NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

October 20, 2011

Mr. William Cope
Vice President, Eastern Operations
Southern Natural Gas
569 Brookwood Village, Suite 501
Birmingham, Alabama 35209

CPF 4-2011-1011M

Dear Mr. Cope:

In 2010, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Southern Natural Gas (SNG) procedures, and records in the states of Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina, and the Gulf of Mexico.

As a result of the inspection, PHMSA has identified the apparent inadequacies found within plans or procedures, as described below:

1. **§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.)

§192.915 What knowledge and training must personnel have to carry out an Integrity management program

(b) Persons who carry out assessments and evaluate assessments results. The integrity management program must provide criteria for the qualification of any person – (1) who conducts an integrity assessment allowed under this subpart; or (20 who reviews and analyzes the results from an integrity assessment and evaluation; or (3) who makes decisions on actions to be taken based on these assessments.

SNG's procedures for personnel who review and evaluate External Corrosion Direct Assessment (ECDA), pressure testing and Stress Corrosion Cracking Direct Assessment (SCCDA) results are inadequate. SNG utilizes El Paso Pipeline Group's (EPPG) procedures. These procedures do not specifically require personnel who review and evaluate ECDA, pressures testing and SCCDA results to meet acceptable qualification standards.

2. §192.911 What are the elements of an integrity management program?

See Above.

§192.915 What knowledge and training must personnel have to carry out an integrity management program?

(b) See Above

EPPG has not specified the qualification requirements for vendor personnel who perform ECDA and SCCDA; and approve the test results of their procedures. EPPG uses contract personnel to perform the field work, and to review and analyze the data. EPPG reviews qualifications by resumes, experience, etc of the contractor personnel for the results, but the written procedures do not specify what is actually being performed.

3. §192.911 What are the elements of an integrity management program?

See Above.

§192.915 What knowledge and training must personnel have to carry out an integrity management program?

(b) See Above.

EPPG has not specified the qualification requirements for vendor personnel who review the results of ECDA methods and perform information analysis. EPPG uses contract personnel to perform the field work, and to review and analyze the data. EPPG reviews qualifications by resumes, experience, etc of the contractor personnel for the results, but the written procedures do not specify what is actually being performed.

4. §192.911 What are the elements of an integrity management program?

See Above.

(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

§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 B31.8 (incorporated by reference, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

EPPG's written procedure for vendor In Line Inspection (ILI) specifications is inadequate. The team reviewed EPPG's procedures for complete and adequate vendor ILI specifications. The procedures are not adequate as that they do not define actions/processes to be taken if the review cannot be completed within 180 days of assessment completion.

5. §192.911 What are the elements of an integrity management program?

(b) See Above.

§192.921 How is the baseline assessment to be conducted?

(a)(1) See Above.

EPPG's written process for validating ILI results to ensure that accurate integrity assessment results are obtained is inadequate. As anomaly evaluations are taking place, it is the responsibility of the evaluator to note the amount of correlations between ILI reported data and actual in field measurements. Any significant discrepancies or problems with anomaly location, characterization, or sizing should be communicated to the ILI vendor and Pipeline Service's support personnel to determine if any further data analysis or other actions are warranted.

6. §192.911 What are the elements of an integrity management program?

See Above.

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(b) ***Data gathering and integration.*** **To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.**

SNG's procedures are inadequate as they do not provide details on the integration and evaluation of corrosion control program information with the ILI assessment results. SNG's POP 306, *Section 6 - Future Mitigation* does not identify details of how this is to be accomplished.

7. §192.911 What are the elements of an integrity management program?

See Above.

(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?

(a) ***General requirements*****. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. 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 condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.**

(1) ***Temporary pressure reduction.*** **If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG," incorporated by reference, *see* §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See appendix A to this part for information on availability of incorporation by reference information.) An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.**

(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:

EPPG's procedures for Repair and Pressure Reduction for Immediate Repair Conditions is inadequate. EPPG's written procedures, state that "*Repair and Pressure Reduction for Immediate Repair Conditions: Immediate repair conditions will be examined within 5 days of "Discovery of Condition" except where this is not practicable. When EPPG cannot excavate and examine the anomaly within 5 days of discovery, EPPG will do so as soon as it is practicable and will maintain a temporary pressure restriction until the anomaly is examined and remediated as required. A pressure restriction will be implemented based on the procedures outlined in POP 306, Section 4.1 (per ASME/ANSI B31G or AGA Pipeline Research Committee Project PR-3-805) or the pipeline removed from service until repaired*."

PHMSA's Gas Integrity Management *FAQ-134. Timing of Pressure Reduction in Immediate Repair Conditions* states "Pressure should be reduced, or the line should be shut down, as soon as practicable once an immediate repair condition is identified." and FAQ-*215. 5-day B31.8S requirement for immediate conditions* states "...Pressure reductions should be taken promptly."

8. §192.605 Procedural manual for operations, maintenance, and emergencies.

(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part.

§192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971 must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of §192.461.

.

EPPG's procedures for external corrosion control are inadequate. EPPG's procedures (Section 700) covers that pipe will be inspected when exposed and the inspection will be documented on the Pipeline Inspection Report (PIR). The PIR covers coating condition in various categories: Good, Fair, Excellent, etc. When queried on standards for the coating evaluation, or instructions on filling out the PIR, these standards are subjective and are covered in training with corrosion control technicians. EPPG needs written criteria describing

the coating assessment ratings on the PIR, so the coating assessment by the tech in the field is not subjective.

9. §192.605 Procedural manual for operations, maintenance, and emergencies.

(b)(2) See Above.

§192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7½ months.

EPPG's procedures for internal corrosion control are inadequate. The procedures do not define evaluation criteria for the monitoring program. Specifically, the procedure does not identify the criteria SNG uses to determine if the mitigative measures are adequate or if additional mitigative measures are required.

10. §192.605 Procedural manual for operations, maintenance, and emergencies.

(b)(2) See Above.

§192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7½ months.

EPPG's procedures for internal corrosion control monitoring are inadequate. EPPG has a corrosion control database (TSIMS), with information about pigging, coupons, etc. EPPG does not have a written procedure/process that addresses TSIMS.

During the inspection, the team reviewed EPPG's Manual of Engineering Standards, Corrosion Control that is used for determining when supplemental action is needed. EPPG does not have a specific corrosion rate defined in their procedures and what would be the trigger rate when treatment is to be taken.

11. §192.605 Procedural manual for operations, maintenance, and emergencies.

(b) (2) See Above.

§192.485 Remedial measures: Transmission lines.

(a) General corrosion. Each segment of transmission line with general corrosion with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so

closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B 31G or the procedure in AGA Pipeline research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pie wall, subject to the limitations prescribed in the procedures.

EPPG states in their procedures that "*For anomalies located outside an HCA the following will be treated as immediate repair condition:*

*i. Any metal loss anomaly that has a predicted failure pressure (Pfail) less than or equal to 1.10 * MAOP (maximum allowable operating pressure.*

ii. Any metal loss anomaly with a depth that is equal to or greater than 80% of the nominal pipe wall thickness AND that Pipeline Services feels is an immediate threat to the integrity of the pipeline;

iii. *Any other anomaly that Pipeline Services feels warrants immediate action*."

According to §192.485 general corrosion must be repaired when there is a remaining wall thickness less than that required for the MAOP, which is established within §192.485(c) and which is equivalent to a (Pfail) less than or equal to 1.39 * MAOP. The 1.39 value is equivalent to 72% of SMYS while 1.1 (referenced by the operator) is equivalent to 91% SMYS. Operators are not allowed to operate at a 1.1, except in HCAs. The procedures allow the EPPG to not repair for the required MAOP, outside of HCAs.

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 (not mandated) that SNG maintain documentation of the safety improvement costs associated with fulfilling this Notice of Amendment (preparation/revision of plans, procedures) and submit the total to R.M. Seeley, Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration. In correspondence concerning this matter, please refer to **CPF 4-2011-1011M** 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

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

The team reviewed EPPG's procedures for complete and adequate vendor ILI specifications. The procedures do not define actions/processes to be taken if the review cannot be completed within 180 days of assessment completion.