NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY

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 4-2011-1012

Dear Mr. Cope:

From January 1 to December 31, 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, records and pipeline facilities in the states of Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina, and the Gulf of Mexico.

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. §192.911 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.

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.

(j) Record keeping provisions meeting the requirements of §192.947.

§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE RP 0502–2002 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502–2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

§192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(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;

SNG did not maintain proper or complete documentation supporting the decisions made in performing the Pre-Assessment step for the ECDA of the Graniteville Mills Expansion Line. During the review of the Pre-Assessment step for ECDA of the Graniteville Mills Expansion line shows two casings in the report pre-assessment data. The HCA was treated as one region, rather than two ECDA Regions which would have been required if there were cased crossings identified in the HCA segment per table 6.1 of El Paso's IM program.

In 2007, SNG performed an ECDA of the 8" Graniteville Mills Expansion Line. The Executive Summary of SNG's ECDA report *External Corrosion Direct Assessment; 8" Graniteville Mills Expansion Line - HCA No. 1126; Valve Section MP 3+1355.87 – Sta. 13+56 to Sta. 30+32; El Paso Work Request No. PS07-107* states:

> "The Pre-Assessment step of the ECDA process was performed in July 2007. During Pre-Assessment it was determined that ECDA was feasible and practicable for this HCA segment, and that the entire HCA segment could be defined as one ECDA region."

Section 1.2 Assessment of ECDA Feasibility of SNG's ECDA report states:

> "Certain ground surface conditions such as paved and frozen: Only one short length of the pipeline segment lies below pavement, approximately 4-1/2 feet below a blacktop road. The pipeline is not cased under the road. This situation does not preclude the use of Indirect Inspection tools."

The *Pre-Assessment Data Sheet* in *Appendix 3 - Pre-Assessment Data Sheet* of SNG's ECDA report identifies two (2) casings in the *Casing Length(s)* line: "130 feet (from 19+82 to 21+12) and 110 feet (from 22+88 to 23+98)". During the inspection SNG personnel stated that the two (2) casings identified in the *Pre-Assessment Data Sheet* were horizontal directional drills rather than casings, but this information was not documented in SNG's ECDA report.

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

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SNG did not implement their ECDA plan for conducting indirect examinations. SNG did not complete indirect examinations over the entire High Consequence Area (HCA) segment of the 8" Graniteville Mills Expansion Line with the tools selected during the External Corrosion Direct Assessment (ECDA) performed in 2007.

In 2007, SNG performed an ECDA of the 8" Graniteville Mills Expansion Line. SNG selected three (3) indirect assessment tools to perform the indirect examination of the HCA segment. *Appendix 5 - Indirect Inspection Tool Selection and Specifications* of SNG's ECDA report *External Corrosion Direct Assessment; 8" Graniteville Mills Expansion Line - HCA No. 1126; Valve Section MP 3+1355.87 – Sta. 13+56 to Sta. 30+32; El Paso Work Request No. PS07-107* identifies that an interrupted Close Interval Survey (ICIS) was selected as an indirect assessment tool. In performing the ICIS of the HCA segment a portion of the pipeline from Station 20 + 27.9 to Station 21 + 06 was not inspected by the CIS as identified in the chart and spreadsheet in *Appendix 7 - Indirect Inspection Data and CorrVision Data Plot.*

During the pre-assessment SNG identified the High Consequence Area (HCA) as one region for purposes of the ECDA even though the HCA contained a paved road crossing. SNG based their decision assuming that the paved road crossing would have holes drilled in the surface to allow the indirect assessment tools to be used across the road crossing. SNG's records for the indirect assessment of the pipeline show that the ICIS was not conducted across the road.

During a follow-up onsite inspection, SNG informed PHMSA that the ICIS was completed over the paved crossing.

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

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(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:**

SNG did not take prompt action following the discovery of an Immediate Condition nor did they take the required pressure reduction within the timeframe specified in the regulations. On Friday September 21, 2007, SNG published an Initial Response Memo for the integrity assessment of the SNG 24" North Main Loop & 2nd Loop pipelines between DeArmanville Compressor Station and Winston Gate. The Initial Response Memo identified twelve (12) Immediate Conditions and identified a pressure reduction to be taken. From the internal memo:

> "*A pressure restriction must be put in effect limiting the MOP to 80% of the maximum pressure within the past 120 days between the Heflin Gate (MP 391.970) and the Rome-Calhoun Gate (MP 400.244) and the Mt. Zion Gate (MP 413.852). This restriction must be put in place as soon as possible and not to exceed 5 days of the Discovery Date (9/21/2007)."*

On Monday September 24, 2007, SNG reduced the pressure in the pipelines. Though SNG followed its' procedures (*Pipeline Operating Procedures Manual, Operating and Maintenance, Section 306, In-Line Inspection and Data Analysis*, Effective Date: 08/24/2009 [POP 306]) it did not comply with the IM regulatory requirement to take the pressure reduction as soon as practicable, promptly.

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."

SNG did not take the pressure reduction either promptly or as soon as practicable, nor document the reasons for the three (3) day delay in taking the pressure reduction.

4. §192.605 Procedural manual for operations, maintenance, and emergencies.

(a) *General*. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

SNG did not follow their Site Specific Internal Corrosion Action Plan (ICP) for the North Main Loop Line. SNG did not run a cleaning pig in their North Main Loop Line, from Tarrant Compressor station to Moody Gate in 2007 per their Site Specific Internal Corrosion Action Plan (ICP). The ICP is developed and maintained by SNG personnel. The documentation provided by SNG demonstrated that the cleaning pig has not been run since 2004.

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§192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

SNG did not follow their procedures for monitoring gas quality or taking appropriate actions for the Olga station. During the inspection, the team was informed that SNG utilizes the El Paso Pipeline Group, Gas Quality Guidelines, seventh edition. These procedures state company personnel must arrive at a determination as to whether the gas flow is conforming or non-conforming in relation to the particular company tariff. One particular standard in the tariff for SNG is to not transport gas with a water vapor of 7 lbs/MMscf or more. While the particular circumstances of each case will determine the duration of the Evaluation and Decision-Making Period, the guidelines state that this review shall not exceed 72 hours by company personnel.

During the field evaluation, on September 15, 2010, the inspector and field personnel noted that the moisture analyzer at Olga was indicating that the water vapor was registering 7.5lbs/MMscf. It was identified during the inspection, that SNG had noted a “High” alarm from an on-line moisture analyzer on September 9, 2010. Additional documentation indicated that SNG was aware of the “high” alarm from the moisture analyzer on September 6, 2010; SNG was reading 9.5 lbs/MMscf for water vapor at Olga. Documentation was received from SNG, stating that multiple trips to producer locations were made to verify location conditions, but no dates were documented. On September 23, 2010, a technician was sent out to troubleshoot the analyzer. The inspection team requested the operator’s “Cooperative Short Term Plan” but none was completed. SNG had information that indicated they transported gas for 14 days when the on-line moisture analyzer register over 7.0 lbs/MMscf. Correction action was not completed for approximately 14 days. This exceeded the time allowed in their procedure.

6. §192.465 External corrosion control: Monitoring.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

SNG did not take prompt remedial action to repair a damaged test station on the Gadsden Branch Loop Line at Steele Raceway, Mile Post 22.204. SNG deactivated the test point on April 16, 2009 when the SNG technician found the test point was destroyed. SNG did not take other actions to discount the necessity of test point to determine if the CP was effective. SNG initiated a Maximo Work Order to repair the test station on August 26, 2010, after the issue was identified during the inspection.

7. §192.475 Internal corrosion control: General.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence for corrosion. If internal corrosion is found –

(1)The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2)Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and;

(3)Steps must be taken to minimize the internal corrosion.

SNG did not inspect the internal surface for evidence of corrosion, when pipe was removed. In the first instance, SNG performed a hot tap on the 24" pipe to install a stopple for the Mississippi hub tie-in. On June 14, 2010, when the pipe was exposed, the operator observed crack like indications on the pipe. The paperwork indicates that the external examination was performed. SNG personnel contacted Houston and informed them of the crack like indications. They were instructed to expose the pipe until there was no more crack like indications. At MP 8+2965.6 from station #451+28 to 452+75.1 the pipe was excavated and removed from the system and sent the El Paso Laboratory, in El Paso, Texas.

In the second instance, SNG removed a segment of the North Main 2nd Loop Line at MP 433 (Project 143225) on November 24, 2009. An anomaly dig was conducted on November 16,

2009. The coating condition and the external pipe condition were noted and documented on an El Paso Inspection Form Report on November 16, 2009. The excavation and documentation of the coating and external pipe condition was conducted by the area employees in the Fayetteville office. SNG later decided to cut out the segment of pipe. The cut out portion of the project was turned over to the Pipeline Services team from the Birmingham, AL (HQ.) office. The segment was cut out on November 24, 2009. Pipeline Services did not update the internal pipe condition on the existing (online) Inspection Form Report. Pipeline Services also did not create a new Inspection report to document the internal pipe wall condition inspection. Records indicate that there was no internal inspection performed.

The evidence demonstrates that the operator violated § 192.475 by failing to inspect the internal surface for internal corrosion. In the event that such inspections were, in fact, performed, the evidence demonstrates the operator violated §192.491 by failing to maintain a record of each inspection required by this subpart.

8. §192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

During the field evaluation on September 15, 2010, SNG provided helicopter over flight over the entire SNG right-of-way (ROW) in the state of Louisiana from offshore Main Pass 289 to Toca and from Toca to the Louisiana/Mississippi state line. During the flight, it was noted that a mobile home was over the SNG pipeline ROW. SNG employees informed the inspector that the mobile home has been on their line since 2009. The mobile home was being towed and broke down and was then left over the pipeline ROW. On December 10, 2010, the mobile home was removed at Adolphus Road and is no longer on the SNG ROW.

9. §192.199 Requirements for design of pressure relief and limiting devices. Except for rupture discs, each pressure relief or pressure limiting device must:

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard.

At SNG's Dublin #1 Regulator station the discharge stack for the relief valve was not positioned to vent to a safe area, the vent was directed to vent gas into the roof of the shed covering the station. This office understands that SNG has corrected this issue, by cutting the roof so that the vent is now to discharge to the atmosphere without any obstruction.

10. §192.163 Compressor stations: Design and construction.

(d) Fenced areas. Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building

must open outward and, when occupied, must be openable from the inside without a key.

At the Pell City Compressor Station, there is a gate on the south side of the fence next to the station Control Building that was locked and not equipped with a “bump bar,” the gate was within 200-ft of the compressor building. This office understands that SNG has equipped Pell City Compressor Station gate with a “bump bar.”

Proposed Civil Penalty

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 violation persists up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $72,900.00 as follows:

Item number	PENALTY
1	$29,100.00
5	$21,600.00
7	$22,200.00

Warning Items

With respect to items 2, 3, 4, 6, 8, 9, and 10, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these items. Be advised that failure to do so may result in SNG being subject to additional enforcement action.

Response to this Notice

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.

In your correspondence on this matter, please refer to **CPF 4-2011-1012** 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

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