



U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

August 20, 2007

Robert S. Bahnick
Senior VP of Operations and Technical Services
Southern Star Central Gas Pipeline
4700 Highway 56
Owensboro, KY 42301

CPF 4-2007-1012M

Dear Mr. Bahnick:

During the weeks of September 11-14 and 25-28, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Southern Star Central Gas Pipeline (SSCGP) your integrity management procedures in Owensboro, Kentucky.

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

1. **§192.905 How does an operator identify a high consequence area?**
 - (b)(1) **Identified sites. An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.**

SSCGP must revise its IM plan and procedures to:

- A. Ensure the integration of information from routine operations and maintenance activities (e.g., identification of new structures/change in facility use along the right of way) into the HCA identification process.
- B. Detail its process by which local public officials are contacted for information regarding identified sites and specify the periodicity with which officials should be contacted.

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 ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 2, which are grouped under the following four categories:

- (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;**
- (2) Static or resident threats, such as fabrication or construction defects;**
- (3) Time independent threats such as third party damage and outside force damage; and**
- (4) Human error.**

SSCGP must revise its procedures to include guidance on how subject matter experts (SMEs) identify and address potential interacting threats.

3. §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.

SSCGP must revise its procedures to:

- A. Ensure the verification that individual data elements are brought together and analyzed in their context. Integrated data should provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk (e.g., depth of cover, land use).
- B. Ensure provisions exist to collect data identifying if a pipeline line segment includes flash-welded pipe.
- C. Ensure procedures adequately address how data for conditions unique to each pipeline is gathered and evaluated for both covered and similar non-covered segments.
- D. Ensure procedures address how suspect, missing, or unknown information will be addressed in the risk analysis process and include requirements for how and when suspect, missing, or unknown data elements will be collected and managed.
- E. Ensure procedures address the timing for incorporation of new data and requirements to ensure the most current information is available prior to running the risk analysis program.

4. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§192.919, §192.921, §192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

SSCGP must revise its procedures to ensure there is a documented basis for the 1000 foot segmentation used for risk analysis.

5. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(3) Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) ERW pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

SSCGP must revise its IM plan to specify that segments with low-frequency ERW or lap welded pipe or that have manufacturing defects where operational changes could have made them unstable be treated as high-risk segments.

6. §192.921 How is the baseline assessment to be conducted?

(b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(d) Time period. An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

SSCGP's must modify the process to require the development of its baseline assessment plan prior to December 17, 2007 in order to ensure that the 50% completion deadline will be met.

7. 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).

SSCGP must revise its procedures to ensure references to O & M procedures are provided at the appropriate locations in the ECDA process in order to provide the appropriate guidance for consistent application of the process.

8. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) see above

(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.

SSCGP must revise its procedures to:

- A. Provide additional guidance and documentation in order to assure consistent results of the feasibility assessment in the pre-assessment step of the ECDA process.

- B. Provide justification for the spacing of some indirect inspection tool readings that do not meet industry standards or NACE requirements (e.g., acceptability of 30 ft. spacing in paved locations).
 - C. Provide better documentation of the more restrictive criteria required on initial ECDA assessments in the pre-assessment, indirect inspections, and direct examination steps.
9. **§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**
- (b) *see above*
 - (3) **Direct examination.** In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—
 - (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 examination of indications; and**

SSCGP must revise its procedure to ensure adequate internal communications exist on changes in the ECDA plan are documented in the SSCGP ECDA process.

10. **§192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?**
- (c) **The ICDA plan.** An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.
 - (5) **Other requirements.** The ICDA plan must also include--
 - (i) **Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;**

SSCGP must revise its procedures to ensure requirements defining the criteria for making decisions regarding the selection of ICDA regions and determining the feasibility of the ICDA assessment provide sufficient guidance for consistent application of the process.

11. **§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 that 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 that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. 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. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (incorporated by reference, see §192.7) or AGA Pipeline Research Committee Project PR-3-805 ("RSTRENG"; ibid, see §192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in

operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

SSCGP must revise its procedures to ensure that upon discovery of an immediate repair condition, that pressure is reduced as required and remediation is accomplished in a prompt manner.

12. §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.

SSCGP must revise its procedures to ensure IMP procedures require that the date of discovery for an anomaly be documented.

13. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

SSCGP needs to revise its procedures to ensure:

- A. P & M measures reference all of the requirements in ASME B31.8S, evaluate all threats, and evaluate the adequacy of measures already being implemented along with applying the procedures to all relevant threats in each covered segment
- B. An adequate documented decision-making process exists to decide which P&M measures are to be implemented that involves input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control.
- C. The evaluation of both the likelihood and the consequences of a pipeline failure with regard to additional P & M measures. Based on the information reviewed during the inspection, it appears that this concern will be addressed through implementing the new risk model.
- D. The ongoing implementation of P&M measures for all HCAs.

14. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors--swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

SSCGP must revise its procedures to ensure decisions and technical justification for not installing additional automatic or remote acting valves are documented.

15. §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

SSCGP must revise its procedures to ensure the following:

- A. Continual evaluation and assessments in the SSCGP process must specify all of the required elements and sufficient guidance must be provided for consistent application of the process.
- B. The periodic evaluations per the SSCGP procedure (i.e., 2 years) must be revised to reflect the need to update important information on a continual basis.

In regard to Items 1.B, 4, 8, 9, 10, 11, and 12 listed above, SSCGP provided finalized documentation via email to PHMSA on July 5, 2007 of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on these items in response to this Notice.

Response to this Notice

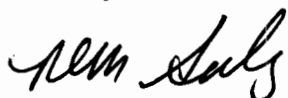
This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit 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 [number of days] 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 4-2007-1012M** 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*