U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 26, 2007

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Mr. Darren C. Jones
Vice President, Commercial Assets
ATO 2100
ConocoPhillips Alaska, Inc. (CPAI)
700 G Street
Anchorage, AK 99510-0360

CPF 5-2007-5019M

Dear Mr. Jones:

On November 14 to 16, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your procedures for Integrity Management and various Part 195 requirements in Anchorage, Alaska. It was noted that segment identification for new High Consequence Areas (HCA) has a start date May of 2006 when CPAI determined the PHMSA position related to work camps and an Unusually Sensitive Area (USA) (spectacled eiders) being considered HCAs.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within CPAI's plans or procedures, as described below:

1. **§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section)**
   §195.452 (h) (2) *Discovery of a 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.

ConocoPhillips Alaska, Inc. (CPAI) considers a tool tolerance of 10% on the "immediate" through-wall anomalies. An analogous tolerance is not applied to the 180-day conditions.

2. **§195.452 (h) (1)** ***General requirements.*** **An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure 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.**

   §195.452 (h) (3) ***Schedule for evaluation and remediation.*** **An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation.... the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure**

   §195.452 (h) (4) ***Special requirements for scheduling remediation. Immediate repair conditions....*** **To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4....**

   ConocoPhillips Alaska, Inc.'s (CPAI) Integrity Management (IM) manual stated the following:

   > ***"Section 7.11 Temporary Operating Pressure Reduction:***
   >
   > ***7.11.1 Previous Maximum Operating Pressures***
   >
   > *To meet temporary operating pressure reduction requirements, CPAI depressurizes the defect location to a maximum of 75% of the highest operating pressure actually experienced within the two months preceding the inspection until additional engineering analysis is completed. The Field Mechanical/Piping Engineer completes the analysis within one week of discovery; at which time either a repair will be completed, the line shut-in and de-pressurized, or a longer-term operating strategy established by the Engineering and Corrosion and Pipeline Operations Supervisors.*
   >
   > *** *"Immediate" pressure reduction therefore taken as 7 days."*

   The Section 7.11.1 of your IM manual indicated that it will take seven days to implement a pressure reduction in response to "immediate" repair conditions. While "immediate" has not been defined by PHMSA, a nominal one-week response time is excessive for responding to this type of serious integrity condition.

3. **§195.452(e)** ***What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....***

   §195.452(i)(2) ***Risk analysis criteria.*** **In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....**

   ConocoPhillips Alaska, Inc.'s (CPAI) Integrity Management (IM) manual stated the following:

   > ***"List of Risk Factors from IM Plan:***
   >
   > ***Section 5.6.2, DATA GATHERING, REVIEW AND INTEGRATION***
   >
   > *The second risk assessment component involves gathering all pertinent data to characterize individual pipeline segments and the potential threats of a release to the HCAs. The IMP Coordinator gathers relevant information pertaining to the design, operation, maintenance, operating history, corrosion program, surveillance and specific failures and concerns. Specific information includes: CPAI incident reports (TapRoot), spill reports, vehicular accidents in the pipeline right-of-way, third party damage, corrosion data (inspections, coupons, S&W reports, etc), product characteristics, and management of change. Sources include operating personnel, documentation, and third party knowledge.*
   >
   > *Previously unrecognized risks are identified during the data integration meeting conducted by the Kuparuk Corrosion Team as described in the Kuparuk Corrosion Team Desktop Guideline (KCT Guideline), DOT Lines Data Integration. These previously unrecognized risks are reviewed and revised by the SMET and incorporated into the risk assessment as necessary so the index model adequately addresses all risks to the pipeline."*

   CPAI's Integrity Management program does not include all risk factors (e.g., "seam type," "manufacturing information") in the risk analysis model and/or the basis for exclusion is not documented.

4. **§195.452(e)** ***What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....***

   §195.452(f) 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);

   §195.452(g) ***What is an information analysis?*** **In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the**

consequences of a failure

§195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: ....

ConocoPhillips Alaska, Inc.'s (CPAI) Integrity Management (IM) manual stated the following:

> ***"Section 5.6.3, Risk Assessment:***
>
> *The itemization of the events potentially leading to a failure is categorized into four indices corresponding to areas having historically resulted in pipeline failures. The four indices are:*
>
> 1. ***Third Party Damage Index:*** *Examines the potential of harm from activities performed by someone other than the pipeline operating personnel.*
> 2. ***Corrosion Index:*** *Examines the type of corrosion plan in use and gives credit based on the potential for atmospheric corrosion, internal corrosion and buried metal corrosion.*
> 3. ***Design Index:*** *Examines how well the design process was performed and takes into account whether the pipeline is operating at pressure and flows below the design point.*
> 4. ***Incorrect Operations Index:*** *Examines the actual operation of the pipeline system by looking at operations, maintenance, construction and the design process. This index is the most subjective as it relies, in part, on operating personnel judgments.*
>
> *The Leak Impact Factor determines the consequence by examining the product characteristics, line pipe location, spill volume, and the affect of a leak condition. Each index has a score between 0 and 100 added together to provide an Index Sum. This Index Sum, divided by the Leak Impact Factor, provides a Relative Risk score (from 0 to 2000). A lower risk score indicates a higher risk. Figure 5-1, The Muhlbauer Model Diagram, illustrates the evaluation process applied to each pipeline segment."*
>
> **** All for major indices weighted equally (original Muhlbauer default)."*

The major risk indices in the modified Muhlbauer model – Design, Corrosion, Third Party, and Incorrect Operation – were weighted equally (default Muhlbauer model values). This is not reflective of CPAI's actual risk profile on your pipeline system (e.g., corrosion threats is not equal to third party damage threats for the CPAI lines), and should be justified.

5. **§195.452 (f) *What are the elements of an integrity management program?***

   (6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph of this section)

§195.452(i) ***What preventive and mitigative measures must an operator take to protect the high consequence area?*****(1)** ***General requirements.*** **An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.**

ConocoPhillips Alaska, Inc.'s (CPAI) Integrity Management (IM) manual stated the following:

> ***"Section 9.11.1, "Effectiveness Evaluation":***
>
> *When sufficient additional objective data, such as that prescribed in paragraph 195.452(g) and relevant to the North Slope Pipelines is located that may affect the outcome and corresponding rankings or following an actual unplanned product release the IMP Coordinator works with a SMET to revise the risk assessment and measures profile, and evaluate the effectiveness of preventive and mitigative measures.*
>
> *At a minimum, the previous measures evaluation will be reviewed, and revised as necessary, during the IMP annual review following the completion of each pipeline assessment and any associated repairs or mitigation activities. New information, received from activities such as pipeline assessments, modifications, or repairs; and additional operating modifications and experience is incorporated into the analysis, priorities are adjusted based on the outcomes, and the IMP is revised to reflect the current status of pipeline integrity management utilizing this process in conjunction with those described in Section 12, Change Management, and Section 13, Program Review."*

A maximum interval or other criteria to initiate the re-evaluation of Preventive and Mitigative (P&M) measures was not well defined. The present "criteria" for re-evaluation includes a significant change in the line configuration, operation, risk assessment change, etc... P&M measures were evaluated for the first time in 2004; however, CPAI revised the risk model in 2005 and did not re-evaluate the P&M measures of the revised risk results.

7. **§195.452 (f) 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?*** **(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 of this section).

While CPAI did establish the methods of integrating IM data; however, the IM program does not include an explicit "Periodic Evaluation" process as required by 195.452(j)(2).

Meanwhile, the data integration meeting is conducted every six months and an annual review is conducted to determine if risk analysis needs to be revised. It appears that CPAI did not include all of the required periodic evaluation considerations.

7. **§195.583 What must I do to monitor atmospheric corrosion control?**
   (a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore..................................	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Offshore.................................	At least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §195.581.

CPAI's method of atmospheric corrosion control did not comply with 195.583 requirements (modified ECDA not doing entire line condition). A waiver must be submitted to PHMSA to support the current approach. The presentation of the activities conducted in place of in-line inspection (ILI) or hydrotest were discussed at length. In general, your adaptation of the ECDA for aboveground piping has merit but does not appear to meet the requirements of 195.583 especially in the areas of pipe supports and under thermal insulation.

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 60 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.

In correspondence concerning this matter, please refer to **CPF 5-2007-5019M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

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

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

cc: PHP-60 Compliance Registry
PHP-500 B. Hansen (#118171)