NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

February 15, 2013

Mr. Steve Pankhurst
President
BP Pipelines (North America) Inc.
150 West Warrenville Road
Naperville, Illinois 60563

CPF 3-2013-5005M

Dear Mr. Pankhurst:

Between August 2 and January 18, 2011, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Minnesota Office of Pipeline Safety, and Washington Utilities and Transportation Commission, pursuant to Chapter 601 of 49 United States Code inspected BP Pipelines (North America) Inc. (BP) procedures for Operations and Maintenance, Operator Qualification, Public Awareness, Damage Prevention, and Integrity Management through an Integrated Inspection process in BP's offices and field locations in Illinois, Iowa, Missouri, New Jersey, Ohio, Oklahoma, Oregon, Texas, and Washington. The systems included in the inspection were BP Pipeline (North America) Inc., Olympic Pipeline, Amoco Pipeline, BP USFO/Logistics, Main Pass Oil Gathering, BP Oil Pipeline, Tri-States NGL Pipeline and Black Lake Pipe Line.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within BP's Operations and Maintenance (O&M) procedures, as described in Items 1- 12 below:

1. **§ 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:**

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§195.432 Breakout tanks.
(b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).

BP did not adequately describe the Engineering Review (ER) performed on each breakout tank inspection report that addressed the physical integrity of an in-service atmospheric tank. The ER evaluates each API 653 tank inspection report and makes determination on actions to be taken by BP to address findings that were recommended in the report. When the ER does not concur with the qualified inspector's findings and recommendations, BP needs to amend their procedures to describe how the ER's justification is determined.

2. **§ 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:**

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§ 195.402(c)(7) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the limits prescribed by paragraph §195.406, consider the hazardous liquid or carbon dioxide in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices.

BP did not reference their second manual, OMER II, which has specific procedures for Starting Up and Shutting Down each pump station on their system. BP needs to reference the OMER II manual when addressing the start up and shut down of each pipeline pump station.

3. **§195.442 Damage prevention program.**

(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary markings to be provided and how to identify the markings.

BP procedures did not adequately address marking requirements. The existing BP procedures indicated that pictures should be taken of each pipeline location marked or verify that the excavators were in the correct spot, in accordance with the APWA-ULCC Standard. A review of several BP operational units indicated that BP personnel did not consistently capture the necessary information. BP needs to amend their procedures to ensure and describe how supporting documentation is taken at each location with a methodology to verify that excavators are at the correct location prior to excavation.

4. § 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§ 195.561 When must I inspect pipe coating used for external corrosion control?
(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

BP did not require the use of electronic inspection as a coating inspection tool for sections of coating on pipeline sections shorter than forty-five feet in length. BP's procedure specifically stated that repaired section less than 45 feet does not require jeeping, i.e., electronic coating inspection. BP needs to amend the procedure to require adequate inspection, including the use of an electronic instrument holiday detector, of any length of pipe coating that has been applied.

5. § 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?
(c) Maintenance. You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with Sec. 195.571.

BP's maintenance procedure for test leads did not require a timely repair of each test lead when warranted. The BP specification allowed one (1) calendar year after discovery of a maintenance issue for the repair to be completed. BP needs to amend the procedure to require a timely repair of test leads to ensure the ability to take measurements of cathodic protection exists at each test station.

6. § 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§ 195.571 What criteria must I use to determine the adequacy of cathodic protection?

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard RP 0169 (incorporated by reference, see §195.3).

BP's established criteria for determining adequacy of cathodic protection with reference to stress corrosion cracking (SCC), was not adequate. BP states two criteria, -770mv and 100mv shift, that are used for determining protection for preventing SCC. However, it is unclear how the –770mv criteria was established. BP procedures need to fully describe the use of 100mv shift and provide justification for the use of –770mv in relation to SCC.

7. § 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§ 195.573 What must I do to monitor external corrosion control?
(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column. Interference bond whose failure would jeopardize structural protection, at least six times each calendar year, but with intervals not exceeding 2 ½ months. Other interference bonds, at least once each calendar year, but with intervals not exceeding 15 months.

BP's procedure did not address other (non-critical) interference bonds and their required inspection. BP needs to amend their procedure to address other interference bonds and the inspection of those devices once each calendar year not to exceed 15 months.

8. **§ 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:**

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§ 195.573 What must I do to monitor external corrosion control?
(e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

a) Except for annual surveys, BP's procedure did not include a proper corrective action for identified deficiencies in corrosion control. BP needs to amend their procedure to include all identified deficiencies and the corrective action to be taken and a timeline for action.

b) BPs procedure pertaining to close interval surveys (CIS) did not meet the requirements of BP's Re-Assessment Interval Determination (RAID) program for integrity management. BP's definition and use of "immediate" in terms of making determinations of "Areas of Concern" after a successful completion of a CIS was not timely. BP allows 643 days to make determination of "Areas of Concern," which is not consistent with the RAID program. BP needs to amend their procedure to address timely determination consistent with the RAID program.

9. **§ 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:**

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

§ 195.579 What must I do to mitigate internal corrosion?
(c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

BP did not include the inspection of the coupons cut and retrieved during hot tapping process for internal corrosion in their procedure. BP needs to amend their procedure to include the inspection of coupons for evidence of internal corrosion cut and retrieved during a hot tapping process.

10. § 195.402(c) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(13) Periodically reviewing the work done by operator to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

BP's procedure did not adequately describe how deficiencies found during the reviews were documented and what corrective actions were taken to address them. BP needs to amend their procedure to capture the findings of the review and any actions taken to correct deficiencies.

11. § 195.404 Maps and Records.

(b) Each operator shall maintain for at least 3 years daily operating records that indicate-
(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

BP's procedure for keeping records of actions taken on abnormal operations (UAG - BP acronym) reports from the BP Control Center and field were not definitive. Actions taken by personnel in the field were not consistently captured in the reports. BP needs to amend their procedure to ensure actions taken in the field to review and correct (when necessary) the UAG are documented.

12. §195.569 Do I have to examine exposed portions of buried pipelines?

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

BP's procedure addressing the repair of findings, including SCC, did not adequately address repair criteria. The procedure did not address the extent of pipe that should be exposed upstream or downstream once SCC has been found. BP needs to amend their procedure to address what area of a pipeline should be exposed and investigated once SCC has been identified.

On the basis of the inspection, PHMSA had identified apparent inadequacies within BP's Integrity Management Program (IMP) as described in Items 13 - 19 below:

13. § 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:

(4) Include in the program a framework that –

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

§ 195.452 (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:
(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

BP's procedure did not adequately address all the requirements for a preventive and mitigative (P&M) measures program per §195.452(i). The procedure did not include the requirements for documentation, frequency of documenting and the retention period of each document. BP needs to amend their procedure to address P&M implementation frequency requirements and the documentation requirements for the P&M program.

14. § 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:

(1) A process for identifying which pipeline segments could affect a high consequence area;

BP's procedure for identifying high consequence areas (HCAs) did not provide adequate detail. The procedure did not identify exactly who identifies new or modified HCAs, when they will identify new or modified HCAs, or what training they will receive to identify new or modified HCAs, etc. In addition, the procedure did not address other sources outside of the National Pipeline Mapping System. The procedure only describes how they report new or modified HCAs but has no mechanism to ensure all areas of the regulated pipelines are reviewed on some defined frequency. BP needs to amend their procedure to adequately identify which pipeline segments could affect a high consequence area.

15. § 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:

(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

BP's procedure for integrating all available information about the integrity of the entire pipeline is inadequate. BP's procedure only allowed a "High-High" risk ranking to be designated on areas where stress corrosion cracking (SCC) had been previously found. BP needs to amend their procedure to ensure risk ranking is applied correctly when SCC is initially identified.

16. § 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);

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

(4) Special requirements for scheduling remediation

(iv) Other conditions. In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

BP's procedure for remedial action did not address "other conditions" that may be identified by an integrity assessment or information analysis that could impair the integrity of the pipeline. BP needs to amend their procedure to address "other conditions" that may be identified by an integrity assessment or information analysis that could impair the integrity of the pipeline. The procedure must address the timeliness of performing those required remedial actions.

17. § 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:

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

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

(5) Assessment methods. 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.

BP's procedure for continuous evaluation and assessment was inadequate. BP did not address utilizing different types of assessment methods when new or different information becomes available. BP needs to amend their procedure to include other evaluation and assessment methods when information or conditions warrant change.

18. § 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:

(7) Methods to measure the program's effectiveness (see paragraph (k) of this section:

a. BP's procedure for implementing a program to manage the pipeline integrity did not adequately define the roles of management. BP needs to amend their procedure to have a formal mechanism for review and approval of the IM/OM Team's recommendations.

b. BP's procedure to measure program effectiveness was inadequate. The operator's "Program Measures Procedure #P-195.452.f7" pages 1 thru 2 of 2 did not address the frequency for using the required forms as indicated on page 1 of 2. The same procedure requires that the DOT Compliance Team develop an IMP Annual Summary Report and issue it to the "USPL Leadership Team by the end of January of the succeeding year." The procedure needs to be more definitive and make provisions for data collection and tracking the outcome of actions adopted from the review of the report, with both justifications for the decisions made and processes to track the implementation of the actions.

19. § 195.452 Pipeline integrity management in high consequence areas.

(l) What records must be kept? (1) An operator must maintain for review during an inspection:

(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

BP's procedure addressing records that must be kept was inadequate. BP did not clearly describe which records must be retained and the time period that records must be retained. BP's integrity management procedures must clearly define records retention requirements. In order for the operator to ensure data is available in the event of an inspection and that documents exist to support the decisions and analyses, the records will need to be maintained for the life of the pipeline. These records would include any modifications, justifications, variances, deviations, and P&M measures taken.

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 30 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.

It is requested that BP Pipelines (North America) Inc. maintain documentation of the safety improvement costs associated with fulfilling this Notice of Amendment (preparation/revision of plans, procedures) and submit the total to David Barrett, Director, Central Region, Pipeline and Hazardous Materials Safety Administration. In correspondence concerning this matter, please refer to **CPF 3-2013-5005M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

David Barrett
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

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