DEC 29 2011

Mr. Eric Amundsen
Vice President and Chief Asset Integrity Officer
Panhandle Eastern Pipeline Company
5444 Westheimer Road
Houston, TX 77056

Re: CPF No. 2-2010-1009M

Dear Mr. Amundsen:

Enclosed is the Order Directing Amendment issued by the Associate Administrator for Pipeline Safety in the above-referenced case. It makes a finding of inadequate procedures and requires that you amend your written integrity management program. When the terms of the Order are completed, as determined by the Director, Southern Region, this enforcement action will be closed. Your receipt of the Order Directing Amendment constitutes service of that document under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Wayne T. Lemoi, Director, Southern Region, OPS

CERTIFIED MAIL – RETURN RECEIPT REQUESTED [_71791000164203039955___]

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
Panhandle Energy,	)	**CPF No. 2-2010-1009M**
Respondent.	)	

ORDER DIRECTING AMENDMENT

On April 12-16 and April 26-30, 2010 pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Office of Pipeline Safety (OPS) inspected Respondent's written gas integrity management program (IMP) procedures in Respondent's Houston, Texas office. Panhandle Energy (Panhandle) operates three gas pipeline systems, consisting of over 10,000 miles of transmission lines: Panhandle Eastern Pipe Line Company, Trunkline Gas Company, and Sea Robin Pipeline Company.[1]

As a result of the inspection, the Director, Southern Region, OPS issued to Respondent, by letter dated August 18, 2010, a Notice of Amendment (NOA). The Notice alleged inadequacies in Respondent's integrity management program and proposed, in accordance with 49 C.F.R. § 190.237, that Respondent amend its integrity management procedures.

Panhandle Energy responded to the NOA on September 17, 2010 ("Response") and agreed to amend its procedures for the items 1, 2A, 3, 4, and 6. Respondent contested the two remaining items in the NOA, 2B and 5. Respondent requested a hearing for these contested items in accordance with 49 C.F.R. § 190.211. A hearing was held via telephone conference on March 3, 2011, with an attorney from the Office of Chief Counsel, PHMSA, presiding. Respondent was represented by counsel during the hearing. Respondent had a court reporter record the hearing, and the court reporter provided a final transcript of the hearing to all parties approximately one week afterwards. Respondent submitted a post hearing response ("Closing") on May 2, 2011.

FINDINGS OF INADEQUATE PROCEDURE

The Notice identified the following apparent inadequacies in Respondent's plans or procedures:

[1] http://www.panhandleenergy.com/serv_trans.asp (last accessed 12/9/2011).

Item 2B: The Notice alleged that Respondent's gas IMP failed to adequately address 49 C.F.R. § 192.921(a)(1), which states:

> **§ 192.921 How is the baseline assessment to be conducted?**
> (a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 192.917).
> (1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

The NOA alleged that Respondent's IMP assessment method procedures did not require the consideration of internal in-line inspection (ILI) tool tolerances to effectively address pipeline threats. Also, the NOA alleged that Respondent's procedures lacked specific requirements for comparing recent ILI runs to previous ILI runs for monitoring anomalies.

In its Response and during the hearing, Respondent stated that its IMP procedures satisfied the cited regulation. Respondent stated that it considers the condition of the specific pipeline section at the time of ILI contract bidding and considers the tool and performance specifications submitted by vendors prior to awarding ILI contracts.[2] Accordingly, Panhandle's "Inline Metal Loss Inspection, Tool Specification" procedure requires that ILI vendors provide tool tolerance information; the procedure also contains tool tolerance minimum requirements.[3] Panhandle further argued in its Response that Part 192, subpart O "does not require, much less define tolerance."[4] Respondent also stated during the hearing that its procedures required consideration of previous runs and monitored conditions between subsequent inline inspections.[5]

PHMSA began its hearing presentation by acknowledging that Panhandle specifies tool tolerance when it runs an ILI tool by ensuring that the tool performed to within 10% or 15% accuracy by comparing reported indications by the tool to the actual condition of the excavated pipe. PHMSA clarified that its concern was not simply ensuring that a tool performed within the expected accuracy range. Rather, PHMSA pointed to Respondent's lack of procedures requiring additional engineering analysis on anomalies that are not reported by the tool as defects requiring immediate repair or remediation. PHMSA explained that given that the ILI tool that Respondent uses is generally accurate within 10% of the anomaly depth 80% of the time, the tool will provide less accurate results 20% of the time. Therefore, PHMSA's concern is that the size or depth of some anomalies may be underreported, even when a tool is performing as required. This could allow for defects that threaten the integrity of the pipeline to be identified as less serious anomalies. Therefore, in order to accurately "assess the integrity of the line pipe," as required in the regulation, the 20% margin of error must be accounted for.

[2] "Panhandle Energy Response to NOA CPF 2-20101009M, September 17, 2010" (hereinafter Response), at 1.
[3] "Inline Metal Loss Inspection, Tool Specification," Sections 3.2 and 3.5.
[4] Response at 4.
[5] Hearing Transcript, page. 13, lines 8-12, dated March 3, 2011.

PHMSA explained that a pipeline operator can account for the lack of certainty in the tool in various ways. Some operators simply add or subtract a vendor-supplied accuracy specification to the reported depth of metal loss, although PHMSA recognized that Panhandle does not agree with this approach. PHMSA pointed out that another way to achieve this is by conducting a probability of exceedance analysis.[6]

To further support its position and to counter Respondent's argument that Item 2B is not supported by the regulation, PHMSA cited guidance document Gas IM FAQ 68, that it issued to assist pipeline operators in meeting the requirement in §192.921(a) that it "select the method or methods *best suited* to address the threats identified to the covered segment." (emphasis added) Gas IM FAQ 68 states, in part,

> "Immediate repair conditions may not be discovered (because the ILI tool "under called" the defect) even if the tool functioned within its published accuracy specifications, if tool accuracy is not considered. . . . This does not necessarily mean simply adding the vendor-supplied accuracy specification to reported depth of metal loss indications. Several sources of data may be used, in conjunction with vendor-supplied tool specifications, to characterize pipeline defects. These include results of previous excavations, confirmation digs, results of concurrent inspections and comparison to prior inspections."[7]

Respondent could not identify language in its IMP that required the consideration of tool tolerances as described in FAQ 68. Instead, Respondent stated that it did perform this type of analysis, but the analysis was not documented in its procedures. Respondent then agreed to add language to its IMP that would document this analysis.[8] However, the documentation that Respondent submitted after the hearing ("Closing") stated, "PHMSA agreed in the hearing that adding internal processes and procedures outlined in A through L of PEs initial Hearing Document to PE's SOP's would satisfy Pumas' concerns."[9] This statement is untrue, as PHMSA specifically stated in the hearing that Panhandle's Hearing Document was not responsive to PHMSA's concerns.[10] Furthermore, the updates to the gas IMP that Panhandle submitted revised the development of unity plots, which compare ILI tool performance to the tool specification. The discussion at the hearing (as memorialized in the transcript) established that measuring accuracy of the ILI tool was not at issue.[11] Contrary to Panhandle's assurances at the hearing, it did not develop or include procedures in its IMP to analyze anomalies with additional information from previous inspections and excavations, concurrent inspections, confirmation

[6] Hearing Transcript, page 17, lines 9-14.
[7] Gas IM FAQ 68, available at: http://primis.phmsa.dot.gov/gasimp/faqlist.gim
[8] Hearing Transcript, page 22, lines 10 -16 and page 25, lines 5-9.
[9] Closing, May, 2 2011, at 1.
[10] Hearing Transcript, page 15, lines 22-25 ("And so I think in terms of Panhandle's response, I guess, I think item D under the tool tolerance discussion is really the only item in their response that specifically addresses what this issue is related to.") Item D of Panhandle's is a comment and not part of its procedure.
[11] Hearing Transcript, page 16, line 26 and page 17, lines 1 – 5. ("I fully realize that they are actually specifying the tool tolerance when they do an inline inspection contract and that they are doing a plot to determine whether or not the tool meets those specifications, comparing the reported indications to the ones that they excavate and actually examine.")

digs, or application of the vendor-supplied accuracy specification to investigate whether the tool under reported them.

Accordingly, I find that Respondent's gas IMP fails to include procedures that ensure a complete assessment of the integrity of each covered segment because it does not require analysis to account for an ILI tool's allowed margin of error. This incomplete assessment prevents Respondent from "select[ing] methods best suited to address the threats identified to the covered segment." Therefore, I find that Respondent's procedure for ensuring tool accuracy is inadequate to ensure safe operation of its pipeline system.

Item 5: The Notice alleged that Respondent's gas IMP failed to adequately address 49 C.F.R. §§ 192.911(e) and 192.933(b) and (d)(1), which state:

> **§ 192.911 What are the elements of an integrity management program?**
>
> An operator's initial integrity management program begins with a framework (see § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see § 192.7) for more detailed information on the listed element.) (1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.
>
> (a) . . . .
>
> (e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.
>
> **§ 192.933 What actions must be taken to address integrity issues?**
>
> (b) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.
>
> (d) *Special requirements for scheduling remediation*.--(1) *Immediate repair conditions*. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these

> conditions. An operator must treat the following conditions as immediate repair conditions:
>
> (i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.
>
> (ii) A dent that has any indication of metal loss, cracking or a stress riser.
>
> (iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

The Notice alleged that Respondent's procedure SOP J.14 entitled, "*In-Line Inspection: Data Integration, Analysis, and Response*" is inadequate because it does not consider anomalies exceeding 80% wall loss as an immediate repair condition. In its Response and at the hearing, Respondent argued that § 192.933(d)(1) is a performance- based regulation and leaves the decision to repair defects of 80% or greater wall loss to the operator. In support of this, Respondent pointed to the language in § 192.933(d)(1)(iii), which relies on the judgment of the operator or its contractor. It also explained that it uses the rupture pressure ratio (RPR) methodology, as described in B31.83 (2009).[12] This method requires the repair of anomalies with a depth equal to or greater than 80% of wall thickness only when the RPR is equal to or less than 1.39. Respondent emphasized that its methodology focuses on preventing ruptures. It admitted that some leaks on short, deep flaws could occur, but Panhandle maintained that their methodology is consistent with both subpart of O and B31G because the focus of those standards is to prevent ruptures, not necessarily leaks.[13]

In the hearing, PHMSA disagreed with Respondent's evaluation and remediation methods and arguments. First, it argued that § 192.933(d) is a prescriptive regulation, not performance based. It recognized that § 192.933(d) references ASME/ANSI B31G, but it clarified that the edition incorporated by reference at § 192.7 is the B31G 1991 edition, which was reaffirmed in 2004. Unlike the 2009 edition, the 1991 edition requires that a corroded area with a depth of greater than 80% must be repaired or replaced.[14] Although PHMSA did not dispute the validity of the 2009 edition of B31G, it stated that the law requires that PHMSA enforce the regulations as written, which includes enforcing the industry standards that had been properly vetted and incorporated into the regulations through a public notice and comment process.[15] PHMSA continued that the 1991 edition of B31G does not allow for strength calculations or provide

[12] Hearing Transcript, pages 29 and 30; Response, page 2 and 3. RPR is the ratio of the predicted burst pressure to the Maximum Allowable Operating Pressure (MAOP).

[13] Response, at 2 ("PE mitigates the risk associated with leaking anomalies by aerial patrols and surveys and has demonstrated with historical data that external corrosion related leaks are effectively managed and as such do not pose a threat to public safety."); Hearing Transcript, Pages 29- 30, lines 24 – 2 (" . . and mostly the subpart O regulations for natural gas transmission lines are focused on preventing or reducing the likelihood of large releases, or pipeline ruptures."); page 30, lines 21 – 23. ("[T]the short, deep flaws, if they produce a release at all, are almost certainly going to be a leak rather than a rupture."); page 32, lines 10 -14 ("And we are doing that by making our primary determination of immediate response conditions in this kind of case based on the RPR, plus the management of leaks and potential leak conditions.").

[14] ASME B31G-1991, Fig. 1-2.

[15] Hearing Transcript Pages 39 – 40.

alternative options when the wall loss surpasses 80%.[16] In further support of its position, PHMSA cited its Gas IM FAQ 241, which states that operators may not exclude metal loss indications of more than 80% from immediate repair requirements even if B31G or RSTRENG calculations predict a failure pressure greater than 1.1 times MAOP.[17]

PHMSA also differed with Panhandle's assertion that the threat of leaks can be "managed" by aerial patrols and that leaks do not pose a threat to public safety.[18] It pointed out that ASME B31.8S-2004 requires "immediate response" for "immediate or near term *leaks* or ruptures."[19] (emphasis added.) PHMSA also pointed out that the transmission lines at issue transport unodorized gas, and any leak, especially one that could go unnoticed by the public, jeopardizes safety.[20]

I do not agree with Respondent's arguments. First, I agree with PHMSA that § 193.933(d)(1) is a prescriptive, rather than performance based regulation. The last sentence in the provision states, "An operator must treat the following *conditions* as immediate repair conditions:" (emphasis added.) This means that if any of the conditions exist, an immediate repair is required. The presence of a corrosion area with greater than 80% wall loss triggers (i), mandating an immediate repair. Contrary to Panhandle's arguments, the language in (iii) simply means that if neither (i) nor (ii) require an immediate repair, an immediate repair may still be required if, in the judgment of the operator or its contractor, an anomaly "requires immediate action." Most importantly, PHMSA established that Panhandle erroneously relied on the 2009 edition of B31G that has not been incorporated into the Pipeline Safety Regulations.

In its Closing, Panhandle raised arguments not discussed in its Response or during the hearing. First, Respondent stated that PHMSA erroneously focused solely on the 1991 edition of ASME B31G for determining immediate repair conditions. Instead, Panhandle pointed to the language in § 192.933(d)(1) that states that an operator's evaluation and remediation schedule *must* follow ASME/ANSI B31.8S, section 7. Presumably, Respondent raised this argument because section 7, "Response to Integrity Assessments and Mitigation (Repair and Prevention)"of B31.8S mentions the RPR methodology and 1.1 ratio. However, the subject matter of section 7 is not evaluation of anomalies; it is the appropriate *response to* the information obtained through those evaluations, i.e. repair, replacement, pressure reduction, etc. Section 7 reviews which indications require immediate response, and it includes "any corroded areas that have a predicted failure pressure less than 1.1 times the MAOP *as determined by ASME B31G* or equivalent." Therefore, Section 7 is merely referencing the edition of B31G that PHMSA has not incorporated; it does not provide an independent means of determining pipe strength of wall loss areas.

Next, Respondent argues that § 192.933(d)(1)(i) allows for "an alternative equivalent method of remaining strength calculation." It contends that the 2009 version of ASME/ANSI B31G qualifies as an "alternative equivalent." I disagree. Given the substance of this Item, PHMSA

[16] ASME B31G-1991, Fig. 1-2.
[17] Frequently – Asked Question FAQ # 241, available at, http://primis.phmsa.dot.gov/gasimp/faqlist.gim
[18] Response at 2. ("PE mitigates the risk associated with leaking anomalies by aerial patrols and surveys and has demonstrated with historical data that external corrosion related leaks are effectively managed and as such do not pose a threat to public safety.")
[19] ASME B31.8S-2004, Section 7.2.3.
[20] Hearing Transcript Page 51

does not consider the 2009 version of B31G to be "equivalent" because the 2009 edition does not treat areas of greater than 80% wall loss as immediate repair conditions.

Lastly, Respondent argues that PHMSA incorrectly interpreted the 1991 edition of B31G to require "immediate" repair or replacement for corrosion areas of greater than 80% depth because Figure 1-2 does not give a timeframe for the repair or replacement. Respondent argues that, given this fact, it is compliant with the 1991 edition because it "currently schedules 80% anomalies, which meets the guidance to repair or replace."[21] Although this statement is not consistent with the arguments it raised at the hearing and in its Response, I agree that the figure does not give a timeframe for repair or replacement. The 1991 edition of B31G does not discuss timeframes for repair but provides a methodology and calculations for pipeline operators to measure pipe strength and safe operating pressure depending on the size and depth of corroded areas. Figure 1-2 simply states that these calculations do not apply to 80% anomalies because they must be repaired or replaced. On the other hand, ASME B31.8S-2004 does provide for repair timeframes. It states that, "any defect found to require repair or removal shall be promptly remediated by repair or removal unless the operating pressure is lowered to mitigate the need to repair or remove the defect."[22] Given that the relevant edition of B31G requires "repair or removal," of corrosion areas of greater than 80%, ASME B31.8S-2004 requires prompt remediation by repair or removal of those areas.

Accordingly, I find that Respondent's procedures for determining immediate repair conditions are inadequate to ensure safe operation of its pipeline system. Pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237, Respondent is ordered to make the following changes to its IMP. Respondent must—

1. Amend the procedures for evaluating anomalies indicated by the tool but not identified as defects requiring immediate repair. The IMP must provide for additional engineering analysis on anomalies not identified as requiring immediate repair; this process should include data from some combination of the following: previous excavations, confirmation digs, results of concurrent inspections, comparison to prior inspections, and applying the vendor-supplied accuracy specification.

2. Amend SOP J.14, "In-Line Inspection: Data Integration Analysis and Response" and all appropriate procedures to ensure that anomalies exceeding 80% wall loss are identified as immediate repair conditions.

3. Complete the above items and submit documentation of completion within 30 days of receipt of this Order. Submit documentation to the Director, Southern Region, Pipeline and Hazardous Materials Safety Administration, 233 Peachtree Street NE, Suite 600 Atlanta, Georgia 30303.

The Director, Southern Region, OPS may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

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[21] Closing at Item 5.
[22] ASME B31.8S-2004, Section 7.2.1 Metal Loss Tools for Internal and External Corrosion.

Failure to comply with this Order may result in administrative assessment of civil penalties up to $100,000 per day for each violation and in referral to the Attorney General for appropriate relief in a district court of the United States. The terms and conditions of this Order Directing Amendment are effective upon receipt.

__________________________________ ____________________

Jeffrey D. Wiese Date Issued
Associate Administrator
for Pipeline Safety