U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 15, 2007

Mr. Ron McClain
Vice President of Operations & Engineering
Kinder Morgan Energy Partners, L.P.
500 Dallas Street, Suite 1000
Houston, TX 77002

CPF 4-2007-5004M

Dear Mr. McClain:

On September 25-29; October 10-13; and October 30-November 3, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Arizona Corporation Commission, and the California State Fire Marshall pursuant to Chapter 601 of 49 United States Code inspected your procedures for your Integrity Management Program (IMP) in Houston, TX, Alpharetta, GA, and Orange, CA, respectively.

On the basis of the inspection, PHMSA has identified the apparent inadequacy found within Kinder Morgan's plan or procedure and are described below:

1. **§195.452 Pipeline integrity management in high consequence areas.**

   (f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section)

(h) What actions must an operator take to address integrity issues?

(1) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with §195.422 when making a repair.

(2) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

Appendix H7.1, Section 4.4.2.3 requires that a minimum of one validation dig be conducted for each ILI tool run within 60 days of receiving the final report. A consumption of 60 days for validating the results of the ILI report and conducting validation dig delays declaration of discovery of anomalous conditions and potentially delays the repair of anomalies meeting 60-day criteria beyond the required timeframe. Appendix H7.3 details the process and procedures used during the ILI Metal Loss Tool Grading and Validation. The Inspection Team reviewed proposed changes and detail to the discovery process for specific tools (and threats), and we continue to review how this process for discovery timeframes align with rule requirements and PHMSA expectations. The process to declare discovery within typical ILI tool applications must be sufficiently detailed to ensure consistent application.

2. § 195.452 Pipeline integrity management in high consequence areas.

(f) ***see above***

(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(j) ***What is a continual process of evaluation and assessment to maintain a pipeline's integrity?***

(1) General. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.

(2) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base

the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) Assessment intervals. An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

KMEP must detail the specific process inputs used in the hydrostatic pressure test reassessment interval determination process to ensure the 195.452(j)(3) requirements are met.

3. § 195.452 Pipeline integrity management in high consequence areas.

(f) ***see above***

(2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(c) What must be in the baseline assessment plan?

(1) An operator must include each of the following elements in its written baseline assessment plan:

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(C) External corrosion direct assessment in accordance with §195.588;

§ 195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section for performing external corrosion direct assessment. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) General. You must follow the requirements of NACE Standard RP0502–2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment.

(2) Pre-assessment. In addition to the requirements in Section 3 of NACE Standard RP0502–2002, the ECDA plan procedures for pre-assessment must include—

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

(ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and

(iii) If you utilize an indirect inspection method not described in Appendix A of NACE Standard RP0502–2002, you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502–2002, the 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 pipeline segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:

(A) The known sensitivities of assessment tools;

(B) The procedures for using each tool; and

(C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) For each indication identified during the indirect examination, criteria for—

(A) Defining the urgency of excavation and direct examination of the indication; and

(B) Defining the excavation urgency as immediate, scheduled, or monitored; and

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

(4) Direct examination. In addition to the requirements in Section 5 of NACE Standard RP0502–2002, the procedures for direct examination of indications from the indirect examination must include—

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

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE Standard RP0502–2002 provides guidance for criteria); or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE Standard RP0502–2002 provides guidance for criteria);

(iii) Criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis you will reclassify and re-prioritize any of the provisions specified in Section 5.9 of NACE Standard RP0502–2002.

(5) Post assessment and continuing evaluation. In addition to the requirements in Section 6 of NACE Standard UP 0502–2002, the 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 pipeline 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 pipeline segment at an interval less than that specified in Sections 6.2 and 6.3 of NACE Standard RP0502–2002 (see Appendix D of NACE Standard RP0502–2002).

IMP Appendix H8.2 provides the basis for implementing an ECDA plan, and the procedure must modified to provide the detail necessary to consistently develop a "business unit asset specific" ECDA plan by specifying the requirements of §195.588 and NACE RP 0502 standard, as appropriate.

In regard to Items 1, 2, and 3 listed above, KMEP provided finalized documentation via email to PHMSA on December 1, 2006, of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required in response to this Notice.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

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