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U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W Dakota Ave , Suite 110
Lakewood, CO 80228

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 13, 2008

Mr. Daniel F. Riemer
Manager, Marketing and Transportation
Marathon Oil Company
5555 San Felipe
Houston, TX 77056

CPF 5-2008-0003W

Dear Mr. Riemer:

On August 27-30, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your Integrity Management Program (IMP) in Anchorage, Alaska.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violation(s) are:

1. **§192.905 How does an operator identify a high consequence area?**
   a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system.

An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix E.I. for guidance on identifying high consequence areas.)

1a. Marathon system maps do not provide the level of detail and accuracy to establish the pipeline segment locations that are located in high consequence areas (HCAs).

Evidence: A.01.c- Chugach Power Plant map – file 043035 GPB-photo.pdf.

1b. Marathon's covered segments that impact identified sites do not include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle for those potential impact circles that contain an identified site.

Evidence: A.02.b- Chugach Power Plant map – file 043035 GPB- photo.pdf .

1c. Marathon's definition for identified sites provided in IMP-6-001, section 2.1.2 is not consistent with the Integrity Management Rule. It inappropriately limits identified sites to only those that are identified by public safety officials and Local Emergency Planning Committees.

Evidence: A.03.b- HCA Segment ID, IMP-6-001, section 2.1.2.

1d. Marathon's Integrity Management Plan does not include procedural steps establishing how it is determined that potential impact circles contain identified sites and when a potential impact circle does contain an identified site how are the boundaries of the covered segment established and documented.

Evidence: A.04.c- Marathon Transmission Pipeline Integrity Management Program, section 6-1 – 6.1.2, HCA Segment ID, IMP-6-001.

2. §192.921 How is the baseline assessment to be conducted?

(b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in § 192.917.

The West Side Cook Inlet Gas Gathering System (CIGGS) pipeline has experienced a failure due to SCC; however, an assessment method has not been selected and completed for this segment that will address the potential threat of Stress Corrosion Cracking (SCC).

Evidence: B.04.e- The Baseline Assessment plan only indicates In Line (ILI) as an assessment technique for the West Side CIGGS segment.

3. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

(b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

Marathon has not completed an updated data integration process that includes the results of completed integrity assessments and other pertinent data that has been identified since the integrity assessments have been completed.

Evidence: C.02.b- Kenai-Nikiski Pipe Line (KNPL) system maps do not reflect data learned through completion of baseline assessments which were completed in 2005.

4. **§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?**

(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d) For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

Marathon's Integrity Management Program does not specify a timeframe for the performance of periodic evaluations of pipeline integrity based on data integration and risk assessment as required by §192.937(b).

Evidence: F.01.c- Natural Gas Transmission Pipeline Integrity Management Program, sections 6.4 – 6.4.4.

5. **§192.935 What additional preventive and mitigative measures must an operator take?**

(b) Third party damage and outside force damage—

(1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

Marathon's procedure, IMP-6-007, does not require that all un-monitored excavations be investigated for potential pipe or coating damage.

Evidence: H.02.a- Preventive Measures, IMP-6-007, section 2.2.3.

6. **§192.935 What additional preventive and mitigative measures must an operator take?**

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors--swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

Marathon has not completed an analysis to determine if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas.

Evidence: H.07.a- Marathon's Natural Gas Transmission Pipeline Integrity Management Program, section 6.3.4.5 and Procedure IMP-6-007, section 2.3, – program has not been implemented.

7. **§192.945 What methods must an operator use to measure program effectiveness?**

(a) General. An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four

overall performance measures specified in ASME/ANSI B31.8S (ibr, see §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

Marathon has not measured and documented the threat-specific metrics of ASME B31.8S-2004, Appendix A on a semi-annual basis. The IMP does not include requirements that specify that these measures must be measured.

Evidence: I.01.b- Natural Gas Transmission Pipeline Integrity Management Program, section 7.

8. **§192.909 How can an operator change its integrity management program?**

(a) General. An operator must document any change to its program and the reasons for the change before implementing the change.

Marathon's Management of Change (MOC) form for IMP program changes does not designate review and approval by the Operations Superintendent as required by the process defined in the IMP Program, section 9.

Evidence: K.01.a- Natural Gas Transmission Pipeline Integrity Management Program, section 9.

9. **§192.915 What knowledge and training must personnel have to carry out an integrity management program?**

(c) Persons responsible for preventive and mitigative measures. The integrity management program must provide criteria for the qualification of any person--

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or
(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

Marathon's specific qualifications for key personnel that execute activities within the integrity management program have not been defined by the IMP. The IMP only provides general qualifications.

Evidence: L.02.d- Natural Gas Transmission Pipeline Integrity Management Program, section 5

10. §192.911 What are the elements of an integrity management program?

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by--

(1) OPS; and
(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

Marathon's Integrity Management Program does not include a specific requirement that the operator's risk analysis or integrity management program will be submitted to PHMSA or State or local pipeline safety authorities upon their request.

Evidence: N.01.a- Natural Gas Transmission Pipeline Integrity Management Program, section 4.0.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item(s) identified in this letter. Failure to do so will result in Marathon Oil Company being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2008-0003W.** 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).

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 Jon Strawn (#119465)