U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

**NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER**

**CERTIFIED MAIL - RETURN RECEIPT REQUESTED**

November 7, 2011

Geoffrey Craft
Vice President Operations
ExxonMobil Pipeline Company
800 Bell Street, Room 3180 H
Houston, TX 77002

**CPF 4-2011-5016**

Dear Mr. Craft:

On March 31 and April 1, 2011, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected issues related to previously filed Safety Related Condition Reports and portions of your integrity management program in Houston, Texas.

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. §195.302 General requirements.**

**(a) Except as otherwise provided in this section and in §195.305(b), no operator may operate a pipeline unless it has been pressure tested under this subpart without leakage. In addition, no operator may return to service a segment of pipeline that has been replaced, relocated, or otherwise changed until it has been pressure tested under this subpart without leakage.**

**(c) Except for pipelines that transport HVL onshore, low-stress pipelines, and pipelines covered under §195.303, the following compliance deadlines apply to pipelines under**

**paragraphs (b)(1) and (b)(2)(i) of this section that have not been pressure tested under this subpart:**

**(1) Before December 7, 1998, for each pipeline each operator shall–**

**(i) Plan and schedule testing according to this paragraph; or**

**(ii) Establish the pipelines maximum operating pressure under §195.406(a)(5).**

**(2) For pipelines scheduled for testing, each operator shall–**

**(i) Before December 7, 2000, pressure test–**

**(A) Each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and**

**(B) At least 50 percent of the mileage (length) of all other pipelines; and**

**(ii) Before December 7, 2003, pressure tests the remainder of the pipeline mileage (length).**

ExxonMobil (operator) operated pipelines that have not been pressure tested. The operator did not establish a plan nor pressure test its South Bend to New Iberia 12-inch Crude pipeline by the deadline as required. The operator provided internal documentation assessing the South Bend to New Iberia 12 Inch Crude pipeline where the records indicate the operator had never hydrostatically tested the pipeline. One operator report titled "Long Seam Susceptibility Criteria for Baseline Assessment" dated 3/24/03 indicates that there was a known seam threat on this pipeline. A subsequent email from Erik M. Wimberly to Rikky D. Miller dated 3/31/04, further references the Baseline Assessment and the fact that "without a documented hydrostatic test record for the 1952 LW and ERW pipe, our process stipulates that a baseline seam integrity assessment is needed." This indicates that as of 3/31/04, the operator had not hydrostatically tested the pipe according to the requirements of the regulations. At the time of the inspection, no hydrostatic test had been conducted.

The operator did not pressure test numerous other pipelines in the Southwest Region by the deadline as required by the regulation. In the course of the inspection, the operator was asked if there were other systems which did not have appropriate test records. The operator provided the inspection team with a document titled, "Systems Lacking DOT Hydrotest Documentation Test Plans and Deadlines" dated 3/28/11 with an attached spreadsheet listing the subject systems. The spreadsheet lists a total of 27 systems which do not have pressure tests. All exceeded the operator's stated deadline of December 7, 2002. A total of 615.7 miles of the operator's system does not have pressure tests.

In the alternative the operator was unable to provide the hydrostatic test records required by §195.310 Records, which requires that a record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.

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

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

**(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.**

The operator inappropriately extended discovery dates on at least two occasions. The operator's procedure titled "Integrity Management Program in High Consequence Areas" Section 4. Repair Criteria, dated 9/30/10, contains the same language as the regulations related to the definition of "Discovery" but gives no direction in this procedures as to exactly what constitutes "impracticable" and the rationales used by the operator in order to establish that the subject events were "impracticable" are not acceptable.

The first instance involves the LA-16A & 16B: 20"/22" Melville to Boyce Crude pipelines. The operator established criteria for evaluating tool runs and determined that it had a successful tool run on 10/25/2007 but it inappropriately extended the discovery date from the latest allowable date of 4/22/2008 to 9/30/2008. The operator's document titled "Form 1.2: Integrity Management Program Manual Exception Request" Exception Request 2008-02: Extend the Discovery Period for 20"/22" allowed for an extension up to 6/21/2008. A second document titled "LA-16A & 16B: 20"/22" Melville to Boyce Crude" Revision 1: 9/30/2008 shows an additional request for extension on 6/12/08 with a final Discovery Date of 9/30/08.

With regard to the first document mentioned above, the operator indicates the need for the extension as:

> "The tool vendor PII took 159 days of the 180 day Discovery period to provide the preliminary report for the October 24, 2007 TFI tool run… PII expects to deliver the final report on or around 4/15/2008. Therefore, an exception is being requested to extend the period of Discovery an additional 60 days until 6/21/2008 in order to provide time for receipt of the final report from the vendor, analysis of results, completing the Data Integration, and risk and threat analysis needed to develop the repair plan and meet Discovery for the line."

A Second Extension was implemented by the operator and is provided as "Exception 2008-02A" dated 6/12/08, where it indicates the second extension was approved with a Discovery Date of September 30, 2008.

PHMSA's FAQ 4.13, which addresses evaluation and problems with ILI runs says, " …, in the event a series of ILI tool runs is used to complete an assessment, the 180 day discovery period for each individual tool run begins when that specific tool reaches the receiver if the tool provides sufficient information to determine if a particular repair criteria condition exists. These activities are considered to occur after the completion of the "assessment". In those rare instances in which only a partial assessment is performed operators will be expected to evaluate the results that were obtained within 180 days of the early termination, in accordance with 195.452(h)(2). If however, the quality of the partial data is suspect and an entire rerun is to be performed, then the evaluation will be expected within 180 days after the successful rerun."

The fact that the vendor took 159 of the 180 is not sufficient to extend the deadline of discovery. The operator did not establish legitimately "impracticable" reasons why the 180-day discovery date needed to be extended.

The second instance involves the West Delta 73 to Grand Isle Station. The operator first ran a Rosen ILI tool on 2/2/10 and received a preliminary report on 3/12/10. A subsequent GE ILI tool was run on 5/31/10 and the operator received a preliminary report on 6/21/10. Based off of the first ILI run and the fact that the preliminary report was received on 3/12/2010, discovery should have been made no later than 3/12/2010. The operator claimed discovery based on the successful tool run of 5/30/10 with a final Discovery date of 11/26/10.

The operator utilized a statistical approach to invalidate the original tool run using data from a machined block of anomalies in the pipeline, specifically designed for calibration purposes. The operator claimed the machined block caused distorted signals on the ILI tool due to the machining of the block. The operator provided Unity Charts for both the Rosen and GE runs where the operator claimed the Unity Charts demonstrated the problems with the Rosen tool. In fact, the Unity Charts demonstrate the findings were within acceptable parameters. The operator's own procedures titled, "Integrity Management Program in High Consequence Areas, 4. Repair Procedures, Section 4.3.1.4. Adjusting Repair Plans with Actual Data" dated 9/30/2010, page 109 – 110, describes the use of Unity Charts. The procedure states, "With a highly accurate tool, most of the indications should match up to the field excavations within the "error band" identified by the tool vendor (outlined in red on the unity chart)." The Unity Charts provided by the operator show the majority of indications within this acceptable band.

The operator also provided a spreadsheet with a discreet sampling of 10 data points obtained from the initial ILI run indicates all 10 anomaly conditions range from 70% to 78% wall loss with the whereas the second ILI run indicates all 10 anomaly conditions range from 55% to 70% wall loss. The conditions identified would have been classified 180-day conditions for both ILI runs. The operator sold the system prior to addressing the 180-day conditions and only addressed two (2) conditions identified as immediate conditions.

In this second instance, the operator did not prove the original tool run was defective justifying running the second tool run and delaying the discovery date. The operator was not able to provide concurrence from the tool vendor that the tool was in error for the length of the line.

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

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

**(4) Special requirements for scheduling remediation.**

**(i) Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in Section 451.6.2.2 (b) of ANSI/ASME B31.4 (incorporated by reference, see § 195.3). etc.**

The operator failed to evaluate and repair immediate repair conditions in an acceptable amount of time for at least 3 immediate conditions.

The operator provided a procedural flowchart titled, "Integrity Management Program in High Consequence Areas, Figure 2.5: Discovery and SRC Review/Determination Process" dated 9/30/2010. That flow chart indicates that the operator is supposed to "Confirm Immediate Repairs to be completed in 5 business days."

With regard to (i) Immediate repairs on the West Delta 73 pipeline the operator initially identified 31 immediate conditions, reran the tool and subsequently received a second preliminary report and finally conducted an assessment and repair of only two (2) immediate conditions, but did so over eight (8) months after the first preliminary report and over four (4) months after the second preliminary report was received. The operator only made two (2) immediate condition repairs, one on 11/2/2010 and the second on 11/4/2010, prior to the pipeline being sold.

With regard to (i) Immediate repairs on the SMI 69B to South Bend pipeline the operator received the preliminary report back on 12/8/10 and did not make the only immediate repair until 2/17/11.

PHMSA FAQ 7.4 clearly states that "repairs must be made as soon as practicable?" It is not reasonable to allow the operator to extend "what is practicable" beyond the 5 business days stated within the operator's own procedure. This defeats the purpose of addressing "immediate" conditions immediately.

Similarly, the operator failed to reduce pressure on the same two pipelines in a timely manner. The operator's Safety Related Condition Report for the West Delta 73 pipeline states that "Due to low operational risk levels EMPCo does not plan on reducing operating pressure while the repairs are completed." For the SMI 69B to South Bend pipeline the operator indicated "no pressure reduction; operates <40% SMYS."

This practice of the operator is contrary to the regulation and PHMSA's FAQ 7.15 a. clearly states, "the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present. These may be well below the "maximum operating pressure" for the pipe, which was the case in this situation."

## Proposed Civil Penalty

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. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violation(s) and has recommended that you be preliminarily assessed a civil penalty of $151,100 as follows:

| Item number | PENALTY |
|---|---|
| 1. | $109,500 |
| 2. | $20,800 |
| 3. | $20,800 |

## Proposed Compliance Order

With respect to each of the items pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to ExxonMobil Pipeline Company. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

## Response to this Notice

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.

In your correspondence on this matter, please refer to **CPF 4-2011-5016** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

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

Enclosures: *Proposed Compliance Order*
*Response Options for Pipeline Operators in Compliance Proceedings*

## PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to ExxonMobil Pipeline Company a Compliance Order incorporating the following remedial requirements to ensure the compliance of ExxonMobil Pipeline Company with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to a required hydrostatic test, the operator must as soon as possible pressure test the pipelines according to the requirements of 195 Subpart E – Pressure Testing.

2. In regard to Item Number 2 of the Notice pertaining to Discovery, the operator must revise its procedures to provide better guidance on acceptable rationales for extension of dates related to Discovery.

3. In regard to Item Number 3 of the Notice pertaining to immediate repair conditions, the operator must revise its procedures to ensure immediate repairs are implemented within 5 business days.

4. In regard to Item Number 3 of the Notice pertaining to required pressure reductions, the operator must revise its procedures to ensure any and all required pressure reductions occur within 5 business days.

5. The operator must revise its procedures within 30 days after receipt of a Final Order. The operator must complete all hydrostatic tests within 1 year after receipt of a Final Order.

6. It is requested (not mandated) that ExxonMobil Pipeline Company maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to R. M. Seeley, Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration. It is requested that these costs be reported in two categories:
   1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and
   2) total cost associated with replacements, additions and other changes to pipeline infrastructure.