U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

233 Peachtree Street Ste. 600
Atlanta, GA 30303

WARNING LETTER

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

March 14, 2008

Mr. Jeff Burke
President & General Manager
Kentucky West Virginia Gas Company
748 North Lake Drive
Prestonsburg, KY 41653

CPF No. 2-2008-1006W

Dear Mr. Burke:

On August 27-31, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected your Integrity Management Program at Prestonsburg, Kentucky.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§192.919 What must be in the baseline assessment plan?**
   (e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

   A potential issue was identified that adequate precautions were not specified in the procedures implemented to ensure that baseline assessments are being conducted in a manner that minimizes environmental and safety risks. The concern stems from an employee injury during the August 15, 2007 hydrostatic pressure test for a High Consequence Area (HCA) number 22a. Root cause analysis of the incident by the operator found that qualified personnel made errors in following the company procedures.

2. **§192.917 How does an operator, identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
   (a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must

consider include, but are not limited to, the threats listed in AMSE/ANSI B31.8S (ibr, see §192.7), section 2.

1) The threat identification process, as described in the IMP section 5.6.3, has not adequately considered or evaluated interactive threats as stated in ASME B31.8S, Section 2.2.
2) The data for the threat identification and risk assessment has not been adequately checked for accuracy as stated in ASME B31.8S, Section 4.1. Specific examples include accuracy or completeness of data related to effective one-call system and atmospheric corrosion.
3) The IMP does not adequately address integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to identify locations of potential third party damage as stated in ASME B31.8S, Section 4.5.

3. **§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**
   (b)(3)(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examinations of indications.

    1) The ECDA Plan does not have adequate criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examinations of indications.
    2) The ECDA Plan in 6.1 specifics that the remaining half life to be used for calculating the reassessment interval is based on the "scheduled" indication and not the largest unique indication found per NACE 0502-2002 and the interpretation of this requirement from the NACE Technical Committee. *The reassessment intervals are based on "scheduled" indications since all "immediate" indications will have been assessed during the direct examination step and "monitored" indications are expected to experience insignificant growth.*
    3) The ECDA Plan in 6.5.2 does not have a provision to reduce the re-assessment interval based on conditions found other than stating what appropriate federal regulations must be evaluated. *When defects are found (i.e. there are scheduled defects left unexcavated) the reassessment interval for each ECDA region is one-half of the remaining life calculated in 6.5.1. However, the maximum reassessment interval for the region may be further limited by the most restrictive criteria from one or more of the following regulations, codes, and standards: 49CFR192, 49CFR194, ASME B31.8, ASME B31.8S, or NACE RP0502.*

4. **§192.939 What are the required reassessment intervals? An operator must comply with the requirements in establishing the reassessment interval for the operator's covered pipeline segments.**

1) The IMP Section 13, dated June 5, 2007 does not accurately and clearly describe the process for reassessment of covered segments on which a baseline assessment was conducted. This program element remains in a "framework" status with significant additional effort needed to meet the regulation requirements.
2) The process to assure reassessment intervals are appropriate is not accurately presented, including several technical issues in Section 13 and Figures 13-2, 13-2A, 13-3, 13-4 and 13-5, for example:

   - Flow chart logic for some yes/no decisions are incorrect
   - Decision block C2 on Figure 13-2 appears to be incorrect
   - Several blocks on Figures 13-2 & 13-5 need further basis for decision criteria
   - No safety margin related to Tmin
   - No technical basis for corrosion rate formula in Figure 13-5
   - C25 yes option on Figure 13-4 is missing
   - LSR is incorrectly shown as an option on Figure 13-3

   These examples exhibit the need for a thorough review and revision of Section 13 to assure the process by which integrity intervals are determined provide a sound basis upon which to establish reassessment intervals.

5. **§192.935 What additional preventive and mitigative measures must an operator take?**
   (b)(1)(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

   The IMP does not adequately address collecting, in a central database, location-specific information on excavation damage. The process for using the Central Incident Database and the associated Audit Action Register to review and analyze incidents, including root cause analysis, should be in the IMP Plan.

6. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
   (e)(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

   The IMP does not address the requirement to remediate corrosion in similar non-covered segments when serious corrosion is discovered in a covered segment.

7. **§192.947 What records must an operator keep?**
   (d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

   Sufficient documentation was not available to support the basis for many decisions, analysis, and process developed and used to implement and evaluate the IMP. Examples include bases for: Threat of Concern (TOC) methodology, historical non-corrosivity of gas, not adding automatic shut-off valves or remote control valves; corrosion growth equation in Figure 13-5; and disposition of discrepancy between test acceptance pressure and test plan pressure. A process should be developed to require documentation of the basis for decisions.

Under 49 United States Code § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violations persist up to a maximum of $1,000,000 for any related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceeding at this time. We advise you to correct the item(s) identified in this letter. Failure to do so will result in Kentucky West Virginia Gas Company being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF No. 2-2008-1006W.** 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).

Sincerely,

M. Shoaib

Mohammed Shoaib
Director, Southern Region
Pipeline and Hazardous Materials Safety Administration