" to "Identify if any Low Frequency ERW or Lap welded pipe is present in the assessment segment."
6/25/09	3	2.1.2.3.1	Added "If longitudinal seam type is unknown refer to ASME publication, "The History of Line Pipe Manufacturing in North America", the manufacturer and date of manufacturing of the line pipe to determine if is not Low Frequency ERW or Lap welded pipe."
6/25/09	3	2.1.2.3.2	Added "If no conclusion can be derived from the method above, assume that the unknown pipe constructed prior to 1970 is pre-1970 Low Frequency ERW or Lap welded

Date	Rev. #	Change Location	Brief Description of Change
			pipe.”
6/25/09	3	2.1.2.4	Moved from Section 2.1.2. Changed “Coating type of the segment.” to “Identify if any coating type other than Fusion Bonded Epoxy is present on the pipe body within the assessment segment.”
6/25/09	3	2.1.3	Removed “Coating Condition for the segment. Use the following descriptions for coating condition:” Added “The operating conditions of the assessment segment as obtained from PODS, Pipeline Control or Operations.”
6/25/09	3	2.1.3.1	Removed “Uncoated – Bare pipe with no protective coating.” Added “MOP for the assessment segment.”
6/25/09	3	2.1.3.2	Removed “Poor – Partial or full disbondment with or without coating holidays/anomalies”. Added “Determine the highest MOP% SMYS for the assessment segment.”
6/25/09	3	2.1.3.3	Removed “Good – Fully bonded coating system with no or few holidays/anomalies.”. Added “Identify if the normal operating temperature exceeds 100F as obtained from Pipeline Control or Operations.” - moved from Section 2.1.6
6/25/09	3	2.1.4	Removed “Quality of cathodic protection (CP) for each segment: Use the following descriptions for (CP) quality” Added “If a pressure cycle analysis has been performed on the assessment segment, identify the results of the most recent pressure cycle analysis.”
6/25/09	3	2.1.4.1	Removed “Adequate – This section of line currently meets the minimum requirements set forth by the National Association of Corrosion Engineers Recommended Practice RP-0169 and adopted by reference in DOT 49 CFR, Part 195.571”.
6/25/09	3	2.1.4.2	Removed “Inadequate – The section of line does not currently meet at least one of the minimum requirements set forth by the National Association of Corrosion Engineers Recommended Practice RP-0169 and adopted by reference in DOT 49 CFR, Part 195.571.”
6/25/09	3	2.1.5	Removed “Year of original construction”. Added “The line pipe failure and hydrostatic testing failure history for the assessment segment as obtained from PODS or the most recent hydrostatic test documentation.”
6/25/09	3	2.1.5.1	Added “Identify the number of in-service or hydrostatic testing failures and its cause of failure present in this assessment segment.”
6/25/09	3	2.1.5.2	Added “Identify if a hydrotest was performed to a maximum hydrotest pressure greater than 1.5 times the MOP.”
6/25/09	3	2.1.6	Moved “Does the normal operating temperature of the segment exceed 100F” to Section 2.1.3.3. Added “Obtain the results and recommendations from the most recent Information Analysis for the assessment segment.”
6/25/09	3	2.1.6.1	Added “Identify if the Information Analysis determined the condition of SCC to exist on the assessment segment.”

Date	Rev. #	Change Location	Brief Description of Change
6/25/09	3	2.1.6.2	Added "Identify any threat assessment recommendations from section 2.3 of the previous Information Analysis."
6/25/09	3	2.1.7	Moved "diameter" to Section 2.1.2.2. Moved "seam type" to Section 2.1.2.3. Removed "yield strength" and "wall thickness". Added "Determine if any crack indications (SCC or longitudinal seam cracks) have been found on this assessment segment. Data sources for this determination include but are not limited to in-service failure history hydrostatic testing failure history, and applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may also be considered." from Section 2.1.9.
6/25/09	3	2.1.8	Removed "The number of known in-service seam ruptures and hydrostatic test related seam ruptures."
6/25/09	3	2.1.9	Removed "Has this segment been tested for cracks? If yes, have crack indications been found on this line segment?"
6/25/09	3	2.1.10	Removed "The year and pressure of most recent hydrostatic test for the line segment, if applicable."
6/25/09	3	2.2.1	Changed "The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to Longitudinal Seam Failure" to "The Pipeline Integrity Engineer shall evaluate the assessment segment to identify its susceptibility to Longitudinal Seam Failure"
6/25/09	3	2.2.1.1	Moved to Section 2.2.1.2. Added "The method used to determine each assessment segment's susceptibility to Seam failure is described in the report TTO Number 5 Integrity Management Program Delivery Order DTRS56-02-D-70036 "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation" made available by Department of Transportation Research and Special Programs Administration Office of Pipeline Safety."
6/25/09	3	2.2.1.2	Moved to Section 2.2.1.3. Added " Information available in the paper by John F. Kiefner titled "Dealing With Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe With Respect to HCA-Related Integrity Assessment", paper No. ETCE2002/PIPE-29029 may also be considered." from Section 2.2.1.1.
6/25/09	3	2.2.1.3	Moved to Section 2.2.1.5. Added "Data from ASME publication, "The History of Line Pipe Manufacturing in North America" may be used to determine if ERW line pipe was manufactured with a high frequency mill process." from Section 2.2.1.2
6/25/09	3	2.2.1.4	Added "Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment."
6/25/09	3	2.2.1.5	Added "Failures of longitudinal seam welds during the original construction hydrostatic test are classified as manufacturing related defects and are not fatigue related

Date	Rev. #	Change Location	Brief Description of Change
			failures." from Section 2.2.1.3.
6/25/09	3	2.2.2	Changed "The Pipeline Integrity Engineer shall evaluate the segment to identify its susceptibility to cracking mechanisms such as Stress Corrosion Cracking (SCC)." to "The Pipeline Integrity Engineer shall evaluate the assessment segment to identify its susceptibility to Stress Corrosion Cracking (SCC) failure."
6/25/09	3	2.2.2.1	Changed "The method used to determine each line's susceptibility to high pH SCC is described in ASME B31.8S Appendix A3." to "The method used to determine each assessment segment's susceptibility to high pH SCC failure is described in ASME B31.8S Appendix A3."
6/25/09	3	2.2.2.2	Moved to Section 2.2.2.3. Added "For line pipe that has any coating type other than Fusion Bonded Epoxy that operate at temperatures greater than 100F and with MOP greater than 60% SMYS, additional data shall be gathered as specified in ASME B31.8S Appendix A3."
6/25/09	3	2.2.2.2.1	Removed "Known history of SCC". Added "The additional data to be gathered include age of pipe and distance from a pump station. Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may also be considered."
6/25/09	3	2.2.2.2.2	Removed "Normal operating stress greater than 60% SMYS"
6/25/09	3	2.2.2.2.3	Removed "Coating system classification of "Poor" per 2.1.3 of this document and shields cathodic protection"
6/25/09	3	2.2.2.3	Changed "Near neutral pH SCC susceptibility evaluation of line segments may consider the following:" from Section 2.2.2.2 to "The following information may be considered to determine each assessment segment's susceptibility to near neutral pH SCC failure."
6/25/09	3	2.2.2.3.1	Added "Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment."
6/25/09	3	2.2.2.3.2	Added "If "systemic" near neutral pH SCC is found during in-ditch examinations, then the assessment segment may be considered susceptible to near neutral pH SCC failure."
6/25/09	3	2.2.2.3.3	Added "If "systemic" near neutral pH SCC is determined to be the cause an in-service release, then the assessment segment may be considered susceptible to near neutral SCC failure."
6/25/09	3	2.2.2.3.4	Added "The existence of "isolated" near neutral pH SCC within an assessment segment will require a review of the conditions of the SCC to determine if the assessment segment may be considered susceptible to near neutral SCC failure. The data to be considered in the review may include but is not limited to any inspections, examinations, and evaluations performed in response to the "isolated"

Date	Rev. #	Change Location	Brief Description of Change
			near neutral pH SCC occurrence."
6/25/09	3	2.2.3	Changed "corrosion" to "metal loss"
6/25/09	3	2.2.3.1	Added "All assessment segments with carbon steel line pipe will be assessed for metal loss. The assessment will be preformed in accordance with 195.452 (c)(1)(i) for Baseline Assessments and 195.452(i) 95) for Re-Assessments."
6/25/09	3	2.2.3.2	Added "Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may be considered."
6/25/09	3	2.2.4	Changed "Third Party Damage" to "deformation"
6/25/09	3	2.2.4.1	Added "All assessment segments will be assessed for deformation. The assessment will be performed in accordance with 195.452(c)(1)(i) for Baseline Assessments and 195.452(j)(5) for Re-Assessments."
6/25/09	3	2.2.4.2	Added "Applicable results and recommendations from section 2.2 and 2.3 of the most recent Information Analysis for the assessment segment may be considered."
6/25/09	3	2.3.1	Changed "The Baseline Assessment Plan tool selection shall comply with 49CFR195.452 (c)." to "The assessment method(s) selected for the assessment segment shall comply with 49 CFR 195.452(c)(1)(i) for Baseline Assessments and 195.452(i)(5) for Re-Assessments."
6/25/09	3	2.3.2	Changed "The Pipeline Integrity Engineer and the Project Manager shall identify and select appropriated integrity assessment method or combination of methods to address the threats identified for the pipeline segment. The assessment method(s) selection may consider:" to "The Pipeline Integrity Engineer and the Project Manager shall identify and select appropriated integrity assessment method or combination of methods to assess for metal loss and deformation. The Pipeline Integrity Engineer and the Project Manager shall also identify and select an appropriate integrity assessment method or combination of methods to assess the longitudinal seam or to assess for SCC where it is determined in section 2.2 that the assessment segment is susceptible to Longitudinal Seam Failure or SCC Failure respectively. The assessment method selection process may consider:"
6/25/09	3	2.3.2.4	Changed "Availability of the internal tools or other tools capable of detecting metal loss and deformation anomalies." to "Availability of internal inspection tool or tools capable of detecting the threats of metal loss and deformation."
6/25/09	3	2.3.2.5.4	Added "(type, flow rates)"
6/25/09	3	2.3.2.9	Added "as documented in the results and recommendations from the most recent Information Analysis for the assessment segment."

Date	Rev. #	Change Location	Brief Description of Change
6/25/09	3	2.3.2.10	Removed "The MOP of the segment, as required."
6/25/09	3	2.3.3	Added a subsection to identify methods acceptable for assessing for the threat of metal loss.
6/25/09	3	2.3.4	Added a subsection to identify methods acceptable for assessing for the threat of Deformation.
6/25/09	3	2.3.5	Added a subsection to identify methods acceptable for assessing for longitudinal seam threat.
6/25/09	3	2.3.6	Added a subsection to identify methods acceptable for assessing for the threat of Stress Corrosion Cracking.
6/25/09	3	3.1	Changed "The integrity assessment method(s) selected for the baseline assessment shall be documented on the Baseline Assessment Plan." to "The integrity assessment method(s) selected shall be documented on the Baseline Assessment Plan and/or on the Assessment Schedule."
6/25/09	3	3.2	Added "including all data gathered and the assessment method selected shall"
6/25/09	3	4.2	Added "-Managing System Integrity of Gas Pipelines"
6/25/09	3	4.5	Added ""Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation", TTO Number 5 Integrity Management Program Delivery Order DTRS56-02-D-70036."

1.0 PURPOSE:

1.1 The purpose of this procedure is to establish a standardized method for measuring the effectiveness of the Integrity Management Program (IMP) for liquids in assessing and evaluating integrity and in protecting the high consequence areas.

2.0 PROCEDURE:

At least once each calendar year the following shall be performed for the previous calendar year ("subject year").

2.1 Performance Measures

2.1.1 Selected Activity Measures

Collect the following measures that monitor the surveillance and preventive activities that have been implemented.

- Number of hazardous liquids pipeline miles operated at year end of the subject year.
- Number of hazardous liquids pipeline miles in the IMP at year end of the subject year.
- Number of hazardous liquids pipeline HCA miles in the IMP at year end of the subject year.
- Number of HCA pipeline miles scheduled to be integrity assessed as identified in the BAP at year end of the subject year.
- Number of HCA pipeline miles integrity assessed at year end of the subject year.
- Number of new cathodic protection systems installed during the subject year.
- Number of new cathodic protection test points installed during the subject year.
- Total length of pipe recoated as a result of pipeline recoating projects during the subject year.
- Miles of close interval cathodic protection survey conducted during the subject year.
- Miles of IR free cathodic protection survey conducted during the subject year.

- Number of new internal corrosion monitoring sites installed during the subject year.
- Number of new internal corrosion chemical injection sites installed during the subject year.

2.1.2 Deterioration Measures

Collect the following operation and maintenance information to evaluate Deterioration Measures.

- Number of ILI tool metal loss digs in an HCA during the subject year.
- Number of ILI tool metal loss digs in a non-HCA during the subject year.
- Number of ILI tool deformation digs in an HCA during the subject year.
- Number of ILI tool deformation digs in a non-HCA during the subject year.
- Number of ILI tool crack-like digs in an HCA during the subject year.
- Number of ILI tool crack-like digs in a non-HCA during the subject year.
- Number of ILI tool Immediate Criteria digs in an HCA during the subject year.
- Number of ILI tool 60-day Criteria digs in an HCA during the subject year.
- Number of ILI tool 180-day Criteria digs in an HCA during the subject year.
- Number hydrotest ruptures addressed in an HCA during the subject year.
- Number hydrotest ruptures addressed in a non-HCA during the subject year.
- Number hydrotest leaks addressed in an HCA during the subject year.
- Number hydrotest leaks addressed in a non-HCA during the subject year.

2.1.3 Failure Measures

Collect the following leak history, incident response, and product lost measures.

2.1.3.1 Line Pipe

- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases in an HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases in a non-HCA during the subject year.

- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by product type in an HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by product type in a non-HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by cause in an HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by cause in a non-HCA during the subject year.

2.1.3.2 Facilities

- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases in an HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases in a non-HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by product type in an HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by product type in a non-HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by cause in an HCA during the subject year.
- Number, w/quantity released and recovered, of non-maintenance DOT reportable releases by cause in a non-HCA during the subject year.

2.2 Effectiveness Review

The Pipeline Integrity Manager, Pipeline Integrity Engineering Supervisor and Asset Integrity Director shall perform the following from the data gathered in Section 2.1 and as specified.

2.2.1 Compare the HCA pipeline miles scheduled to be integrity assessed against the HCA pipeline miles that have been integrity assessed for the subject year. If the miles scheduled is greater than the miles completed, indicate the probable reason(s) why.

2.2.2 Compare the subject year's number of ILI tool metal loss digs in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.3 Compare the subject year's number of ILI tool deformation digs in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.4 Compare the subject year's number of ILI tool crack like digs in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.5 Compare the subject year's number of ILI tool Immediate Criteria digs in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.6 Compare the subject year's number of ILI tool 60-day Criteria digs in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.7 Compare the subject year's number of ILI tool 180-day Criteria digs in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.8 Compare the subject year's number of hydrotest ruptures addressed in an HCA to the previous year's. If the subject year's number is not less, indicate the probable reason(s) why.

2.2.9 Compare the subject year's total volume of non-maintenance DOT reportable releases to the previous year's. If the subject year's total is not less, indicate the probable reason(s) why.

2.2.10 Compare the subject year's total number of non-maintenance DOT reportable releases to the previous year's. If the subject year's total is not less, indicate the probable reason(s) why.

2.2.11 Calculate the percent of the subject year's number of releases by cause and compare to the industry's percent of releases by cause as published by the OPS. If the subject year's percent of releases by cause is greater than that published by OPS, indicate the probable reason(s) why.

2.2.12 Evaluate and analyze the performance measures of the IM Program and develop findings and conclusions about the effectiveness of the IM Program in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. The evaluation may consider, but is not limited to, the following:

2.2.12.1 Program goals in identifying and protecting High Consequence Areas

2.2.12.2 Evaluation of the effectiveness of the Preventative & Mitigative Measures (P&MMs), which may include a review of past P&MM recommendations and their results.

2.2.12.3 Evaluation of the effectiveness of the Integrity Assessment and

Integrity Assessment Results Analysis, which may include a review of current year results against results available from years since the implementation of the IMP.

2.2.12.4 Trending of number of non-maintenance DOT reportable releases

2.3 Documentation & Communication

2.3.1 The Pipeline Integrity Manager shall create a report that identifies the collected data from Section 2.1 and findings and conclusions about the effectiveness of the program from Section 2.2. This report shall be distributed to the Executive Management of Engineering, Operations, Asset Integrity, and all affected Operations' Supervisors and Managers.

2.3.2 The report will be kept on file for the life of the pipeline.

3.0 REFERENCES:

3.1 Regulatory

49 CFR 195.452

16 TAC 8.101

3.2 **Related Policies/Procedures** -

3.2.1 IMP Program Evaluation process (Section 8)

3.2.2 Forms and Attachments - N/A

4.0 DEFINITIONS:

➤➤➤End of Procedure⮘⮘⮘

Change Log

Date	Rev. #	Change Location	Brief Description of Change
8/22/05	1	3.2.1	Removed "/chapter".
8/22/05	1	Title Block	Added "EPLOP Pipeline Integrity Management Program".
8/22/05	1	2.0	Modifications to PI position titles performed to reflect recent changes in PI Group position titles.
8/22/05	1	1.0	Added "for liquids".
1/03/07	2	Title Block	Changed owner from Joe Cheek to F. Henry Martinez
1/03/07	2	Section 2.1	Added Section 2.1.1 – "Selected Activity Measures", Section 2.1.2 – "Deterioration Measures", and Section 2.1.3 – "Failure Measures". Previous reference to Attachment A removed.
1/03/07	2	Section 2.2	Added Section 2.2 - "Effectiveness Review". Previous guidance for review of data removed.
1/03/07	2	Section 2.3	Relocated the documentation and communication information to this section. Expanded the documentation distribution.
1/03/07	2	Section 3.2	Removed "Attachment A-IMP Effectiveness Performance Indicators" from list.
7/18/07	3	Title Block	Removed the reference to EPOLP and removed the Enterprise logo.
11/27/07	4	2.1.1	Removed "Total number of cathodic protection test points at year end of the subject year."
11/27/07	4	2.1.1	Added "Number of new cathodic protection test points installed during the subject year."
11/27/07	4	2.1.1	Removed "Total number of internal corrosion monitoring sites at year end of the subject year."
11/27/07	4	2.1.1	Removed "Total number of internal corrosion chemical injection sites at year end of the subject year."
9/9/08	5	2.2.12	Removed section, OPS no longer publishes this information
9/9/08	5	2.2.13	Removed section, OPS no longer publishes this information
9/9/08	5	2.2.14	Removed section, OPS no longer publishes this information
6/26/09	6	Owner	Changed owner from Henry Martinez to Phu Phan
6/26/09	6	2.1.1	Removed "These measures may provide insight into how the various elements of the IMP are being implemented."
6/26/09	6	2.1.2	Changed "which may indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities." to "to evaluate Deterioration Measures."

6/26/09	6	2.1.3	Removed "These measures may indicate progress towards fewer spills and less damage."
6/26/09	6	2.2	Added "Pipeline Integrity Engineering Supervisor and Asset Integrity Director"
6/26/09	6	2.2.12	Added a subsection to "Evaluate and analyze the performance measures of the IM Program and develop findings and conclusions about the effectiveness of the IM Program in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas……"
6/26/09	6	2.3.1	Inserted "…and conclusions about the effectiveness of the program" and "…Asset"