NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

<u>CERTIFIED MAIL - RETURN RECEIPT REQUESTED</u>

November 6, 2013

Mr. Gary W. Pruessing
President
ExxonMobil Pipeline Company, LP
800 Bell Street
Room 3180H
Houston, TX 77002

Dear Mr. Pruessing: **CPF No. 4-2013-5027**

On March 29, 2013, the Pegasus Pipeline ruptured near the town of Mayflower, Arkansas releasing an estimated 5,000 barrels of crude oil in a high consequence area (HCA)[1]. As a result of this accident and pursuant to Chapter 601 of 49 United States Code, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) investigated the accident and inspected operation and maintenance records and procedures related to the Pegasus Pipeline, which is operated by ExxonMobil Pipeline Company (EMPCo)[2]. From this point, reference to "the operator" will refer to the assets involved in this release identified as Mobil Pipeline operated by ExxonMobil Pipeline Company.

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

1. § 195.452 Pipeline integrity management in high consequence areas.
(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?

[1] This estimate may increase when the pipeline is restarted and an actual measurement of the spill volume can be calculated.
[2] The Pegasus Pipeline is owned by Mobil Pipeline Company and operated by EMPCO.

(1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). <u>An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment</u>. The factors an operator must consider include, but are not limited to:

(i) <u>Results of the previous integrity assessment</u>, defect type and size that the assessment method can detect, and defect growth rate;
(ii) Pipe size, material, <u>manufacturing information</u>, coating type and condition, and seam type;
(iii) Leak history, repair history and cathodic protection history;
(iv) Product transported;
(v) Operating stress level;
(vi) Existing or projected activities in the area;
(vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
(viii) geo-technical hazards; and
(ix) Physical support of the segment such as by a cable suspension bridge.

The integrity assessment schedule established by the operator did not include consideration of certain manufacturing information in their determination of risk factors as required. Specifically, the operator failed to include the susceptibility of its Youngstown, pre-1970 low frequency electric-resistance welded (ERW) pipe seam to failures as a risk factor for the Pegasus Pipeline System in the implementation of its integrity management program.

The operator experienced multiple hydrostatic test failures on the Pegasus Pipeline as a result of ERW long seam failures in 1991 hydrotesting and subsequent 2005–2006 hydrotesting. The pipe manufacturing information, fracture toughness, and hydrostatic testing failure history of the Youngstown pre-1970 low frequency ERW pipe in the Patoka to Corsicana segments of the Pegasus Pipeline provided more than adequate information for the pipe to be considered susceptible to seam failure. Further, the operator did not present an acceptable engineering analysis to PHMSA to demonstrate that the pre-1970 ERW pipe in the Pegasus Pipeline was not susceptible to seam failure.

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

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

(3) Assessment intervals. An operator must establish five-year intervals, not to exceed 68 months, 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.

The operator failed to establish a five-year re-assessment interval for the Patoka to Corsicana segment of the Pegasus Pipeline after the hydrostatic test of 2005 and 2006 identified a susceptibility to seam failures. The operator failed to consider all risk factors for establishing an assessment schedule for continual integrity assessments when they did not consider the pipeline's manufacture and results of the previous integrity assessments to conclude that the pipeline was susceptible to seam failures. The next assessment was performed in 2012 and 2013 using a TFI tool.

The operator performed an inspection using a TFI tool in a series of four tool runs that began in July 2012 and was completed on February 6, 2013, on the Conway to Corsicana portion of the system. The baseline assessments (hydrostatic tests) were performed in 2005 and 2006. Therefore, this re-assessment was more than 68 months after the baseline assessments were performed, and exceeded the maximum re-assessment intervals required by 195.452(j)(3).

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

(b) ***What program and practices must operators use to manage pipeline integrity?*** **Each operator of a pipeline covered by this section must:**

(5) Implement and follow the program.

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

(4) Variance from the 5-year intervals in limited situations-

(i) Engineering basis. An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

The operator failed to follow its procedure 5.1 (4) (Continual Evaluation and Assessment Process) for a variance from the five year interval to extend the time frame for conducting its continual assessment of the Conway to Corsicana segment of the Pegasus Pipeline and failed to notify PHMSA. The operator extended the inspection timing from "prior to 12/31/2011" to "prior to 12/31/2012," and again from 12/31/2012 to 2/6/2013 without providing notice to PHMSA at least 270 days prior to the end of the five year period which expired in 2011, five-years (NTE 68 months) from the date of the baseline hydrotest.

The operator's procedures for Continual Evaluation and Assessment Process are included in the IMP. Section 5 of the procedures includes the rule requirements for establishing assessment intervals in accordance with §195.452(j)(3). The procedures included the requirements for a variance from the 5-year intervals in limited situations. Variance from the five-year reassessment interval was allowed when the operator was able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The operator's procedure required notification to PHMSA 270 days before the end of the five-year (or less) interval of the justification for a longer interval and propose an alternative interval.

PHMSA did not receive a notice, or a request for extension from the operator to extend the interval beyond five years for the Conway to Corsicana segment of the Pegasus Pipeline assessment with a method capable of assessing seams in ERW pipe.

4. §195.452 Pipeline integrity management in high consequence areas.

> **(e)** ***What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?*** **(1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section. An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment.**
>
> (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*
>
> (3) Assessment intervals. An operator must establish five-year intervals, not to exceed 68 months, 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.

The operator's integrity assessment schedule failed to prioritize pipeline segments to re-assess the pipe that posed the highest risk to the high consequence areas before re-assessing lower risk segments. The operator failed to prioritize the Corsicana to Conway segment higher than the Patoka to Conway segment of the Pegasus Pipeline for reassessment related to manufacturing flaws, and seam failure susceptibility.

The Corsicana to Conway segment had more hydrotest failures in 2006 than the Conway to Patoka segment, including the test failures that were at lower pressures than previous test levels. This segment had all of the seam failures during the 1991 hydrotesting. This segment experienced an in-service ERW seam leak, and had more miles of Youngstown ERW pipe. The Conway to Foreman segment had the most actionable anomalies after the baseline assessment in 1999. The operator's fatigue analyses resulted in the shortest required reinspection interval on the Conway to Corsicana segment at 7.4 years, and the shortest reinspection interval on the Patoka to Conway segment was more than 9 years.

Additionally, there were more sensitive receptors in the Corsicana to Conway segment of the pipeline, including the Lake Maumelle Watershed. However, the operator's decision to perform the TFI Tool inspection on the Patoka to Conway segment first was not documented, and was not based upon appropriate risk considerations that would indicate the TFI run should have been performed on the Conway to Corsicana segment first.

5. §195.452 Pipeline integrity management in high consequence areas.

> **(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 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 conditions will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with §195.422 when making a repair.**

The operator failed to take prompt action to address all anomalous conditions on their pipeline. The operator failed to declare discovery of immediate repair conditions from information received in preliminary reports from the in-line inspection (ILI) vendor, and as a result, the operator treated "Immediate Conditions" as "Validation Digs" or "Confirmation Digs" and did not take appropriate actions for "Immediate Conditions."

Two examples of this are MP 164.051 and MP 142.394. Both sites were identified as immediate repairs from the preliminary report received from the vendor on August 9, 2010; however the operator did not identify them as immediate repairs until the sites were excavated and as a result, the operator's anomalous condition discovery process was carried out in a manner that was inconsistent with the regulatory requirement. For MP 164.051, the date of identification from the operator was identified 19 days after the vendor report on August 28, 2010, and for MP 142.394 several months after the report on January 6, 2011.

6. §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 failed to declare discovery within 180 days in four separate instances on the Pegasus Pipeline Patoka to Corsicana segments (2010, 2011, and 2013) despite the availability of adequate information in the vendor reports to make such determinations.

The following Table summarizes the relevant dates for the subject segments:

Patoka to Conway (2 Testable Segments)			
Action	Date	180 Day Deadline	Date of Actual Discovery
MFL-Combo Run	6/10/2010	12/7/2010	3/4/2011
TFI Tool Run	8/15/2010	2/11/2011	3/4/2011
Preliminary Report	7/10/2010		
Conway to Corsicana (2 Testable Segments)			
Action	Date	180 Day Deadline	Date of Actual Discovery
MFL-Combo Run	7/21/2010	1/17/2011	3/15/2011
TFI Tool Run	2/6/2013	8/5/2013	8/30/2013
Preliminary Report	8/23/2010		

7. §195.452 Pipeline integrity management in high consequence areas.

(b) ***What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:**

(5) Implement and follow the program.

(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).

The operator failed to follow its procedure, IMP Section 5.4, which requires risk assessments to be updated as changes occur, which includes potential threat changes. The operator did not follow their procedure when they extended the inspection timing of the Conway to Corsicana segment of the Pegasus Pipeline from "prior to 12/31/2011" to "prior to 12/31/2012," and again from 12/31/2012 to 2/6/2013 without revising the risk analyses that relied upon the inspection having been performed in the Summer of 2011, even though the inspection was not performed until February 6, 2013.

The operator's Operations Integrity Management Systems (OIMS) Element 2, Risk Assessment & Management requires in 2.4 that "Risk assessments are updated at specified intervals and as changes occur." Further, the operator's Integrity Management Program Section 5.4 requires annual review to determine if an updated risk assessment is required. Items that must be considered in the review include potential threat changes.

As a result of not updating the risk assessment, there were no Identified Threats on the Conway to Foreman Segment, as demonstrated by the two analyses that were performed in March 2011. The failure to identify an "Identified Threat" caused the integrity decisions to rely upon incorrect bases for the analyses that were carried out that rely upon identification of threats for EFRD analyses, additional preventive and Mitigative measures, and other risk reduction activities that may be deemed necessary to bring the risk to an acceptable level.

8. §195.402 Procedural manual for operations, maintenance, and emergencies.

(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

The operator failed to follow its Operations and Maintenance procedures by selectively using results of its Threat Identification and Risk Assessment Manual (TIARA) process in 2011 which resulted in the failure to properly characterize the risk of a release to the Lake Maumelle Watershed, and other HCAs in the Conway to Foreman segment of the pipeline. This resulted in the failure to determine an "Identified Threat" related to Manufacturing existed on the segment, and failed to elevate the threat as required by OIMS and the TIARA processes for appropriate risk reduction activities in multiple integrity processes that rely upon the TIARA results as inputs to the processes for risk reduction activities.

9. §195.452 Pipeline integrity management in high consequence areas.

(b) ***What program and practices must operators use to manage pipeline integrity?*** **Each operator of a pipeline covered by this section must:**

(5) Implement and follow the program.

> (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.

The operator failed to follow its procedures for creating a Management of Change document for the merging of testable segments for their Pegasus Pipeline. The operator combined the previously identified four segments for the Patoka to Corsicana segment to two testable segments. The operator's procedures, OIMS Element 7.2 Corporate Expectation to perform an analysis of Operations Integrity Implications, required a Management of Change document to be created for a significant change as completed in this case to ensure undervaluation of the consequences of a change in its risk management program does not occur.

As a result of the change, the longer Testable Segments negatively impacted the TIARA risk assessments by masking higher threat intermediate segments (such as the Lake Maumelle Watershed and Mayflower populated areas) with the dilution of the risk scores that resulted from the increased length of the Testable Segment.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 3, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $2,659,200 as follows:

Item number	PENALTY
1	$737,200
2	$737,200
3	$ 56,100
4	$ 47,500
5	$ 56,100
6	$102,200
7	$ 70,500
8	$783,300
9	$ 69,100

Proposed Compliance Order

With respect to items 1, 2, 5, 6, and 8 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to the operator. 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. All material you submit in response to this enforcement action may be 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 4-2013-5027** 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 Proceeding

PROPOSED COMPLIANCE ORDER

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

1. In regard to Item Number 1 of the Notice; the operator's failure to consider pre-70 LF ERW pipe susceptible to seam failure, the operator shall modify its Integrity Management Plan (IMP) procedures addressing seam failure susceptibility analyses, seam integrity assessment plans, and threat modeling to ensure risks are adequately identified and assessment actions are carried out to address the specific nature of all pre-70 ERW pipe on any assets covered by the operator's IMP. In carrying out this Item, the operator shall complete at a minimum, the following actions:

a. Within 30 days of issuance of the Final Order, the operator shall prepare and submit to PHMSA a spreadsheet identifying all pre-70 ERW pipe operated under the operator's IMP for which PHMSA has jurisdiction.

b. Within 30 days of issuance of the Final Order, the operator shall identify and catalogue all IM processes used in the risk assessment and integrity decisions related to the determination of seam failure susceptibility, development of Seam Integrity Assessment Plans (SIAPs), and assessment of pre-70 ERW pipe. Upon completion of this list, it shall be submitted to PHMSA, SW Region.

c. Within 90 days of issuance of the Final Order, the operator shall review the risk scoring of pre-70 ERW pipe in its TIARA processes and incorporate enhancements to ensure that the risk levels attributed to segments deemed susceptible to seam failure receive appropriate heightened risk scores to ensure Identified Threats are not overlooked, and that the appropriate considerations are incorporated into the questionnaire used in the TIARA process for manufacturing threats. The risk analysis of pre-70 ERW pipe shall not be a relative ranking against other assets and will be conducted in a manner that ensures appropriate management review and approval of all integrity decisions for risk reduction actions related to pre-70 ERW pipe.

d. Within 120 days of issuance of the Final Order, the operator shall revise its Seam Failure Susceptibility Analysis (SFSA) Process to incorporate up to date knowledge and relevant results of the operator and industry learnings from failure analyses and research. The revised SFSA process shall be reviewed by a third party expert subject to PHMSA's approval to ensure adequate consideration of all relevant aspects of the management of pre-70 ERW pipe are incorporated into the SFSAs and resultant SIAPs.

e. Within 120 days of issuance of the Final Order, the operator shall revise its process for conducting crack growth analyses through pressure-cycle-fatigue modeling to ensure that appropriately conservative assumptions are used to develop re-inspection intervals and incorporate these practices into its Fatigue Analysis (FA) procedures. The revised FA process shall be reviewed by a third party expert subject to PHMSA's approval to ensure adequate consideration of all relevant aspects of the management of pre-70 ERW pipe are incorporated into the FAs and the resultant reassessment intervals for pipe subject to pressure-cycle-fatigue.

2. In regard to Item Number 2 of the Notice; the operator shall ensure that its procedures for assessment intervals clearly identify that all risk factors must be assessed within the regulatory timeframes, or less, based upon the appropriate engineering analyses, but in no case shall exceed 5 years, not to exceed 68 months as required by §195.452(j)(3).

3. In regard to Items Number 5 and 6 of the Notice; the operator shall revise its IM processes to ensure timely Discovery and interim Discovery for preliminary reports such that Immediate Repair Conditions are clearly identified regardless of the type of report provided by the vendor (ie., telephone call, spreadsheet, preliminary, final, Binder, etc.) and Discovery of the condition occurs. Revisions to the operator's processes shall address appropriateness of the manageable size of Testable Segments, to ensure timely response to integrity assessments and remedial actions.

4. In regard to Items Number Items Number 5 and 6 of the Notice; the operator shall revise its IM processes to ensure timely Discovery occurs no later than 180 days after completion of the assessment. The operator shall review its IM processes utilizing personnel (company or consultant) from outside of the IM group in accordance with its OIMs process of external audits to ensure an objective review of processes, past performance, and recommended enhancements to facilitate timely discovery is achieved, which will also result in compliance with the federal pipeline safety regulations. The review shall specifically examine the process outlined in the operator's IMP process flow chart depicted by User's Guide Figure 4.2: Integrity Assessment & Repair Flow Chart. The review shall specifically address the types of defects for which TFI, UT, EMAT tools or hydrostatic testing shall be utilized. The audit shall result in a report of findings and recommended enhancements submitted to PHMSA, and incorporated into the revision of the operator's IMP processes.

5. In regard to Item Numbers Items Number 5 and 6 of the Notice; the operator shall conduct an internal investigation of its OIMS, IMP and interrelated management processes' failure to adequately identify and assess the risk and take appropriate risk reduction activities to address the threat of potential seam failures on the Pegasus Pipeline. The investigation shall be led by ExxonMobil Company personnel, with risk assessment, HAZOP and Safety Management System experience from outside of the organization who are qualified to perform such assessments in accordance with OIMS 2A requirements. The operator may use a qualified consultant or contractor, subject to the approval of PHMSA in lieu of ExxonMobil Company personnel. A summary of the findings and resultant recommendations shall be shared with PHMSA, and incorporated into the revisions carried out in response to the Final Order. The investigation can be integrated with the audit required in Item 4 of this Order. The operator shall submit a Scope for both Items 4 and 5 of this Order for PHMSA's approval prior to commencing the audit and/or investigation.

6. In regard to Item Number 8 of the Notice; the operator shall revise its Risk Assessment processes to ensure appropriate training, interdisciplinary participation and management level review and oversight are carried out to ensure that the integrity decisions that affect the final risk scores are not manipulated, or that processes are not circumvented, and that risk assessment assumptions are appropriately conservative. The revised process shall ensure that checks and balances are integrated into the process to avoid conflicting budget goals with integrity

prioritization decisions. The revised process shall include revisions to change management processes to ensure a feedback loop to any previous risk decisions requires risk assessments be updated as changes occur. The results of Items 4 and 5 of this Order shall be incorporated into the process improvements carried out under this Item.

7. In regard to Item Number 8 of the Notice; the operator shall revise its Risk Assessment and Data Integration processes to ensure that Identified Threats are not discounted, and greater reliance is placed upon knowledge of the asset, its previous assessments and operating history over the TIARA results in the IM processes. The results of Items 4 and 5 of this Order shall be incorporated into the process improvements carried out under this Item.

8. The operator must complete and submit all documentation for actions completed under Items 3 through 7 of this Compliance Order (CO) according to the following schedule:

a. CO Item 3 shall be completed within 60 days of issuance of the Final Order
b. CO Items 4 and 5 of this Compliance Order shall have a scope of work and proposed schedule submitted to PHMSA, SW Region for review and approval no later than 90 days after issuance of the Final Order.
c. CO Items 6 and 7 shall be completed within 60 days of Items 4 and 5.

9. It is requested (not mandated) that the operator 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.