U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

233 Peachtree Street Ste. 600
Atlanta, GA 30303

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 18, 2010

Jeryl Mohn
Sr. Vice President, Operations & Engineering
Panhandle Energy
5444 Westheimer Road
Houston, Texas 77056-5306

CPF 2-2010-1009M

Dear Mr. Mohn:

On April 12-16 and April 26-30, 2010, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) inspected Panhandle Energy's Gas Integrity Management Program (IMP) procedures in Houston, Texas, pursuant to Chapter 601 of 49 United States Code.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within Panhandle Energy's plans or procedures, as described below:

1. **§192.911 What are the elements of an integrity management program?**
   (a) An identification of all high consequence areas, in accordance with §192.905.

   §192.905 How does an operator identify a high consequence area?
   (c) Newly identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

   Panhandle Energy's Standard Operating Procedure (SOP) J.01 was inadequate because it did not define or include timeframes necessary for completing all the processes involved in identifying new high consequence areas (HCA). HCA identification processes include, but are not necessarily limited to, the methods an operator uses to obtain information about the area around a pipeline segment, the evaluation method(s) an operator chooses to establish an HCA, and the process an operator uses to incorporate the new identified HCA into its baseline assessment plan.

2. **§192.911 What are the elements of an integrity management program?**
(b) A baseline assessment plan meeting the requirements of § 192.919 and §192.921.

§192.919 What must be in the baseline assessment plan?
An operator must include each of the following elements in its written baseline assessment plan:
(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

- **Item 2A: §192.919(e)**

Panhandle Energy's IMP procedures were inadequate because Panhandle Energy had not incorporated the requirements to minimize the environmental and safety risks associated with dewatering pipeline segments after hydro-testing into its hydrostatic pressure testing procedures.

§192.921 How is the baseline assessment to be conducted?
(a) Assessment methods. An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 192.917).
(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see § 192.7), Section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

- **Item 2B: §192.921(a)(1)**

Panhandle Energy's IMP assessment method selection procedures were inadequate in that the procedures did not require the consideration of internal in-line inspection (ILI) tool tolerances to effectively address pipeline threats. Additionally, Panhandle Energy's IMP procedures were inadequate because the procedures lacked specific requirements for comparing recent ILI runs to previous ILI runs for monitoring anomalies.

3. **§192.911 What are the elements of an integrity management program?**
(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
(a)Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2, which are grouped under the following four categories: (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; (2) Static or resident threats, such as fabrication or construction defects; (3) Time independent threats such as third party damage and outside force damage; and (4) Human error.

Panhandle Energy's Standard Operating Procedure (SOP) J.09 was inadequate because the procedure did not completely address or identify potential interactive threats to pipeline integrity. Potential threats to pipeline integrity include those threats identified using the four threat categories listed above either as a stand-alone threats or as threats interacting with each other.

4. **§192.911 What are the elements of an integrity management program?**
(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.

§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?
(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).
(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 3, the plan's procedures for preassessment must include- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and (ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502-2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) Indirect examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include-

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) ******

(4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include-

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE RP0502-2002.)

- **Item 4A: §192.925(b)(1)**

  Panhandle Energy's SOP J.10 was inadequate because the procedure did not provide process details on the specific criteria and data that the Subject Matter Expert (SME) uses to identify ECDA regions. Also, SOP J.10 did not provide adequate ECDA Region determination details. Additionally, Panhandle Energy's procedure did not adequately document the use of more restrictive criteria when conducting ECDA pre-assessment for the first time on a covered segment.

- **Item 4B: §192.925(b)(2)**

  Panhandle Energy's ECDA procedures did not adequately specify physical spacing for the measurement of soil resistivity when used as an indirect inspection tool. Also, Panhandle Energy's procedures for taking soil resistivity readings at excavation locations did not meet the intent of applying more restrictive criteria for indirect inspection.

- **Item 4C: §192.925(b)(4)**

  Panhandle Energy's IMP ECDA post assessment procedures did not adequately establish criteria to evaluate long term ECDA program effectiveness as required by NACE RPO502-2002, Section 6.4.3, which PHMSA has incorporated by reference.

5. **§192.911 What are the elements of an integrity management program?**
(e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.

§192.933 What actions must be taken to address integrity issues?
(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.
(d) Special requirements for scheduling remediation.-
(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:
(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.
(ii) A dent that has any indication of metal loss, cracking or a stress riser.
(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

Panhandle Energy's procedure SOP J.14 entitled "*In-Line Inspection: Data Integration, Analysis, and Response*" is inadequate because it did not address anomalies exceeding 80% wall loss as an immediate repair condition.

6. **§192.911 What are the elements of an integrity management program?**
(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

Panhandle Energy's Management of Change (MOC) procedures were inadequate because the procedures did not require the review and analysis of the implications of pipeline or system changes to the IMP prior to implementing the changes. MOC procedures must identify and consider the impact of changes to pipeline systems and their integrity.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 60 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 2-2010-1009M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Wayne T. Lemoi
Director, Office of Pipeline Safety
PHMSA Southern Region

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*